Jennifer Brooks Hutchinson
Senior Counsel
PPL Services Corporation
JHutchinson@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7288

Rhode Island Energy™
a PPL company

March 13, 2023

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-54-NG – The Narragansett Electric Company
Proposed Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan
<u>Responses to PUC Data Requests – PUC Set 4 (Full Set)</u>

Dear Ms. Massaro:

I have enclosed an electronic version of Rhode Island Energy's[1] complete set of responses to the Public Utilities Commission's Fourth Set of Data Requests (Full Set) in the above-referenced matter.[2]

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 22-54-NG Service List
Leo Wold, Esq.
John Bell, Division
Al Mancini, Division

[1] The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company").

[2] Per communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Heidi J. Seddon — March 13, 2023
Date

No. 22-54-NG- RI Energy's Gas Infrastructure, Safety and Reliability (ISR) Plan 2024 - Service List 2/6/2023

Name/Address	E-mail Distribution	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Jennifer Hutchinson, Esq. 280 Melrose Street Providence, RI 02907	JHutchinson@pplweb.com; COBrien@pplweb.com; JScanlon@pplweb.com; JMOBrien@rienergy.com; PLaFond@rienergy.com; NKocon@rienergy.com;	401-784-7288
Steve Boyajian, Esq. **Robinson & Cole LLP** One Financial Plaza, 14th Floor Providence, RI 02903	SBriggs@pplweb.com; JOliveira@pplweb.com; SBoyajian@rc.com; HSeddon@rc.com;	401-709-3359
Division of Public Utilities & Carriers Leo Wold, Esq.	Leo.Wold@dpuc.ri.gov; Margaret.l.hogan@dpuc.ri.gov; Al.mancini@dpuc.ri.gov; John.bell@dpuc.ri.gov; Robert.Bailey@dpuc.ri.gov; Paul.roberti@dpuc.ri.gov; ellen.golde@dpuc.ri.gov;	401-780-2130
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Rod Walter, CEO/President Rod Walker & Associates	Rwalker@RWalkerConsultancy.com; jwalker@rwalkerconsultancy.com;	706-244-0894
Office of Energy Resources Al Vitali, Esq.	Albert.vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Christopher.Kearns@energy.ri.gov;	

	Shauna.Beland@energy.ri.gov; William.Owen@energy.ri.gov; Anika.Kreckel@energy.ri.gov;	
Office of Attorney General Nick Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov;	401-274-4400 x 2297
File an original and five copies Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02888	Luly.massaro@puc.ri.gov; Patricia.lucarelli@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; Christopher.Caramello@puc.ri.gov;	401-780-2107

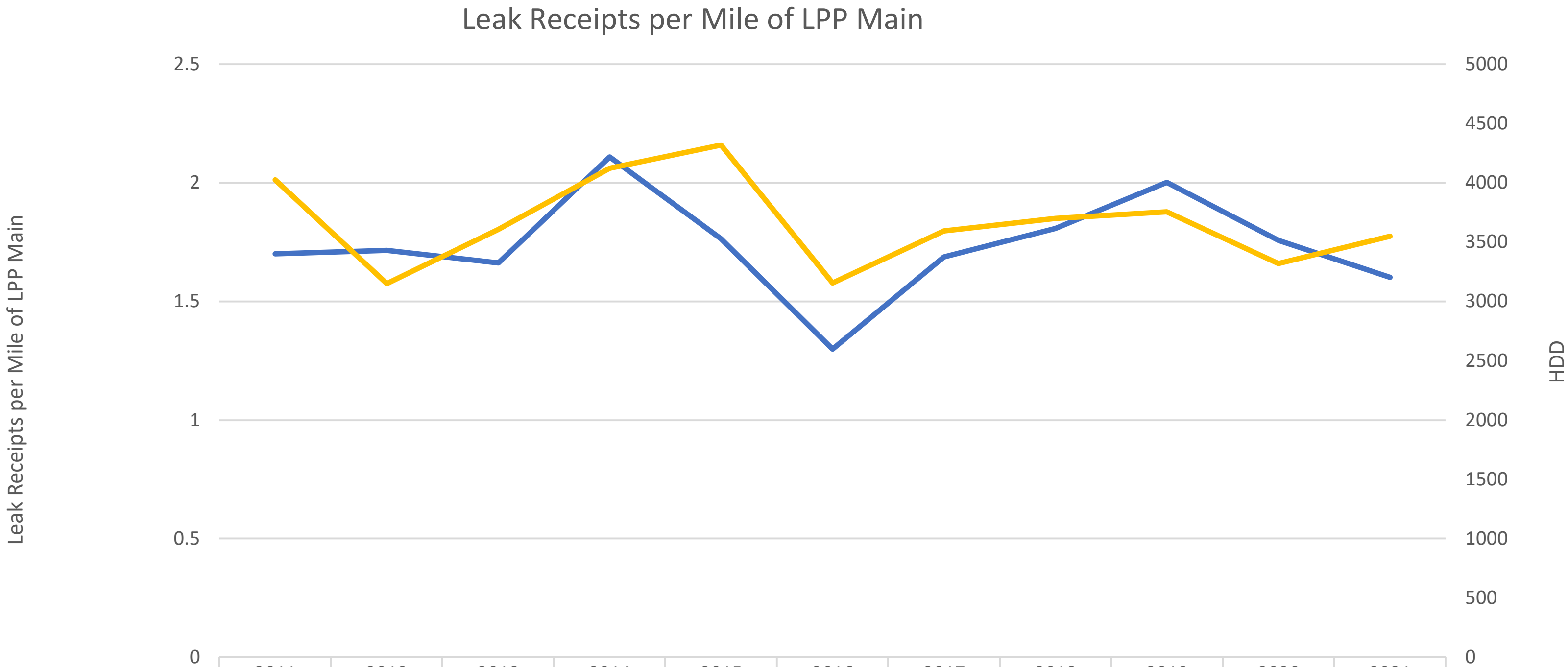
PUC 4-1
Leak Prone Pipes (LPP)

Request:

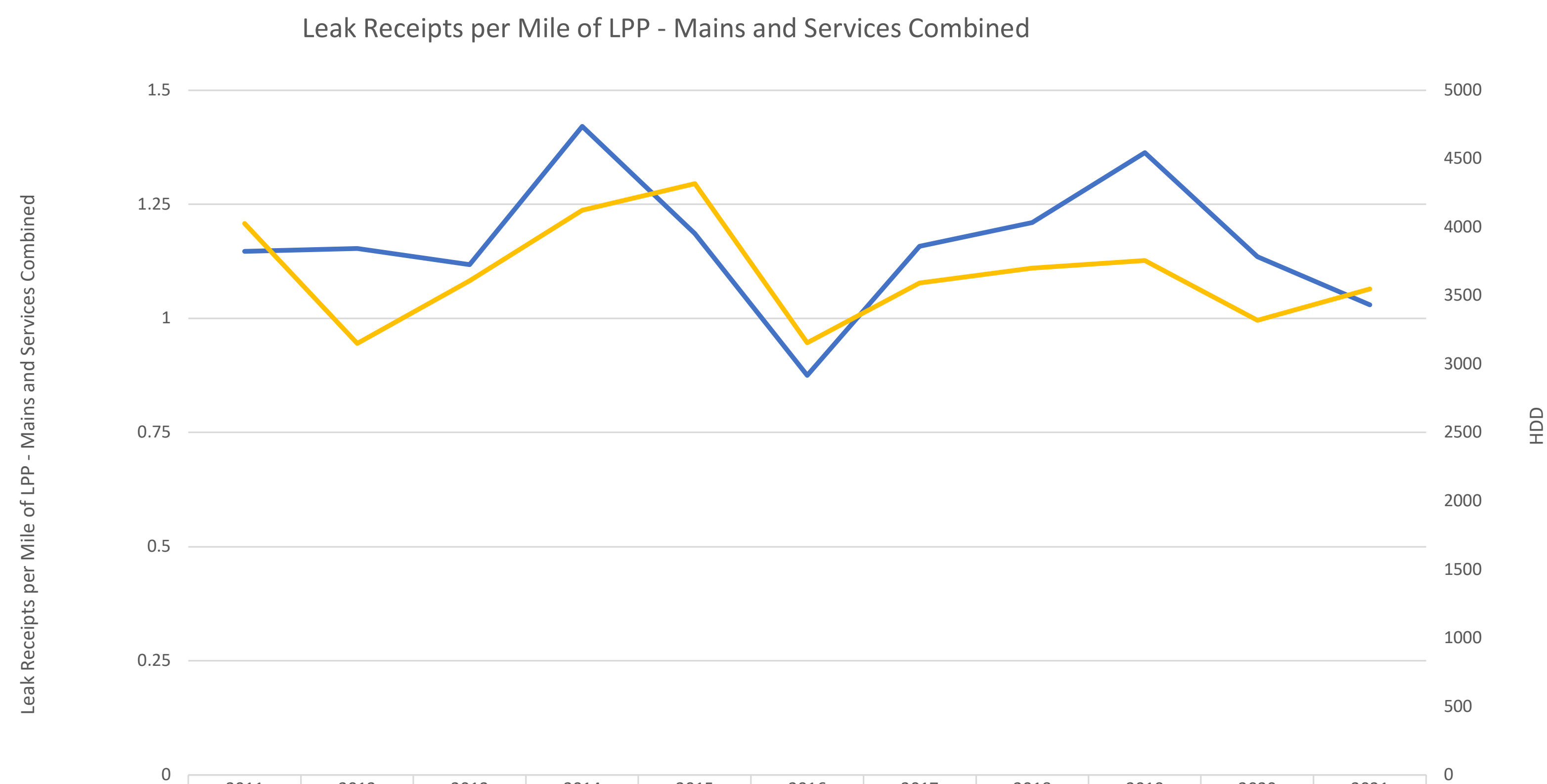
Please update Record Request 14 in Docket 5210 that requested various leak and leak prone pipe data, including the additional year of data. Please note that in this request, the word "per" means "divided by." This means, for example, that a request for a graph of main leak receipts per miles of LPP main inventory means is a request for a single data of (main leak receipts)$_x$/(miles of LLP main)$_x$, where "x" is a given year in the series and the horizontal axis of the plot. Please also replot the HDD data as originally shown but updated for to include the additional year of data.

Response:

Please refer to Attachment PUC 4-1.

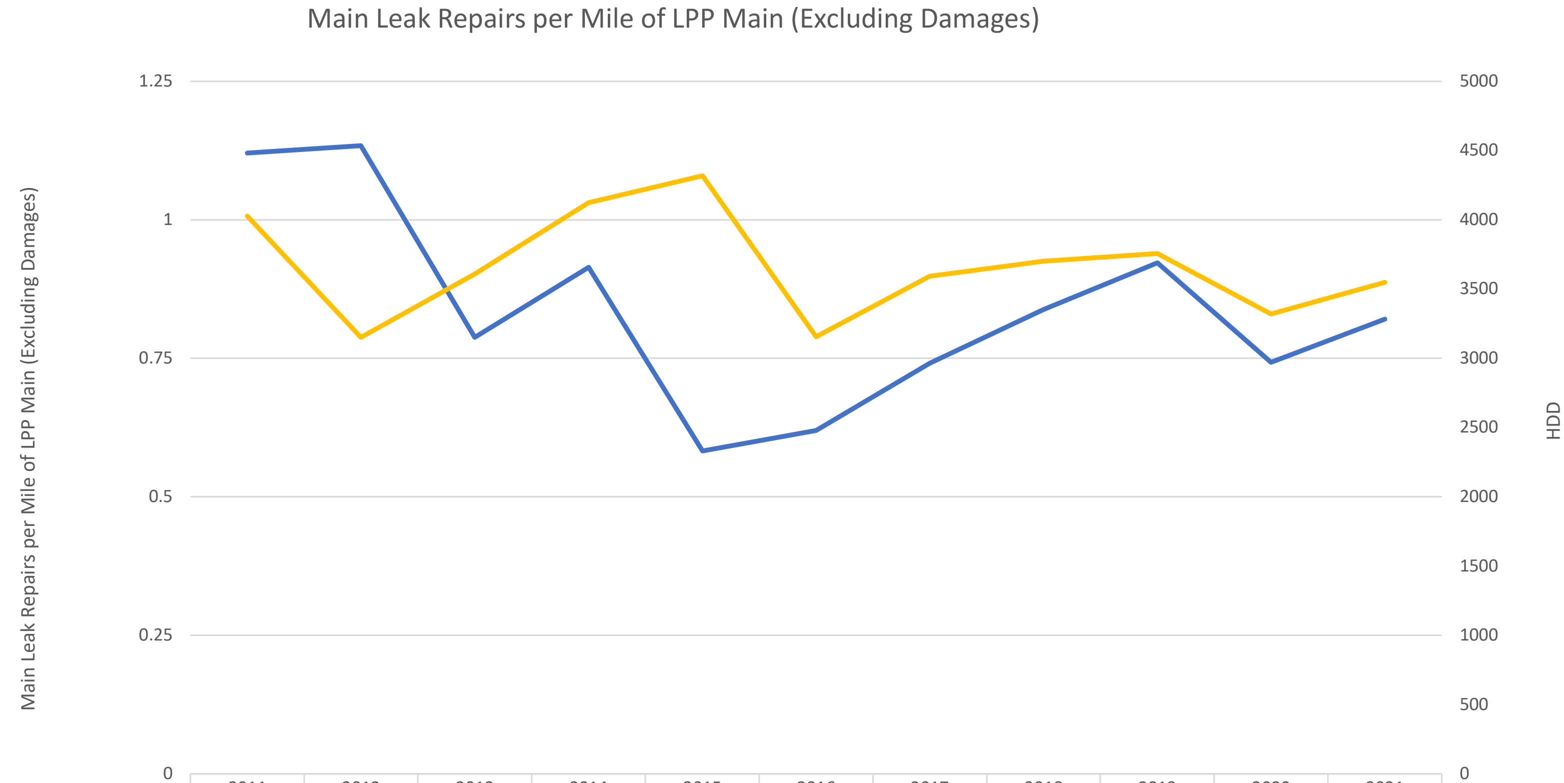


	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
LPP Main (Miles)	1471	1409	1355	1305	1237	1186	1140	1100	1052	989	942
Leak Receipts per Mile of LPP Main	1.70	1.72	1.66	2.11	1.76	1.30	1.69	1.81	2.00	1.76	1.60
HDD	4026	3151	3608	4123	4318	3156	3593	3699	3757	3319	3549



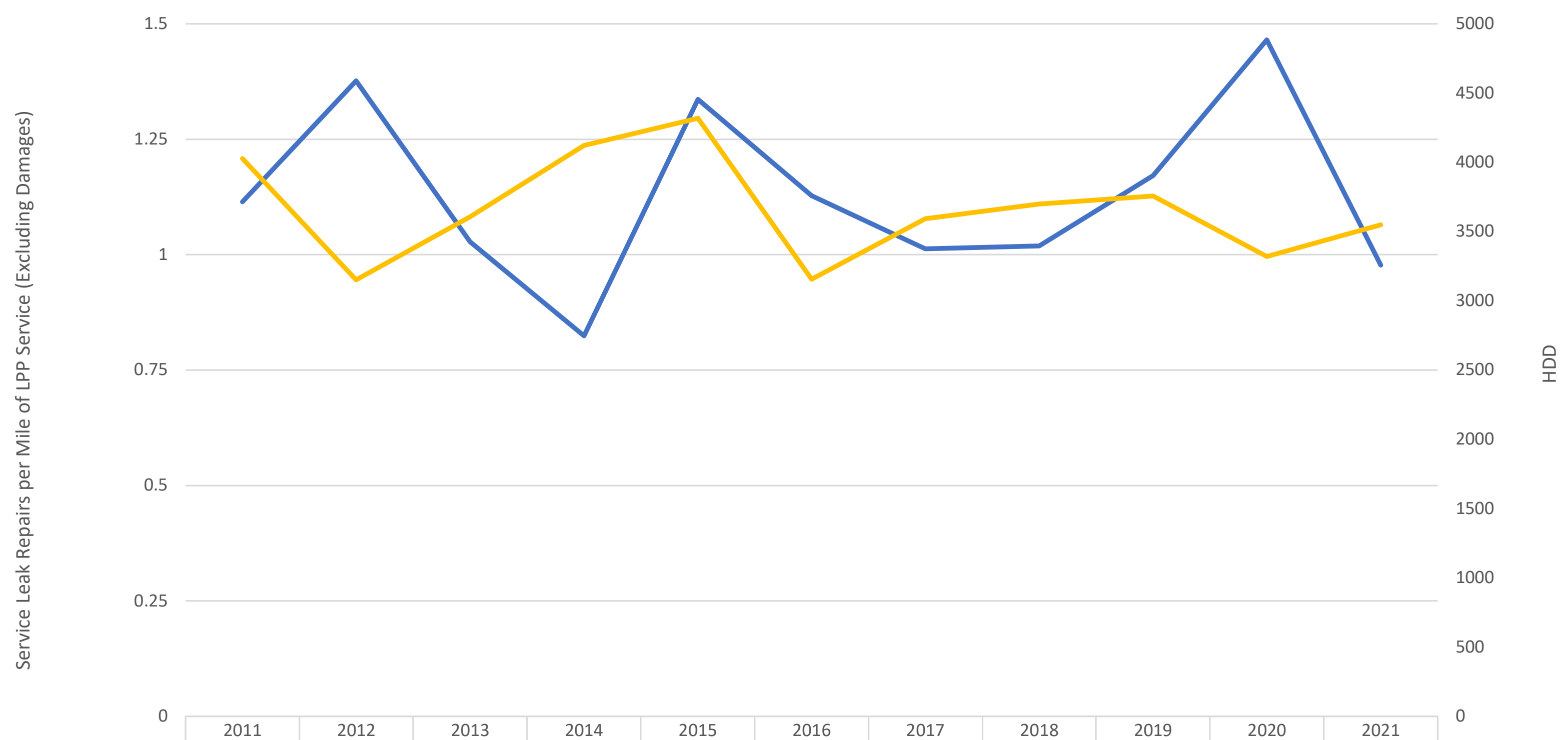
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
LPP - Mains and Services Combined (Miles)	2182	2096	2015	1938	1841	1761	1662	1644	1546	1531	1464
Leak Receipts per Mile of LPP - Mains and Services Combined	1.15	1.15	1.12	1.42	1.19	0.88	1.16	1.21	1.36	1.14	1.03
HDD	4026	3151	3608	4123	4318	3156	3593	3699	3757	3319	3549

Leak Receipts per Mile of LPP - Mains and Services Combined　HDD



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
LPP Main (Miles)	1471	1409	1355	1305	1237	1186	1140	1100	1052	989	942
Main Leak Repairs per Mile of LPP Main (Excluding Damages)	1.12	1.13	0.79	0.91	0.58	0.62	0.74	0.84	0.92	0.74	0.82
HDD	4026	3151	3608	4123	4318	3156	3593	3699	3757	3319	3549

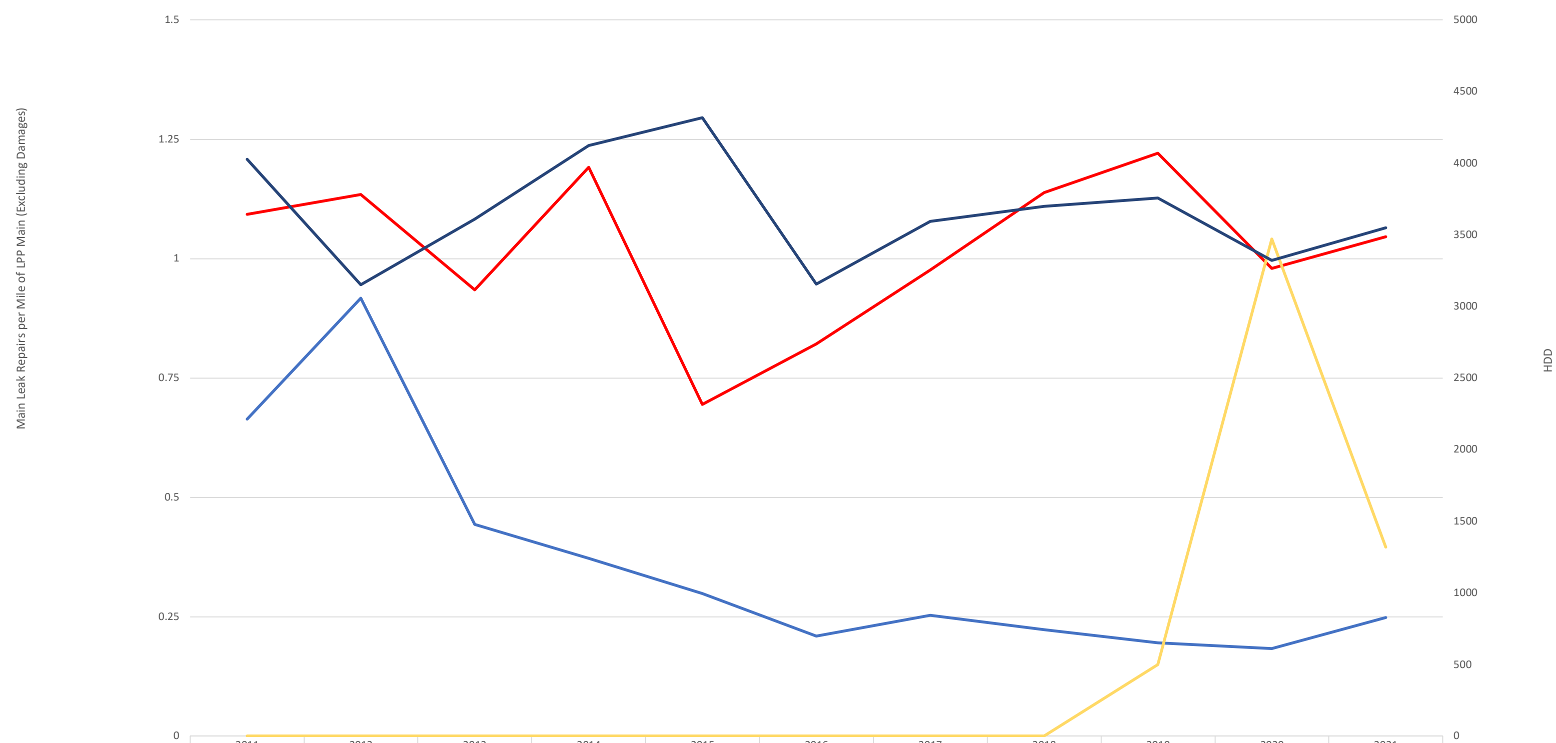
Service Leak Repairs per Mile of LPP Service (Excluding Damages)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
LPP Service Inventory (Miles)	711	687	660	633	604	575	560	544	532	542	522
Service Leak Repairs per Mile of LPP Service (Excluding Damages)	1.11	1.38	1.03	0.82	1.34	1.13	1.01	1.02	1.17	1.46	0.98
HDD	4026	3151	3608	4123	4318	3156	3593	3699	3757	3319	3549

Service Leak Repairs per Mile of LPP Service (Excluding Damages) HDD

Main Leak Repairs per Mile of LPP Main (Excluding Damages)
Cast Iron, Unprotected Steel, and Ductile Iron



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Miles of Cast Iron Main	875	859	831	806	769	754	730	700	690	660	632
Cast Iron Main Leak Repairs per Miles of Cast Iron Main	1.09	1.13	0.93	1.19	0.69	0.82	0.98	1.14	1.22	0.98	1.05
Miles of Unprotected Steel Main	580	534	508	483	452	416	395	386	349	316	298
Unprotected Steel Main Leak Repairs per Miles of Unprotected Steel Main	0.66	0.92	0.44	0.37	0.30	0.21	0.25	0.22	0.20	0.18	0.25
Miles of Ductile Iron Main	17	16	16	16	16	16	16	14	13	13	13
Ductile Iron Main Leak Repairs per Miles of Ductile Iron Main	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	1.04	0.40
HDD	4026	3151	3608	4123	4318	3156	3593	3699	3757	3319	3549

Cast Iron Main Leak Repairs per Miles of Cast Iron Main   Unprotected Steel Main Leak Repairs per Miles of Unprotected Steel Main   Ductile Iron Main Leak Repairs per Miles of Ductile Iron Main   HDD

PUC 4-2
Leak Prone Pipes (LPP)

Request:

Have any elements of ENG04030 changed in the past year (other than rebranding)? Does RIE anticipate any future changes as a result of the sale of TNEC to PPL? Does RIE continue to use DNV's Synergi software for management of the LPP and the proactive replacement program?

Response:

Rebranding was the only revision to ENG04030 in the past year. The last revision prior to that was in February of 2022, where the section on evaluating Non-Pipeline Alternatives (NPA) was added under Section 5.2 j.

The Company will continue to follow ENG04030 until its new risk model, which is under development, is implemented. The new model, called JANA, will evaluate the Company's entire system as explained in PUC 3-6. The model is projected to be completed in October 2023. The Company will run the new model concurrently with ENG04030 until it is able to fully transition to the JANA model. The transition is expected in 2024, at which time the Company will update ENG04030 to reflect the JANA model.

The Company does not use DNV's Synergy software to evaluate risk. The Synergy software used is for system-wide hydraulic modeling of various flows and pressure under load.

PUC 4-3
Leak Prone Pipes (LPP)

Request:

Referring to the Rebuttal Testimony of Kocon & Hunt at page 22 of 37, lines 9-10, please provide a copy of any guidelines or other document that the Company uses for the implementation of its Distribution Integrity Management Program when the Company prioritizes the riskiest leak-prone pipes for replacement.

Response:

Please see Attachment PUC 4-3 entitled "Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement ENG04030."

Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement ENG04030

1. Purpose

This procedure describes and details the identification, evaluation, and prioritization of distribution main segments for replacement, and prescribes methods to be used for corrective action.

Potential areas of active corrosion are identified using leakage surveys in conjunction with an analysis of the corrosion and leak history records.

2. Responsibilities

Distribution Engineering or designee shall be responsible for:

- Serving as Process Owner / Lead Organization for this policy document.
- Gathering and evaluating gas facility and leak data and determine required calculations.
- Determining qualification and prioritization procedure and remedial action for active corrosion, non-active continuing corrosion, and other systemic integrity issues.
- Identifying main segments for replacement and prioritizing them according to this procedure.

Corrosion Engineering or designee shall be responsible for:

- Evaluating and reclassifying pre-1971 gas piping with cathodic protection (CP).

3. Personal & Process Safety

All required PPE shall be worn or utilized in accordance with the current Rhode Island Energy Safety Policy when performing tasks associated with this document.

4. Operator Qualification Required Tasks [Qualified or Directed & Observed]

Not applicable.

5. Content

5.1 Identification of Main Segments for Replacement

a. Main segment candidates are identified through four avenues:
   1) Field Requests, which will be reviewed throughout the year.
   2) Mains located in Public Improvement Job Areas, which will also be reviewed throughout the year, as requested by Field Operations and/or Public Works employees.
   3) Annual screenings by Main and Service Engineering, as deemed appropriate. Screenings will vary among the regions, based on the data and tools available for the systems.
   4) Lab failure analysis reports reviewed by Distribution Engineering for systemic issues.

b. All identified main segment candidates shall be evaluated and prioritized by Distribution Engineering in accordance with the criteria set forth in this procedure. Minimum segment lengths for screening and engineering review will vary among the regions; however, no Engineering review is required for replacements up to 300 feet. Segments identified by Distribution Engineering for systemic integrity issues will be replaced and prioritized as determined appropriate.

c. Where possible, the system should be upgraded to high pressure while retiring low pressure mains.

d. Leak prone pipe replacement includes replacement of associated leak prone services listed below:
   1) All steel services except large diameter, industrial and commercial services with CP
      **Note: Services that cannot be relayed should be transferred and follow corrosion policies. A test station sketch should be sent to corrosion department.
   2) Plastic
      i. Pre-1985: Aldyl-A (usually pink or grey)
      ii. Pre-1974: HDPE (black)
      iii. Polybutylene (PB) - (tan or yellow)
   3) Copper
   4) Cast Iron
   5) Wrought Iron

e. Large diameter remediation includes Lining and CISBOT of leak prone steel mains and cast iron mains greater than 12 inches in diameter
   1) Lining and replacement are the preferred remediation methods. Lining is not possible when there are too many services or there is presence of mitered bends or back-to-back 45s or main cannot be taken out of service (require expensive bypass), or main is too deep. CISBOT will be used when lining is not feasible.

f. All identified main segment candidates shall be reviewed by Distribution Engineering with Corrosion Engineering to ensure that none of the job or part of the job is pre 1971 protected main.

5.2 Evaluation/Prioritization of Steel Main Segments for Replacement

a. Data Collection - Minimum Data Required:
   1) All Repaired Corrosion Leaks on Main Segment for the last 10 years
   2) All repaired corrosion leaks on services for last 10 years. (In order to consider service leaks in main prioritization calculation, there should be main leaks)
   3) All Open Leaks that are believed to be on the actual Main Segment

b. For all applicable leaks, the following data is required:
   1) Leak Number
   2) Date (date found for open leaks, date repaired for repaired leaks)
   3) Leak Class (original class for open leaks, repaired class for repaired leaks)
   4) For repaired leaks, the following additional data is also required:
      i. Number of clamps installed to repair and specific clamp locations.
      ii. Condition of main when repaired.
      iii. Address based leak location.
      iv. Length of segment exhibiting significant leak activity (i.e., from first leak to last leak).
      v. Building Types in Area of Main Segment (None, Single Family Houses, Small Buildings, Public Buildings).

c. Calculate a main deterioration factor (“D”) using the formula:

$$D = N \times 500 / L_{(calc)}$$

Where:

$L_{(calc)}$ = Length of Segment exhibiting significant leak activity (i.e., first leak to last leak) or 500 feet, whichever is larger. However, if the total length of the segment considered for replacement is less than 500 feet, Lcalc shall be the length of the main considered,

The segment length used in calculations is not necessarily the total length being considered for replacement. "L" should be determined by the evaluating engineer as the length of the segment exhibiting significant leak activity. In no case should the length used for calculations extend beyond the locations of the leaks).

and

N = Repair Factor (within the defined "L_{calc}").

1) If the leak is still open (except for grade 3 high emitter leaks), N=1 for each open leak.
2) If the leak is still open and is a grade 3 high emitter leak, N=2 for each open leak.
3) If leak was repaired with 1 clamp, by another method or associated with service corrosion leak repair, N = 1.
4) If the leak was repaired with 2 – 3 clamps, N = 2.
5) If the leak was repaired with 4 – 5 clamps, N = 3.
6) If the leak was repaired with 6 – 7 clamps, N = 4.
7) If the leak was repaired with > 7 clamps, N = 5.
8) If the leak was repaired by replacing a section of a pipe less than 10', N=7 and N=9 for replacement pipe 10' or greater.

THE SUM OF ALL THE "N"s FOR EACH LEAK IS PLUGGED INTO THE FORMULA

This method estimates the deterioration according to the actual number of physical repairs and normalizes it for the length of the segment.

d. Calculate an incident probability factor ("P") using the formula:

P = {[(# Class1 Leaks/0.5) + (# Class2A Leaks/1.5) + (# Class2 Leaks/2) + (# Class3 Leaks/3)] x 500} / $L_{(calc)}$

This method estimates public safety incident probability by weighting each leak based on how far the gas migrated toward buildings, again normalized according to the segment length. (Note – If leak class is unknown, Class 2A will be assumed).

e. Calculate a risk factor ("R") using the formula:

R = P x C

Where:

P = Probability Factor Calculated in previous step.
C = Consequence Factor

1) If there are no buildings in the area, C = 0.
2) If there are only single-family homes, C = 1.

3) If there are small buildings (multi-family, strip mall, etc.), C = 1.2.
4) If there are public buildings (school, church, hospital, etc.) C = 1.5.

This is the standard Risk Analysis calculation where Risk is defined as the product of the likelihood of an event and the potential consequence of that event. Consequences increase with building size and number of people affected.

f. Calculate the preliminary prioritization factor (“Pr”) using the formula:

Pr = D + R + IM

Where:

D = Deterioration Factor Calculated in “c”.
R = Risk Factor Calculated in “e”.
IM = DIMP factor as found in Rhode Island Energy’s Distribution Integrity Management Program (DIMP) listed in attachment 1

The prioritization calculation considers both the deterioration of the main and the risk to public safety.

IM factor is applied to help accelerate the attrition of mains which belong to an asset group known to have a higher likelihood of incident or is of a high relative risk.

g. The following adjustments may be needed:

1) Before making a final determination and prioritization of a main segment replacement, the details of the job are reviewed and “engineering judgment” is applied where appropriate. This application may result in the following types of adjustments:
   i. Changing the priority of the job
   ii. Increasing or decreasing the job length/scope
   iii. Breaking the job into smaller segments
   iv. Merging several segments into one job
2) These adjustments may be made based on the following types of information, if available and applicable:
   i. Analysis of the age of the leaks and any increasing frequency of leak occurrences
   ii. Pipe vintage and service insert activity associated with the main
   iii. Service leaks at the main connection due to corrosion
   iv. Adjustments based on very long or very short segments
   v. Observed pipe condition from leak repair data
   vi. Observed pipe condition from recent field exposure
   vii. Clustering of repairs and/or clamps along the segment
   viii. Other replacement jobs in the vicinity
   ix. Cathodic protection systems in place
   x. Specific locations of intersections, fittings, material transitions, diameter transitions, etc.
   xi. Customer complaints, Executive complaints, Regulatory Agency complaints
   xii. Corporate good will

- xiii. Unusual hazards or exposure in the area
- xiv. Proximity to gas regulating equipment
- xv. Proximity to transmission main
- xvi. Unusual difficulty or expense of repairs
- xvii. Main location
- xviii. Identification of outdated construction methods or problematic materials or fittings
- xix. Depth of cover and soil conditions
- xx. High open leak counts
- xxi. Water intrusion or other geographic considerations
- xxii. Any special or unusual conditions or considerations identified by Field Operations
- xxiii. Any other safety, integrity, operational or economic factors that are available and deemed appropriate

Segments that qualify based on their preliminary prioritization calculation may not be disqualified by adjustments.

h. Qualification of job for replacement:

1) Jobs will be approved and prioritized based on the calculated Prioritization Factor (“Pr”) and applied adjustments. Enough jobs should be approved to accommodate the replacement levels determined by the model(s) in use at the time.

Some jobs will be mandatory to replace.

2) In general, a condition of “Active Corrosion” will be determined when the preliminary Pr calculation is greater than 20 (Pr > 20).
3) Use the following labels for each job to provide a macro view as to the type of work to be performed throughout the year.
   - i. A “TS 300” label is associated with any steel job with a preliminary Prioritization Factor (“Pr”) calculation of greater than 20 (Pr > 20), known as “Active Corrosion.”
   - ii. A TS 900 label is given to any job which has received additional points from Public Works considerations (as described below).
   - iii. A TS 800 label is given to the remainder of the jobs.

i. Impact Identification:

1) Every approved job should be processed through the Strategic Asset and System Planning and Corrosion Engineering for:
   - i. Sizing (determining the appropriate replacement material and diameter).
   - ii. Determining if the replacement will have any impact on existing cathodic protection systems.
   - iii. Determining if abandonment is an appropriate option over replacement.
   - iv. Determining if a system uprating is an appropriate option as part of the replacement.

j. Non-Pipeline Alternative Evaluation (NPA):

1) All jobs will be evaluated for NPA feasibility. If NPA is not feasible, reason(s) will be provided.

5.3 Evaluation/prioritization of cast iron main segments for replacement

a. Cast Iron Main Segments will be evaluated in a similar manner as Steel Main segments, where the Prioritization factor will be the sum of the Deterioration Factor, Risk factor and DIMP factor (Pr = D + R + IM).

b. Candidates are reviewed based primarily on breakage and/or graphitization history; and all segments that contain 1or more breaks and/or graphitization repairs must be reviewed.

c. If the candidate segment has had two (2) or more breaks and/or graphitization repairs within 400 feet. and the MAOP is greater than six inches of water column – the segment has automatic approval for replacement. The Prioritization score will automatically be set at 21.

d. If the candidate segment doesn't have at least 2 breaks and/or graphitization repairs or if the pressure is six inches of water column– approval will be based on the Prioritization calculation

   i. If "Pr" is greater than 20 (Pr > 20), replacement will be required (however, a cast iron segment is not deemed active corrosion)

   ii. If "Pr" is less than or equal to 20 (Pr ≤ 20), prioritize and replace according to resources and replacement level recommendations

e. The Repair Factor "N" (as defined 5.2 – c for steel evaluation), will be assigned for each leak, as follows:

1) For cast iron – main breaks, graphitization (corrosion of cast iron) and joint leak repairs are examined.

   i. If the leak is still open or associated service corrosion leak repair, N = 1.

   ii. If the leak was repaired only by joint sealing, N = 0.5.

   iii. If the leak was a break, crack or graphitization, N = 3.

f. Engineering judgment should also be applied to both the prioritization and determination of the segment length to be replaced based on the pressure, diameter, dates of failures, surrounding areas, etc.

5.4 Evaluation/prioritization of plastic main segments for replacement

a. Vintage Plastic Main Segments shall be evaluated by Distribution Engineering based on Lab Failure Analysis Reports that are reviewed for systemic issues.

   I. If Distribution Engineering determines that a systemic issue exists in a specific main segment due to improper fusion or other construction defects, the entire affected section of main will be forwarded to Main and Service Replacement Group for prioritization and expedited replacement.

b. Plastic Main Segments (including non-vintage plastic) will be evaluated in a similar manner as Steel Main segments, where the Prioritization factor will be the sum of the Deterioration Factor, Risk factor and DIMP factor (Pr = D + R + IM).

c. For plastic pipe segments in "b", above, the following criteria shall apply:

   1) For plastic – Previous squeeze-offs, point loading failures (e.g. – rock impingement) and material defects (e.g. – cracking) and construction defect failures (e.g. – butt fusion joint) are examined.

      Where:

N = Repair Factor (within the defined "L")

i. If the leak is still open, N = 1
ii. If the leak was the result of an improper squeeze-off, N = 2 x (the number known squeeze-offs on ALDYL-A pre 1985 pipe)
iii. If the leak was the result of a point loading failure, N = 2
iv. If the leak was the result of a construction defect or material defect, N = 3

5.5 Evaluation and Reclassification of Pre-1971 Gas Piping with Cathodic Protection

a. The following factors should be considered in evaluating and reclassify Pre-DOT CP pipe:
   1) The Corrosion Engineering department shall identify inadequately protected sections of mains and services on the basis of:
      i. Frequently failed readings in the last 5 years
      ii. Failed readings despite additional anode installation
      iii. Unusually low resistance or high current demand as determined by Corrosion Control
      iv. Excessive Coating degradation determined by integrity assessments
      v. High corrosion leak activity
      vi. Any other unusual or abnormal condition determined by Corrosion Control

   2) The section identified in section 1 above shall be removed from the CP monitoring program. The Electronic Monitoring Database and the Corrosion Control section folders shall be updated accordingly. In PCS, the section shall be marked as "inactive" and a statement that the section has been removed from the CP monitoring program along with an effective date with explanation of reclassification will be provided in the permanent remarks section. Reclassified pipe will be marked as "removed from CP" where Electronic Monitoring Database is available.
   3) Once the section is removed from the CP monitoring program, it shall be treated as unprotected coated/bare main.
   4) Every six months, the Corrosion Engineering department will run a report listing which sections of pipe have been reclassified from CP to unprotected coated/bare main. The Corrosion Engineering department will check this list against Corrosion Control mapping records to ensure consistency. This list will be sent to the Distribution Engineering.

b. The following steps are used to evaluate and reclassify Pre-DOT CP pipe when Distribution Engineering or field employees identify inadequacies:
   1) Distribution Engineering shall consult with the Corrosion Engineering department to evaluate the effectiveness of the cathodic protection on the section identified. Corrosion Engineering department will evaluate the section of main based on section 1 above.
      i. Distribution Engineering shall incorporate the reclassified unprotected coated/bare main section into the LPP main replacement program on the basis of priority.

5.6 Reinforcements, Jobs in Public Works Areas, or Storm Hardening

a. Additional adjustment shall be applied for candidate segments in flood zones – by the addition of a storm hardening factor to the Prioritization calculation. An exception to the flood zone factor may be applied. Any exception to the flood zone factor shall be documented as part of the prioritization calculation.

b. Additional adjustments may be applied for candidate segments in public works areas or for which reinforcement opportunities have been identified - by the addition of a Public Works (PW) and/or Reinforcement (RI) factor to the Prioritization calculation:

$$Pr = D + R + IM + PW + RI + SH$$

1) For Road Resurfacing, PW = 2.4
2) For Road Reconstruction, PW = 4.2
3) For Size-Pressure Upgrade Reinforcement, RI = 2.5
4) For 100-yr FEMA defined flood zone, SH = 2
5) For 500-yr FEMA defined flood zone, SH = 1

These factors are applied because of potential cost savings in combining main replacements with other work, as well as anticipated avoidance of performing work on protected streets that were recently improved.

6. References

Code	Section	Description
49 CFR	192.457	External corrosion control: Buried or submerged pipelines installed before August 1, 1971

7. Attachments

Attachment 1: ENG04030 Attachment 1 DIMP factors

PUC 4-4
Leak Prone Pipes (LPP)

Request:

With reference to RIE's response to Division 1-15:

a. Please explain if "risk ranked" refers to calculating a Risk Factor, a Deterioration Factor, a DIMP Factor, a Prioritization Factor, or all of these.

b. Please reproduce the response but include a column that indicates the number of miles of LLP main inventory that is not risk ranked in each city and town.

c. Please provide if and when the entire inventory will be risk-ranked.

Response:

a. Risk ranked means that a priority score has been calculated using the ENG04030 procedure and assigned to the segment/scope of work in question. Once a segment (and surrounding scope) is analyzed, it remains in the Company's analyzed inventory until the project is completed/abandoned.

b. Please see Attachment PUC 4-4.

c. The Company is currently in the process of building out a risk management model with JANA, which will be able to evaluate risk throughout the entire system. The expected delivery for this model is October 2023. Once delivered, the Company will run the JANA model alongside ENG04030 until the Company is confident in the data the JANA model is providing, at which time the ENG04030 method of prioritization will be retired. This is anticipated in 2024. For further background on the JANA model, please refer to the Company's response to Data Request Division 3-6.

Prepared by or under the supervision of: Corey Hogg

Numbers in table represent analyzed main inventory as of 03/07/2023. In progress projects are included in totals until abandonment is completed.

LPP inventory data accurate as of 02/22/2023

Municipality	Total miles of leak-prone pipe currently in place	Total miles of leak-prone pipe not currently included in analyzed inventory	High $Pr \geq 15$	Medium $10 \leq Pr \leq 15$	Low $Pr < 10$
Barrington	1.46	0.00	0.00	0.00	1.46
Bristol	10.87	3.91	1.02	3.91	2.03
Burrillville	0.00	0.00	0.00	0.00	0.00
Central Falls	20.09	11.40	0.00	1.45	7.24
Coventry	10.15	2.33	0.00	0.00	7.82
Cranston	107.74	64.28	5.10	9.13	29.23
Cumberland	26.38	19.59	1.03	1.06	4.70
East Greenwich	5.67	4.00	0.03	0.00	1.64
East Providence	44.68	23.57	3.82	4.17	13.12
Exeter	0.31	0.31	0.00	0.00	0.00
Hopkinton	0.02	0.00	0.00	0.00	0.02
Johnston	31.50	13.88	0.89	1.88	14.85
Lincoln	14.68	5.44	1.60	1.36	6.28
Middletown	4.31	1.55	0.00	0.53	2.23
Narragansett	0.52	0.00	0.00	0.00	0.52
Newport	17.36	9.13	1.62	1.45	5.16
North Kingstown	6.48	3.42	0.00	0.00	3.06
North Providence	44.16	25.18	6.51	3.21	9.26
North Smithfield	7.01	1.18	1.32	0.85	3.66
Pawtucket	141.27	108.35	7.15	10.01	15.76
Portsmouth	0.05	0.05	0.00	0.00	0.00
Providence	211.58	125.35	34.95	24.81	26.47
Scituate	0.00	0.00	0.00	0.00	0.00
Smithfield	6.72	2.17	1.55	0.00	3.00
South Kingstown	8.71	4.01	0.00	0.00	4.70
Tiverton	0.00	0.00	0.00	0.00	0.00
Unknown	11.40	11.40	N/A	N/A	N/A
Warren	2.00	0.54	0.00	0.56	0.90
Warwick	68.02	32.77	2.48	2.37	30.40
West Greenwich	0.00	0.00	0.00	0.00	0.00
West Warwick	17.73	12.73	0.00	0.00	5.00
Westerly	8.13	2.45	1.80	1.90	1.98
Woonsocket	48.43	26.00	2.98	4.92	14.53

PUC 4-5
Leak Prone Pipes (LPP)

Request:

Please provide a table with high, medium, and low priority scores as in RIE's response to Division 1-15, but instead of rows that indicate towns, please have rows that indicate the prioritization score of mains that were actually replaced during that year's ISR FY plan (or CY, if that is easier to organize). Please also include a row for the 53 miles of planned Proactive Main Replacement & Rehabilitation (Proactive Main Program) in the Supplemental FY 24 Forecast.

Response:

Please see Attachment PUC 4-5 for the abandonment mileage completed as a part of the Proactive Main Replacement Program for FY 2020 through FY 2023 as well as the proposed abandonment mileage to be done for FY 2024, separated by priority score tier (mirroring the prior response referenced). Please note, the actual abandonment mileage for FY 2023 (through March 7th, 2023) and the proposed mileage for FY 2024 conveyed in this response are accurate as of March 7th, 2023. The proposed work/material mix for FY 2024 is subject to change.

Prepared by or under the supervision of: Corey Hogg

*FY23 actuals are accurate as of 03/07/2023.

**FY24 Proactive Main Replacement Program planned mileage totals are accurate as of 03/07/2023 and are subject to change.

Proactive Main Replacement Program
Actual Abandonment Mileage for FY20 through FY23 and Planned Abandonment Mileage for FY24
Sorted by Priority Score Tiers

FY	High Pr ≥ 15	Medium 10 ≤ Pr ≤ 15	Low Pr < 10	Total
20	14.48	7.02	26.39	47.89
21	6.12	3.43	12.66	22.21
22	24.92	15.66	11.73	52.31
23*	19.50	12.35	12.80	44.65
24**	25.35	12.29	14.81	52.45

PUC 4-6
Leak Prone Pipes (LPP)

Request:

Please provide a table with rows of years and columns of miles of leak prone pipe actually remediated through the Proactive Main Program organized by risk score in bin sizes of 1. Please plot the data in a stacked bar graph so that each year is a difference color or shade.

Response:

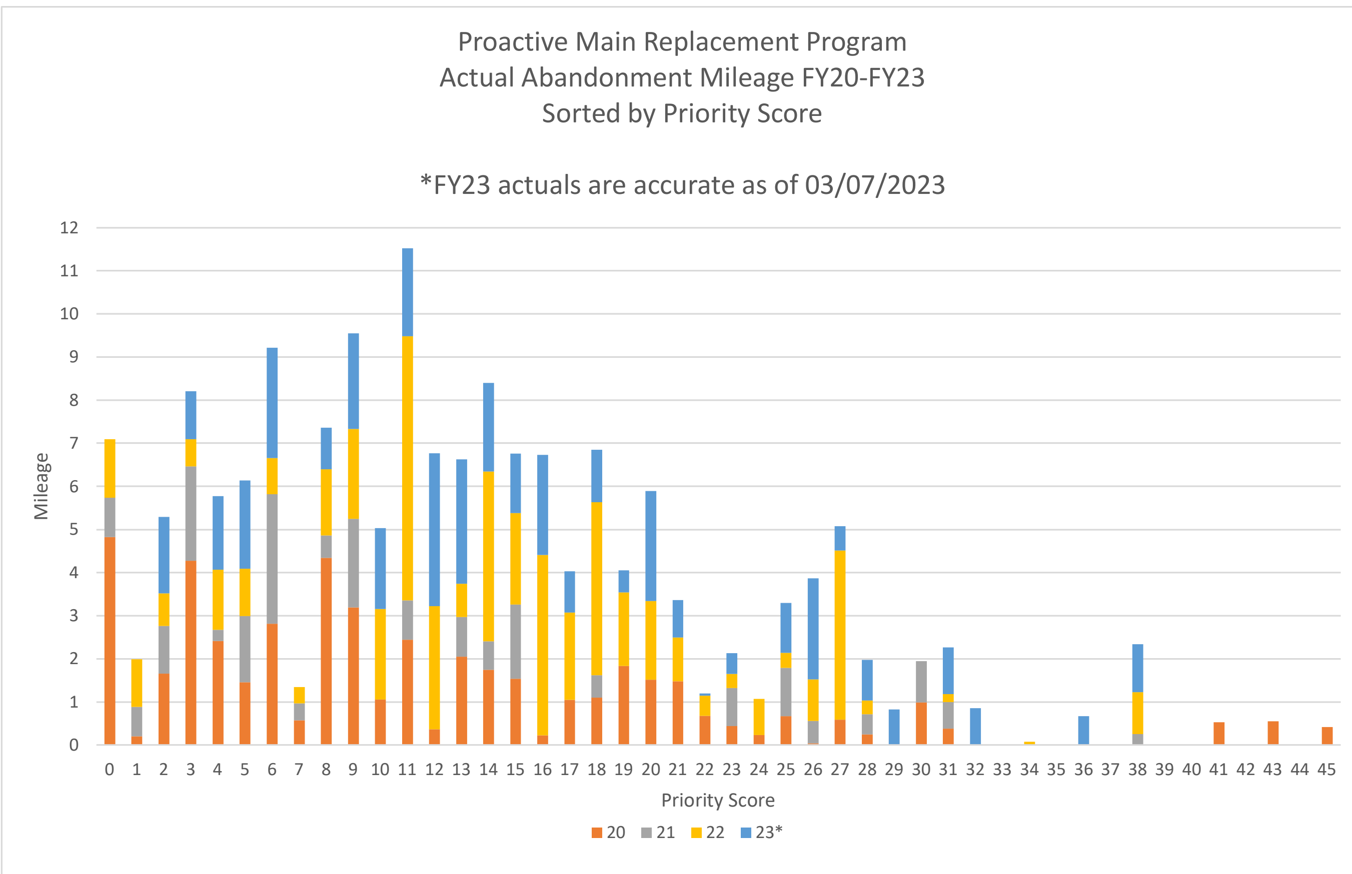
Please see Attachments PUC 4-6-1 and PUC 4-6-2 for the requested information in table and stacked bar graph format for FY 2020 through FY 2023. Please note, FY 2023 actuals are accurate as of 03/07/2023.

Prepared by or under the supervision of: Corey Hogg

*FY23 actuals are accurate as of 03/07/2023.

Proactive Main Replacement Program
Actual Abandonment Mileage FY20-FY23
Sorted by Priority Score

	Fiscal Year			
Priority	**FY20**	**FY21**	**FY22**	**FY23***
0	4.82	0.92	1.35	0.00
1	0.20	0.69	1.10	0.00
2	1.66	1.10	0.76	1.77
3	4.28	2.19	0.63	1.11
4	2.41	0.26	1.39	1.71
5	1.46	1.54	1.10	2.05
6	2.81	3.01	0.84	2.55
7	0.57	0.39	0.39	0.00
8	4.34	0.52	1.53	0.96
9	3.19	2.06	2.08	2.22
10	1.06	0.00	2.10	1.88
11	2.45	0.91	6.13	2.03
12	0.37	0.00	2.85	3.55
13	2.05	0.92	0.77	2.88
14	1.75	0.66	3.94	2.05
15	1.53	1.73	2.12	1.38
16	0.22	0.00	4.19	2.32
17	1.05	0.00	2.02	0.96
18	1.10	0.52	4.02	1.22
19	1.83	0.00	1.71	0.51
20	1.52	0.00	1.82	2.56
21	1.48	0.00	1.02	0.87
22	0.68	0.00	0.47	0.05
23	0.44	0.88	0.33	0.48
24	0.24	0.00	0.83	0.00
25	0.66	1.13	0.34	1.16
26	0.04	0.52	0.97	2.35
27	0.58	0.00	3.93	0.57
28	0.25	0.47	0.32	0.93
29	0.00	0.00	0.00	0.83
30	0.99	0.96	0.00	0.00
31	0.38	0.61	0.19	1.08
32	0.00	0.00	0.00	0.85
33	0.00	0.00	0.00	0.00
34	0.00	0.00	0.08	0.00
35	0.00	0.00	0.00	0.00
36	0.00	0.00	0.00	0.67
37	0.00	0.00	0.00	0.00
38	0.00	0.25	0.98	1.11
39	0.00	0.00	0.00	0.00
40	0.00	0.00	0.00	0.00
41	0.52	0.00	0.00	0.00
42	0.00	0.00	0.00	0.00
43	0.55	0.00	0.00	0.00
44	0.00	0.00	0.00	0.00
45	0.42	0.00	0.00	0.00


Proactive Main Replacement Program
Actual Abandonment Mileage FY20-FY23
Sorted by Priority Score
*FY23 actuals are accurate as of 03/07/2023
Mileage
0
1
2
3
4
5
6
7
8
9
10
11
12
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45
Priority Score
20
21
22
23*

PUC 4-7
Leak Prone Pipes (LPP)

Request:

Please provide the same as 4-6, but for the initial Prioritization Factor, if known. If not, please provide the final Prioritization factor, if known.

Response:

The data set provided in the Company's response to PUC 4-6 (both the table and the chart) includes the available prioritization scores. Records are only kept for the last calculated priority score before a segment is abandoned.

Prepared by or under the supervision of: Corey Hogg

PUC 4-8
Leak Prone Pipes (LPP)

Request:

Please provide the same as 4-6, but for only cast iron mains.

Response:

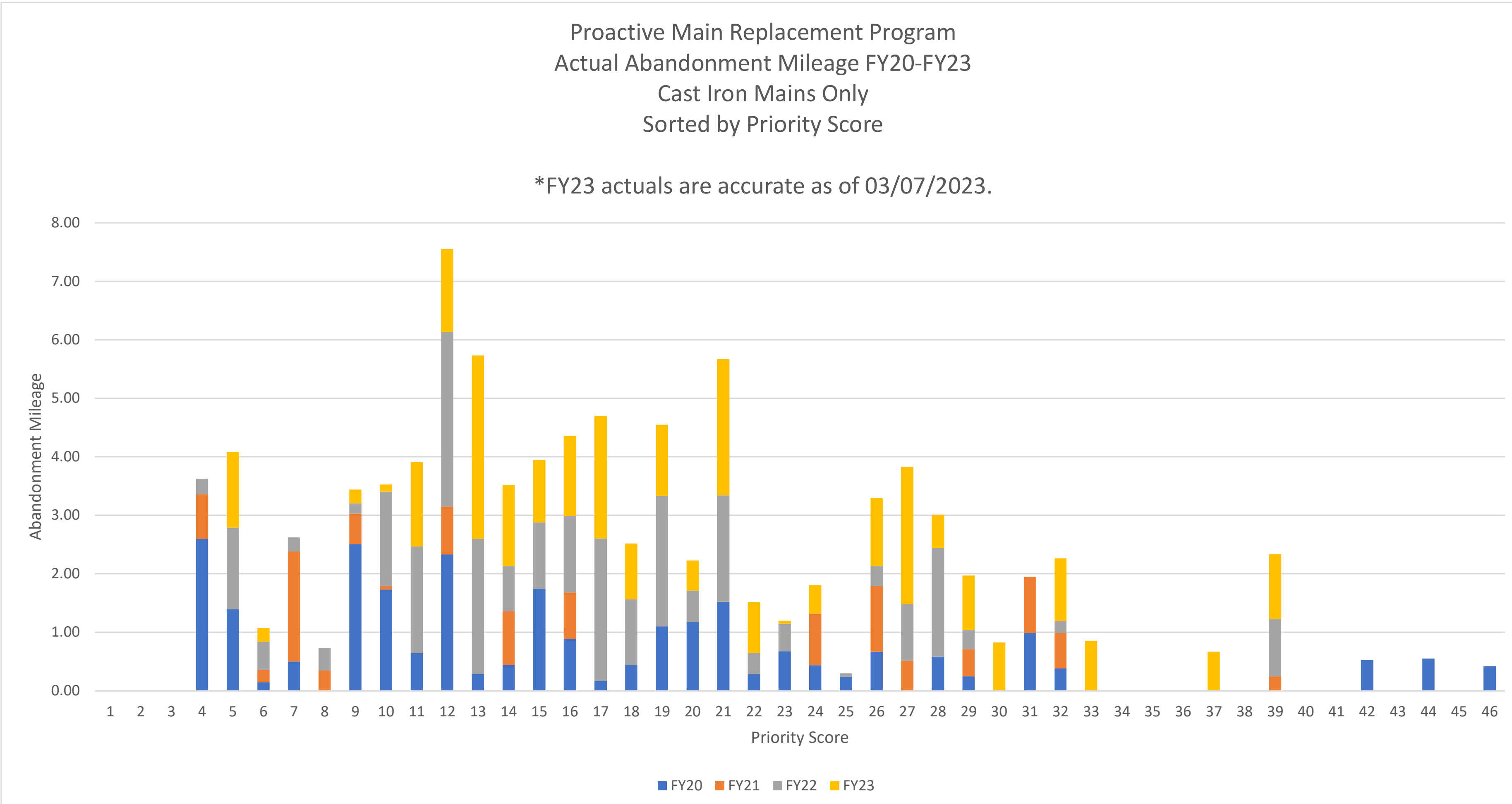
Please see Attachments PUC 4-8-1 and PUC 4-8-2 for the requested information in table and stacked bar graph format for FY20 through FY23. Please note, FY23 actuals are accurate as of 03/07/2023.

Prepared by or under the supervision of: Corey Hogg

*FY23 actuals are accurate as of 03/07/2023.

Proactive Main Replacement Program
Actual Abandonment Mileage FY20-FY23
Cast Iron Mains Only
Sorted by Priority Score

	Fiscal Year			
Priority	**FY20**	**FY21**	**FY22**	**FY23***
0	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00
3	2.59	0.76	0.27	0.00
4	1.40	0.00	1.39	1.29
5	0.15	0.21	0.48	0.24
6	0.50	1.88	0.24	0.00
7	0.00	0.35	0.39	0.00
8	2.51	0.52	0.18	0.23
9	1.73	0.06	1.62	0.12
10	0.65	0.00	1.82	1.45
11	2.33	0.82	2.99	1.42
12	0.29	0.00	2.31	3.14
13	0.44	0.92	0.77	1.38
14	1.75	0.00	1.13	1.07
15	0.89	0.79	1.30	1.38
16	0.17	0.00	2.43	2.10
17	0.45	0.00	1.11	0.96
18	1.10	0.00	2.23	1.22
19	1.18	0.00	0.53	0.51
20	1.52	0.00	1.82	2.33
21	0.28	0.00	0.36	0.87
22	0.68	0.00	0.47	0.05
23	0.44	0.88	0.00	0.48
24	0.24	0.00	0.06	0.00
25	0.66	1.13	0.34	1.16
26	0.00	0.52	0.97	2.35
27	0.58	0.00	1.86	0.57
28	0.25	0.47	0.32	0.93
29	0.00	0.00	0.00	0.83
30	0.99	0.96	0.00	0.00
31	0.38	0.61	0.19	1.08
32	0.00	0.00	0.00	0.85
33	0.00	0.00	0.00	0.00
34	0.00	0.00	0.00	0.00
35	0.00	0.00	0.00	0.00
36	0.00	0.00	0.00	0.67
37	0.00	0.00	0.00	0.00
38	0.00	0.25	0.98	1.11
39	0.00	0.00	0.00	0.00
40	0.00	0.00	0.00	0.00
41	0.52	0.00	0.00	0.00
42	0.00	0.00	0.00	0.00
43	0.55	0.00	0.00	0.00
44	0.00	0.00	0.00	0.00
45	0.42	0.00	0.00	0.00


Proactive Main Replacement Program
Actual Abandonment Mileage FY20-FY23
Cast Iron Mains Only
Sorted by Priority Score
*FY23 actuals are accurate as of 03/07/2023.
Abandonment Mileage
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46
Priority Score
FY20
FY21
FY22
FY23

PUC 4-9
Leak Prone Pipes (LPP)

Request:

Please provide the same as 4-6, 4-7, and 4-8, but for the FY 24 Forecast.

Response:

Please see Attachments PUC 4-9-1 and PUC 4-9-2 for the requested information in table and bar graph format for the FY24 forecasted abandonment to be completed under the Proactive Main Replacement program. Please note, FY24 Proactive Main Replacement Program planned mileage totals are accurate as of 03/07/2023 and are subject to change.

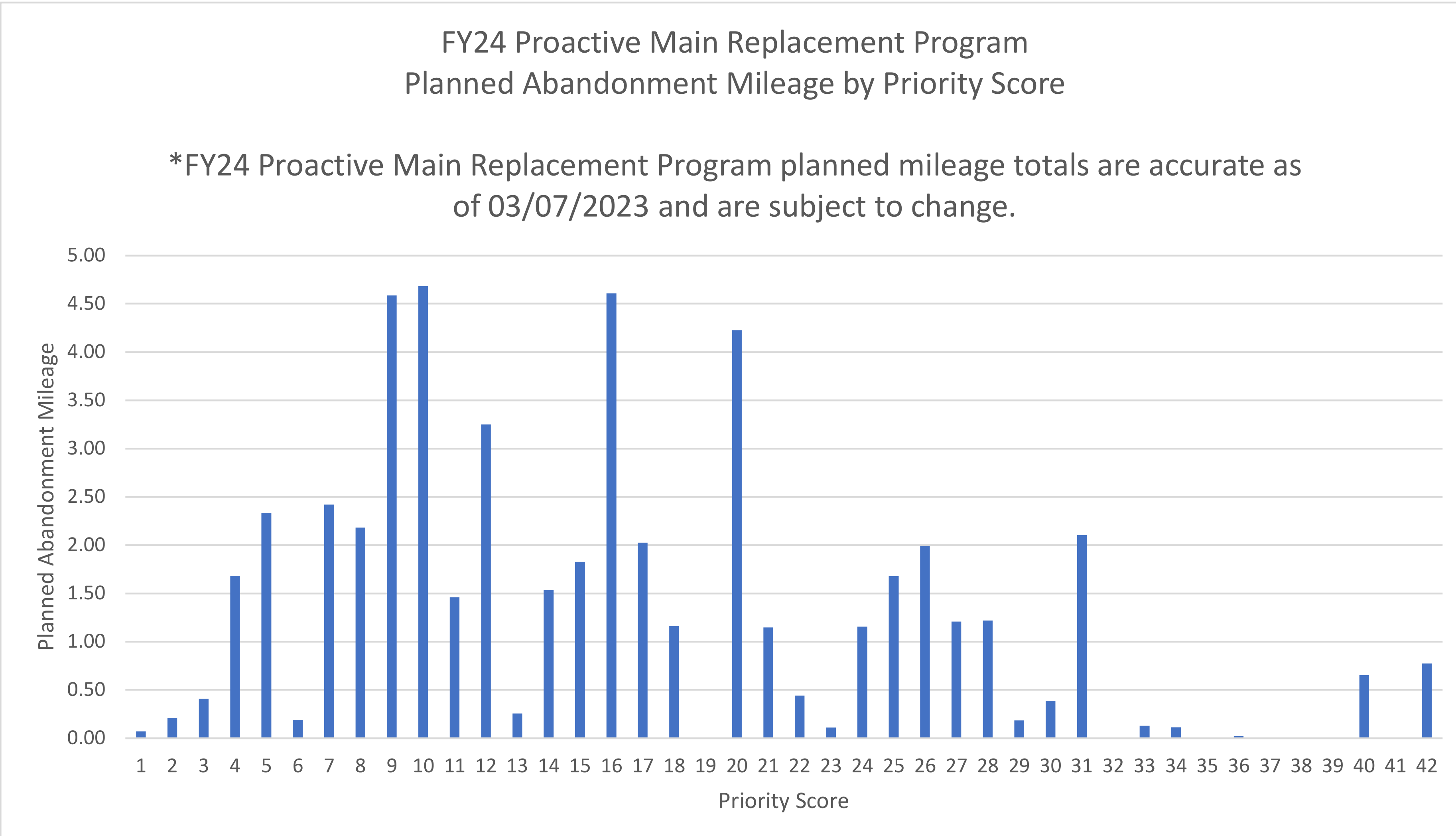
Prepared by or under the supervision of: Corey Hogg

*FY24 Proactive Main Replacement Program planned abandonment mileage totals are accurate as of 03/07/2023 and are subject to change.

FY24 Proactive Main Replacement Program Planned Abandonment Mileage by Priority Score

Priority Score	Planned Abandonment Mileage
1	0.07
2	0.21
3	0.41
4	1.68
5	2.34
6	0.19
7	2.42
8	2.18
9	4.59
10	4.69
11	1.46
12	3.25
13	0.26
14	1.54
15	1.83
16	4.61
17	2.03
18	1.16
19	0.00
20	4.23
21	1.15
22	0.44
23	0.11
24	1.16
25	1.68
26	1.99
27	1.21
28	1.22
29	0.18
30	0.39
31	2.11

32	0.00
33	0.13
34	0.11
35	0.00
36	0.02
37	0.00
38	0.00
39	0.00
40	0.65
41	0.00
42	0.77


FY24 Proactive Main Replacement Program
Planned Abandonment Mileage by Priority Score
*FY24 Proactive Main Replacement Program planned mileage totals are accurate as of 03/07/2023 and are subject to change.
Planned Abandonment Mileage
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42
Priority Score

PUC 4-10
Leak Prone Pipes (LPP)

Request:

Please provide ENG04030 Attachment 1 DIMP factors table for the data that is expected to be used during implementation of the FY24 Plan. Please make the follow indications in rows that will have a decrease in the number of miles indicated in the table:

a. Please highlight in orange any rows forecasted to be impacted by the proposed Proactive Main Program in FY24.

b. Please highlight in yellow any rows forecasted to be impacted by other ISR programs in FY24.

c. Please highlight in blue any rows forecasted to be impacted by non-ISR spending, if forecasted, during FY24.

d. Add a column for the number of miles that will change in each highlighted row, if forecasted.

Response:

a. Please see Attachment PUC 4-10-1. Please note, the Proactive Main Replacement program proposed work plan is accurate as of 03/07/2023 and is subject to change.

b. Please see Attachment PUC 4-10-2. Please note, forecasted work to be done under the ISR is accurate as of 03/07/2023 and is subject to change.

c. The Company does not currently have this information forecasted.

d. The Company does not currently have this information forecasted.

Prepared by or under the supervision of: Corey Hogg

STATE: RHODE ISLAND
REGION: ALL
FACILITY: Services

Mitigation Will Be As Per Appendix D in DIMP, Except As Otherwise Indicated In Notes

Material	Pressure	Meter Set	Mileage	Risk Score	Threat Category	Additional Mitigation Notes	DIMP Factor
Unprotected Bare Steel	> 60 PSI,Not T	Outside	467.1625171	5.44	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
Unprotected Bare Steel	> 60 PSI,Not T	Inside	76.36971929	5.44	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
Unprotected Bare Steel	HP	Inside	1312.59888	5.26	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.90
Unprotected Bare Steel	LP	Inside	29850.79404	4.56	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.51
Unprotected Bare Steel	HP	n/a	4	4.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.32
Unprotected Bare Steel	HP	Outside	3992.351325	4.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.32
Unprotected Bare Steel	LP	n/a	56	3.42	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.89
Unprotected Bare Steel	LP	Outside	2232.723519	3.42	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.89
Unprotected Coated Stee	> 60 PSI,Not T	Inside	20.72452407	3.17	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.75
Unprotected Coated Stee	> 60 PSI,Not T	Outside	207.2452407	3.17	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.75
Unprotected Coated Stee	HP	Inside	2525.795674	3.07	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.69
Wrought Iron	HP	Inside	2.513761468	3.06	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.69
Cast Iron	HP	Inside	2.513761468	3.06	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.69
Wrought Iron	LP	Inside	2.513761468	2.95	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.63
Cast Iron	LP	Inside	64.97106563	2.95	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.63
Unprotected Coated Stee	LP	Inside	2002.088139	2.80	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.55
Wrought Iron	HP	Outside	2.513761468	2.47	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.36
Unprotected Coated Stee	HP	n/a	1E-10	2.45	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.35
Unprotected Coated Stee	HP	Outside	4181.451165	2.45	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.35
Cast Iron	HP	n/a	1E-10	2.37	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.31
Wrought Iron	HP	n/a	1E-10	2.37	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.31
Plastic	> 60 PSI,Not T	Inside	105.007205	2.29	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.26
Plastic	> 60 PSI,Not T	Outside	5612.932296	2.29	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.26
Cast Iron	LP	Outside	15.46930134	2.24	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.24
Wrought Iron	LP	Outside	46.50458716	2.24	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.24
Plastic	HP	Inside	6672.518258	2.22	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.22
Plastic	LP	Inside	24647.05732	2.14	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.18
Unprotected Coated Stee	LP	Outside	174.6952574	2.10	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.16

STATE: RHODE ISLAND
REGION: ALL
FACILITY: MAINS

Mitigation Will Be As Per Appendix D, Except As Otherwise Indicated In Notes

Material	Pressure	Diameter	Mileage	Risk Score	Threat Category	Additional Mitigation Notes	DIMP Factor
Wrought Iron	LP	4" Thru 8"	0.14	2.25 Known Incident	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
Cast Iron	LP	4" Thru 8"	648.42	2.25 Known Incident	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	> 60 PSI,Not T	Over 8"	2.02	4.01	CORROSION / MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	> 60 PSI,Not T	Over 4" Thru 8"	0.81	4.01	CORROSION / MATERIAL/WELD / NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	> 60 PSI,Not T	Upto 4"	1.58	4.01	CORROSION / MATERIAL/WELD / NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	HP	Over 8"	3.95	3.16	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.37
UnprotectedBare Steel	HP	Over 4" Thru 8"	25.22	3.16	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.37
UnprotectedBare Steel	HP	Upto 4"	140.98	3.16	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.37
Cast Iron	HP	4" Thru 8"	4.59	2.95	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.21
Cast Iron	HP	Under 4"	0.02	2.77	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.08
Wrought Iron	HP	Under 4"	0.12	2.77	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.08
UnprotectedCoated Steel	> 60 PSI,Not T	Upto 4"	1.83	2.31	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.73
UnprotectedCoated Steel	> 60 PSI,Not T	Over 4" Thru 8"	1.83	2.31	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.73
UnprotectedCoated Steel	> 60 PSI,Not T	Over 8"	4.21	2.31	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.73
Plastic	> 60 PSI,Not T	Over 4" Thru 8"	31.00	2.27	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
Plastic	> 60 PSI,Not T	Over 8"	0.15	2.27	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
Plastic	> 60 PSI,Not T	Upto 4"	62.43	2.27	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
Ductile Iron	HP	Over 4" Thru 8"	0.67	2.27	NATURAL FORCE / CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
UnprotectedBare Steel	LP	Over 8"	3.40	2.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.66
UnprotectedBare Steel	LP	Over 4" Thru 8"	42.63	2.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.66
UnprotectedBare Steel	LP	Upto 4"	45.79	2.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.66
Wrought Iron	LP	Under 4"	1.02	2.19	NATURAL FORCE	Schedule Replacement When Exposed Or Within Public Works. An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.64
Cast Iron	LP	Under 4"	6.28	2.19	NATURAL FORCE	Schedule Replacement When Exposed Or Within Public Works. An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.64
Cast Iron	HP	Over 8"	16.08	2.12	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.59
Ductile Iron	LP	Upto 4"	6.58	1.76	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1
Ductile Iron	LP	Over 4" Thru 8"	7.61	1.70	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1
Wrought Iron	LP	Over 8"	0.20	1.62	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.21
Cast Iron	LP	Over 8"	92.29	1.62	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.21

STATE: RHODE ISLAND
REGION: ALL
FACILITY: Services

Mitigation Will Be As Per Appendix D in DIMP, Except As Otherwise Indicated In Notes

Material	Pressure	Meter Set	Mileage	Risk Score	Threat Category	Additional Mitigation Notes	DIMP Factor
Unprotected Bare Steel	> 60 PSI,Not T	Outside	467.1625171	5.44	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
Unprotected Bare Steel	> 60 PSI,Not T	Inside	76.36971929	5.44	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
Unprotected Bare Steel	HP	Inside	1312.59888	5.26	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.90
Unprotected Bare Steel	LP	Inside	29850.79404	4.56	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.51
Unprotected Bare Steel	HP	n/a	4	4.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.32
Unprotected Bare Steel	HP	Outside	3992.351325	4.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.32
Unprotected Bare Steel	LP	n/a	56	3.42	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.89
Unprotected Bare Steel	LP	Outside	2232.723519	3.42	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.89
Unprotected Coated Stee	> 60 PSI,Not T	Inside	20.72452407	3.17	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.75
Unprotected Coated Stee	> 60 PSI,Not T	Outside	207.2452407	3.17	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.75
Unprotected Coated Stee	HP	Inside	2525.795674	3.07	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.69
Wrought Iron	HP	Inside	2.513761468	3.06	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.69
Cast Iron	HP	Inside	2.513761468	3.06	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.69
Wrought Iron	LP	Inside	2.513761468	2.95	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.63
Cast Iron	LP	Inside	64.97106563	2.95	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.63
Unprotected Coated Stee	LP	Inside	2002.088139	2.80	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.55
Wrought Iron	HP	Outside	2.513761468	2.47	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.36
Unprotected Coated Stee	HP	n/a	1E-10	2.45	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.35
Unprotected Coated Stee	HP	Outside	4181.451165	2.45	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.35
Cast Iron	HP	n/a	1E-10	2.37	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.31
Wrought Iron	HP	n/a	1E-10	2.37	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.31
Plastic	> 60 PSI,Not T	Inside	105.007205	2.29	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.26
Plastic	> 60 PSI,Not T	Outside	5612.932296	2.29	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.26
Cast Iron	LP	Outside	15.46930134	2.24	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.24
Wrought Iron	LP	Outside	46.50458716	2.24	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.24
Plastic	HP	Inside	6672.518258	2.22	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.22
Plastic	LP	Inside	24647.05732	2.14	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.18
Unprotected Coated Stee	LP	Outside	174.6952574	2.10	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.16

STATE: RHODE ISLAND
REGION: ALL
FACILITY: MAINS

Mitigation Will Be As Per Appendix D, Except As Otherwise Indicated In Notes

Material	Pressure	Diameter	Mileage	Risk Score	Threat Category	Additional Mitigation Notes	DIMP Factor
Wrought Iron	LP	4" Thru 8"	0.14	2.25 Known Incident	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
Cast Iron	LP	4" Thru 8"	648.42	2.25 Known Incident	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	> 60 PSI,Not T	Over 8"	2.02	4.01	CORROSION / MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	> 60 PSI,Not T	Over 4" Thru 8"	0.81	4.01	CORROSION / MATERIAL/WELD / NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	> 60 PSI,Not T	Upto 4"	1.58	4.01	CORROSION / MATERIAL/WELD / NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	3.00
UnprotectedBare Steel	HP	Over 8"	3.95	3.16	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.37
UnprotectedBare Steel	HP	Over 4" Thru 8"	25.22	3.16	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.37
UnprotectedBare Steel	HP	Upto 4"	140.98	3.16	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.37
Cast Iron	HP	4" Thru 8"	4.59	2.95	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.21
Cast Iron	HP	Under 4"	0.02	2.77	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.08
Wrought Iron	HP	Under 4"	0.12	2.77	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	2.08
UnprotectedCoated Steel	> 60 PSI,Not T	Upto 4"	1.83	2.31	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.73
UnprotectedCoated Steel	> 60 PSI,Not T	Over 4" Thru 8"	1.83	2.31	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.73
UnprotectedCoated Steel	> 60 PSI,Not T	Over 8"	4.21	2.31	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.73
Plastic	> 60 PSI,Not T	Over 4" Thru 8"	31.00	2.27	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
Plastic	> 60 PSI,Not T	Over 8"	0.15	2.27	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
Plastic	> 60 PSI,Not T	Upto 4"	62.43	2.27	MATERIAL/WELD	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
Ductile Iron	HP	Over 4" Thru 8"	0.67	2.27	NATURAL FORCE / CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.70
UnprotectedBare Steel	LP	Over 8"	3.40	2.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.66
UnprotectedBare Steel	LP	Over 4" Thru 8"	42.63	2.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.66
UnprotectedBare Steel	LP	Upto 4"	45.79	2.21	CORROSION	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.66
Wrought Iron	LP	Under 4"	1.02	2.19	NATURAL FORCE	Schedule Replacement When Exposed Or Within Public Works. An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.64
Cast Iron	LP	Under 4"	6.28	2.19	NATURAL FORCE	Schedule Replacement When Exposed Or Within Public Works. An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.64
Cast Iron	HP	Over 8"	16.08	2.12	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.59
Ductile Iron	LP	Upto 4"	6.58	1.76	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1
Ductile Iron	LP	Over 4" Thru 8"	7.61	1.70	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1
Wrought Iron	LP	Over 8"	0.20	1.62	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.21
Cast Iron	LP	Over 8"	92.29	1.62	NATURAL FORCE	An additional factor will be applied to the replacement qualification and prioritization algorithm to account for this asset's DIMP risk ranking	1.21

PUC 4-11
Leak Prone Pipes (LPP)

Request:

Please provide the most recent revision of the DIMP in which RIE's data is included.

Response:

Please see Attachment PUC 4-11 which is the 2021 National Grid Distribution Integrity Management Plan that the Company is continuing to follow during the transition.

2021

Gas Distribution Integrity Management Plan

NATIONAL GRID CORPORATION

August 2, 2022

Preface

The development of this Distribution Integrity Management program was initiated in 2009 as a project involving the Northeast Gas Association, the Southern Gas Association, forty seven utilities (including National Grid), and Structural Integrity Associates. These parties collaborated to develop a best-in-class framework. Subsequent to the initial development, National Grid retained Structural Integrity to assist in the customization of the National Grid specific DIM Plan. Departments within National Grid that were directly involved in the Plan development included Operations, Regulatory Compliance, and Distribution Engineering. A team with representatives from these three groups was assigned the task of creating the National Grid DIM Plan by August 2011 for U.S. Gas Operations.

REVISION CONTROL SHEET

Title: National Grid Corporation Distribution Integrity Management Plan

SECTION	PAGES	REVISION	DATE	COMMENTS
1-12	All	0	8/2/2011	INITIAL RELEASE
1-12	All	1	2/17/2012	REVISION 1
1-12 & All Appendices	All	2	8/29/2013	REVISION 2
1-12 & All Appendices	All	3	9/12/2014	REVISION 3
1-12 & All Appendices	All	4	9/1/2015	REVISION 4
1-12 & All Appendices	All	5	9/1/2016	REVISION 5 (Complete Re-evaluation)
1-13 & All Appendices	All	6	8/2/2017	REVISION 6
1-13 & All Appendices	All	7	8/2/2018	REVISION 7
1-13 & All Appendices	All	8	8/2/2019	REVISION 8
1-13 & All Appendices	All	9	8/2/2020	REVISION 9
2, 3, 9, 11, D Appendix	2, 3, 9, 11, 14, 15 &16	9.1	12/14/2020	REVISION 9.1
1-13 & All	All	10	8/2/2021	REVISION 10 (Complete Re-evaluation)
3,4,5,6,7 & A,B,D Appx	3, 4, 5, 6, 7, 14, 15 & 16	10.1	9/30/2021	REVISION 10.1
1-13 & All Appendices	All	11	8/2/2022	REVISION 11

Table of Contents

Table of Figures

Table of Tables

1.0 COMPANY OVERVIEW

National Grid Corporation is one of the largest investor-owned utilities in the world and is the largest distributor of natural gas in the Northeastern US, serving approximately 3.5 million customers in Massachusetts, New York and Rhode Island (See Figure 1-1).

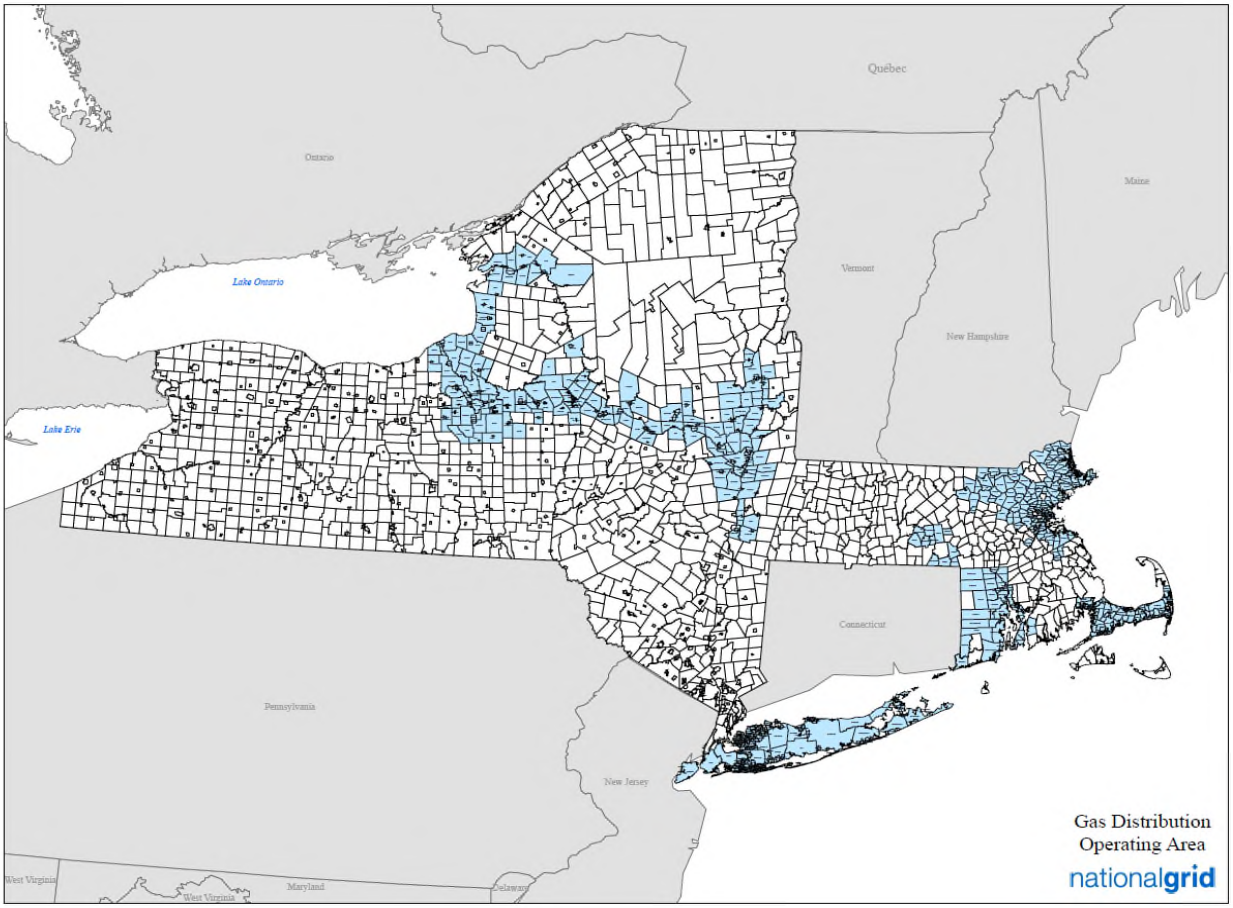


Figure 1-1: National Grid Operating Region

At this time, National Grid provides annual reports to The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) under the following Operator IDs:

Operator ID 1640 – Massachusetts (MA), Boston

Operator ID 13480 – New York, Upstate (UNY)

Operator ID 1800 – New York City (NYC)

Operator ID 11713 – New York, Long Island (LI)

Operator ID 13480 – Rhode Island (RI)

2.0 COMPANY SAFETY

National Grid recognizes that its operations potentially give rise to risk and believes that it can eliminate or minimize those risks to achieve zero injuries safeguarding members of the public. The communities that are served include all those who have a stake in or are affected by the company. By using the best designs, processes, tools, and training, National Grid aims to develop a process-focused approach to mitigating risk, therefore increasing the overall safety of our system and customers. The Distribution Integrity Management Program (DIMP) aims to ensure pipeline integrity by identifying, evaluating, and mitigating the risks within National Grid's system. The following are key elements within the program in order to achieve this goal as per the requirement of 49 CFR §192.1007:

(a) Knowledge
(b) Identify Threats
(c) Evaluate and rank Risk
(d) Identify and implement Measures to address risks
(e) Measure Performance, Monitor Results, and Evaluate Effectiveness
(f) Periodic Evaluation and Improvement
(g) Report results

2.1 COVID-19 Impact on National Grid

In March 2020, National Grid activated the Incident Command Structure (ICS) within all Business Units of the Company's US Operations to respond to the Coronavirus Pandemic (COVID-19). The Role of the ICS was to ensure the safety of all employees and to ensure COVID-19 pandemic measures were in place. Members of the ICS reviewed and approved all operational decisions, with the Incident Commander ultimately responsible for these decisions. The Incident Commander relied upon subject matter experts within the ICS, including the Operations Officer, the Safety and Health Officer, to help set standards and guidance for protective measures to be used to limit the spread of the COVID-19 virus. These Officers, in turn, utilized the expertise of other members of the organization within Operations, Safety, and Health, to assess risks associated with the work being performed and provide guidance on the most effective measures to be used by employees to protect themselves, their coworkers, our customers, and members of the public.

In May 2020, the ICS oversight responsibilities were transitioned to the Plan Forward team and the responsibilities for recommendation of standards and guidance was transferred to the Safety and Health teams in conjunction with input from Operations and Support Services teams.

The Programs within the DIM Plan as well as the Company's jurisdictional portfolio are evaluated on a monthly basis.

3.0 SCOPE

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) amended the Federal Pipeline Safety Regulations on December 4, 2009 to require operators of gas distribution pipelines to develop and implement a Distribution Integrity Management Program (DIMP). National Grid's written integrity management plan also comply with Code of Massachusetts Regulations 220 CMR 99 (Dig Safe Rules), 220 CMR 100.00 through 115.00 (Gas Distribution Code), New York Code, Rules and Regulations 16 NYCRR§ 255 (Transmission and Distribution of Gas), and Rhode Island Division of Public Utilities Rules and Regulations Prescribing Standards for Gas Utilities, Master Meter Systems and Jurisdictional Propane Systems.

The purpose of the DIMP is to enhance safety by identifying and reducing gas distribution pipeline integrity risks. Operators must integrate reasonably available information about their pipelines to inform their risk decisions. The DIMP approach was designed to promote improvement in pipeline safety by identifying and implementing risk control measures beyond those previously established in PHMSA regulatory requirements, when warranted.

This written DIM Plan addresses the DIM Rule which requires operators to develop and implement a DIM Program that addresses the following elements as per §192.1007:

(a) Knowledge
(b) Identify threats
(c) Evaluate and rank risk
(d) Identify and implement measure to address risks
(e) Measure performance, monitor results, and evaluate effectiveness
(f) Periodic evaluation and improvement
(g) Report results

Because of the significant diversity among distribution pipeline operators and pipelines, the requirements in the DIM Rule are high-level and performance-based. The DIM Rule specifies the required program elements but does not prescribe specific methods of implementation.

This written Integrity Management Plan applies to gas distribution pipelines operated by National Grid Corporation. Gas distribution pipelines include the mains, services, service regulators, customer meters, valves, and other gas carrying appurtenance attached to the pipe. This Integrity Management Plan also applies to transmission pipelines that are not covered by the National Grid Transmission Integrity Management Program (IMP). Table 3-1 below summarizes which National Grid piping systems (mains) are covered by the Transmission Integrity Management Program and which are covered by the DIM Program.

Table 3-1: Program Coverage

Pipeline System	Approximate Miles of Mains as of 2021 PHMSA Report[1]	Asset Family	Integrity Program	Pipeline Attributes	National Grid Management Plans
Covered+ DOT Transmission	296 miles	Transmission	TIMP	= or >20% SMYS and in HCA	Assessment, Preventive & Mitigative Measures
Non-Covered DOT Transmission[2] in Piggable MCA[3]	95 miles	Transmission	TIMP	= or >20% SMYS and in piggable MCA	Preventive, Mitigative & *Performance Measures*
Other DOT Transmission[4] (Not in HCA or Piggable MCA)	96 miles	Transmission	DIMP	= or >20% SMYS and not in a HCA or piggable MCA	Preventive, Mitigative & *Performance Measures*
Local Transmission (Distribution per §192.3)	674 miles	Transmission	DIMP	<20% SMYS >124 psi NYS > 200 psi NE	Preventive, Mitigative & *Performance Measures*
Distribution[5]	About 35,877 miles	Distribution	DIMP	< or = 124 psi NYS < or = 200 psi NE	Preventive, Mitigative & *Performance Measures*

+ Covered under Subpart O

1- Provided for illustrative purposes, see Annual PHMSA Report for current mileage.

2- As of 2020, Non-Covered DOT Transmission is not managed as Local Transmission under DIMP.

3- Included in TIMP Program. Moderate Consequence Area (MCA) – a new definition for all non-HCA DOT mileages effective 7/1/2020. Piggable MCA assessment per 192.710, Transmission lines: Assessments outside of high consequence areas.

4- Managed as Local Transmission under DIMP.

5- Distribution Inventory includes Local Transmission and Other DOT Transmission (Not in HCA or Piggable MCA)

This Plan also acknowledges National Grid's responsibilities relative to Oxbow Farm's master meter system in Middletown, RI in accordance with its Agreement with RI on Oxbow Farms Apartments (Docket# D-06-54). National Grid recognizes its ownership, operation and maintenance of the natural gas pipelines downstream of the Oxbow Farms master meter system. This includes performing walking leak surveys on a 3-year cycle, the cathodic protection of steel facilities and damage prevention, public awareness, key valves, atmospheric corrosion.

All piping was included in its respective asset category for threat identification, risk ranking, risk mitigation, and all other requirements as identified in 49CFR, Part 192.1015.

This plan does not cover:

Customer owned lines – piping downstream of the service line (as defined in Section 5.0).

Gathering lines –National Grid does not currently own or operate gas gathering lines.

Regulator stations - covered under the National Grid's Station Integrity Management Program (SIMP)

Transmission lines - covered under the National Grid's Transmission Integrity Management Program *(TIMP)*, refer to Table 3-1.

Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG) - covered under the Asset Management Program (AMP)

3.1 DIM Plan Review

On February 11th, 2019, Gas Distribution Engineering awarded the contract to safety management consultant, Exponent, to assist in adopting API RP 1173 core elements (DIMP focused) into the DIMP Plan, to identify gaps within the DIMP Plan, and to ensure program compliance with PHMSA Inspection Form-22 and 24. Exponent was also tasked to review the Massachusetts -Senators' letter, and AGA's recommendations as the result of 2018 Columbia gas Incident, against the information contained within National Grid's DIM Plan.

4.0 PURPOSE AND OBJECTIVES

The purpose of the DIM Program is to enhance safety by identifying and reducing gas distribution pipeline integrity risks. Managing the integrity and reliability of the gas distribution pipeline has always been a primary goal for National Grid; with design, construction, operations and maintenance activities performed in compliance with or exceeding the requirements of the Code of Federal Regulations (CFR) and as well as the following where applicable: Code of Massachusetts Regulations 220 CMR 99, and 100.00 through 115.00, New York Code, Rules and Regulations 16 NYCRR§ 255 (Transmission and Distribution of Gas), and Rhode Island Division of Public Utilities Rules and Regulations Prescribing Standards for Gas Utilities, Master Meter Systems and Jurisdictional Propane Systems.

The objective of this DIM Plan is to establish the requirements to comply with 49 CFR § 192.1005, 192.1007, 192.1009, 192.1011, 192.1013 and (192.1015 for the master meter system in Middletown, RI) pertaining to integrity management for gas distribution pipelines. National Grid does not currently propose to reduce the frequency of periodic inspections and tests allowed by 192.1013 but may submit such proposals for consideration and concurrence by regulators in the future.

The DIM Plan is comprised of seven elements as depicted in Figure 4-1 (DIM Plan Section reference also provided).

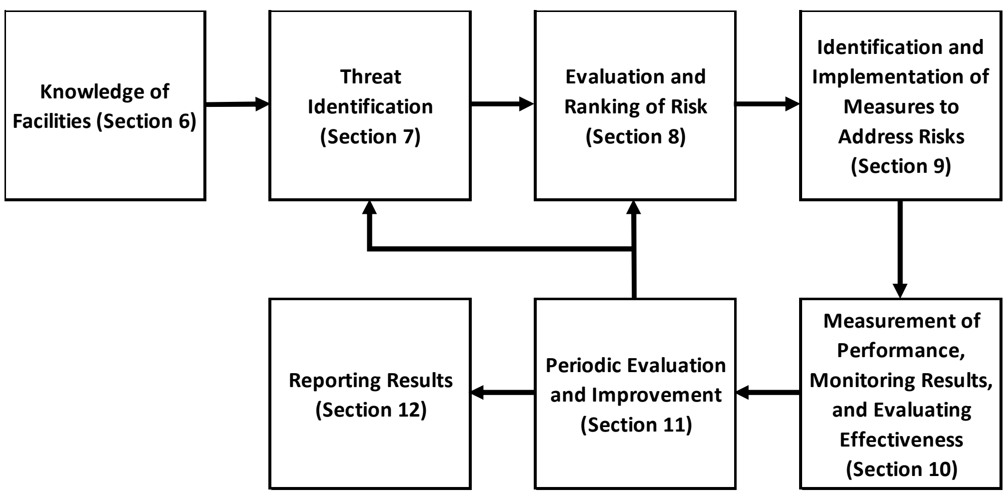


Figure 4-1: DIM Plan Elements

In addition to the key elements shown in Figure 4-1, the DIM Plan also establishes requirements for reporting of mechanical fitting failures (Section 12.1) and maintaining records (Section 0).

All elements of this DIM Plan were implemented on August 2, 2011.

4.1 Roles and Responsibilities

The purpose of this section is to describe key roles within the organization.

4.1.1 Vice President, Gas Asset Management

The Vice President of Gas Asset Management is responsible for oversight of the DIM Plan and assures that the program processes are implemented by the organization in accordance with this DIM Plan and associated regulatory requirements. The Vice President of Gas Asset Management may delegate some or all of these responsibilities to the Director of Gas Distribution Engineering.

4.1.2 Director, Gas Distribution Engineering

The Director of Gas Distribution Engineering has overall responsibility to assure that the DIM Plan processes are implemented by the organization in accordance with this DIM Plan and associated regulatory requirements. The Director conducts a month-to-month review of the program with the Manager to make sure the DIM Plan aligns with the Company's operating procedures. The Director of Gas Distribution Engineering of DIMP may delegate some or all of these responsibilities.

4.1.3 Manager, DIMP

The Manager of DIMP has the responsibility for day-to-day program oversight, policy integrity, facility replacement priorities, and responsibility to assure that the plan is implemented effectively and is integrated with the Company's operating procedures. This Plan assigns authority to the Manager for approval of the DIM Plan.

4.1.4 Engineer, Gas Distribution Engineering

The Integrity Engineer is responsible for gathering all pertinent data for DIMP Appendixes including Risk Ranking. Ensure that all the changes made to the plan during its yearly and 5-year comprehensive Plan revisions are documented and tracked.

4.1.5 Subject Matter Experts (SMEs)

The subject Matter Experts act as the knowledgeable authority regarding a specific Company system or area of expertise. The assignment of SME responsibility is delegated to the appropriate individual(s) within the National Grid organization or to qualified contractors. The SME is responsible for input into specific DIMP related processes or oversight of DIMP related tasks. An SME may be assigned for a specific issue and/or geographic area of the company or may represent the company system- wide in certain technical areas as appointed by the DIMP Director or Manager.

4.2 DIM Program Administration

Gas Asset Management is responsible for the overall Integrity Management Program. Table 4-1 Provides a RACI Chart outlining the Departments that are either responsible, accountable, consulted or informed on the seven elements of the DIMP.

Table 4-1: Roles and Responsibilities (RACI Chart)

Stakeholder Group	Facilities Knowledge	Threat Identification	Risk Evaluation & Prioritization	Threat Mitigation & Implementation	Performance & Monitoring	Performance Evaluation & Improvement	Reporting Results
Gas Asset Management	A	A	A	A	A	A	A
Gas Field Ops	R	R	C	R	R	R	I
Gas Construction	I	I	I	R	I	I	I
Corrosion Control	R	R	I	R	R	R	R
Project Management	I	I	I	R	I	I	I
Resource Planning	I	I	I	R	I	I	I
Project Engineering & Design	I	I	I	R	I	I	I
Damage Prevention	I	I	I	R	I	I	I
Pipeline Safety & Compliance	I	C	C	I	I	C	I

Notes:

R = responsible for performing the task
A = accountable for overall result of task
C = consulted to provide input or participate in the task
I = informed about the progress or results of task

Table 4-2: DIM Program Administration

Plan Section	Role / Responsibility	Responsible Position *
4.1	Overall Program Oversight	Vice President, Gas Asset Management
4.1	Overall Program Implementation	Director, Gas Distribution Engineering
6.1, 6.2, 6.3 Appendix A	Updates to Appendix A	Manager, DIMP or designee
6.4	Update Action Plans for Gaining Additional Knowledge	Manager, DIMP or designee
6.6, Appendix A Appendix B	Conduct and Record SME Interviews as necessary for input into Appendix A (Knowledge) and Appendix B (Threat Identification)	Manager, DIMP or designee
7.0, 7.1, Appendix B	Update Threat Identification (Appendix B) as new or modified threats are known or recognized	Manager, DIMP or designee
8.1	Update the Risk Assessment and Ranking process and/or algorithms	Manager, DIMP or designee
Appendix C	Perform and document updates to the Risk Assessment & Ranking Results.	Manager, DIMP or designee
9.1, 9.2, Appendix D	Ongoing updates to Mitigation Measures to Address Risks	Manager, DIMP or designee
10.1 thru 10.6, Appendix E	Maintain Performance Measures (updates to actual performance as well as the associated baselines)	Manager, DIMP or designee
11.1, Appendix F	Periodic Updates to the Plan	Manager, DIMP or designee
11.2, Appendix F	Conduct and document the Annual Effectiveness Review	Manager, DIMP or designee
11.1, Appendix F	Conduct the Program Re-evaluation	Manager, DIMP or designee
12.1	Prepare and submit the annual report to PHMSA and the State Pipeline Safety Authority	Manager, DIMP or designee
13.0	Maintain DIM Program Records and Files as required by Retention Policy	Manager, DIMP or designee

4.2.1 Organizational Chart

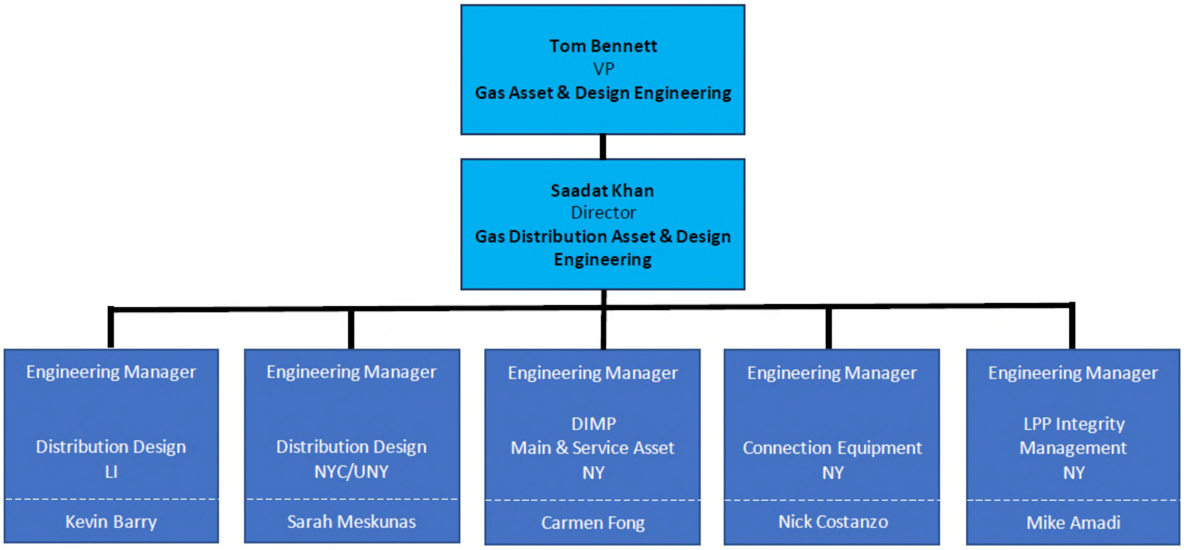


Figure 4-2: New York Organization Chart

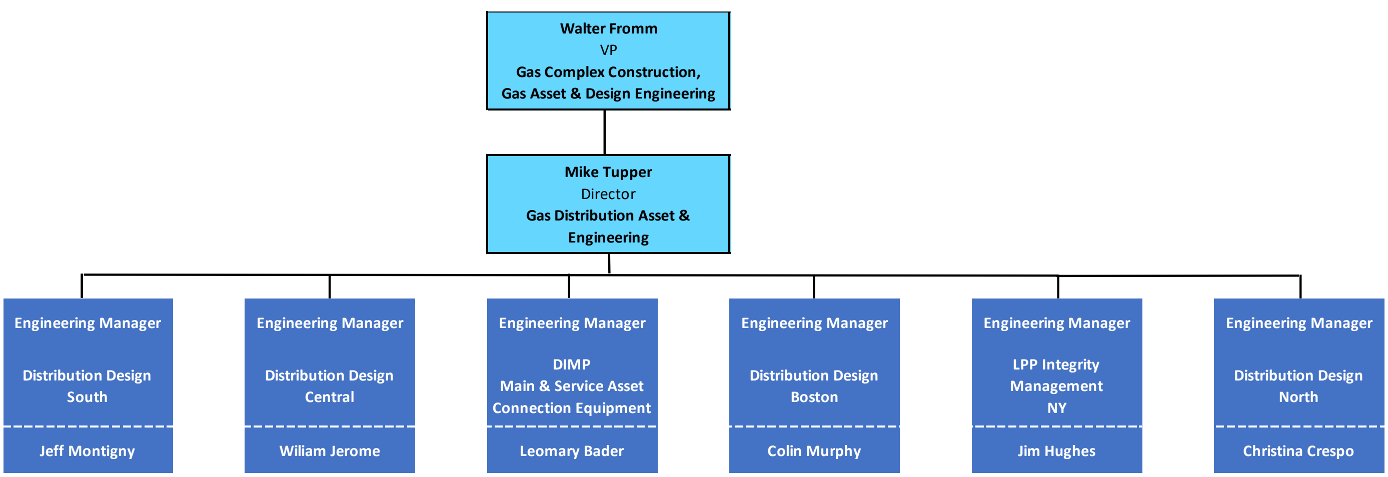


Figure 4-2.1: New England Organization Chart

4.3 How to Use this Plan

This DIM Plan is intended to be a resource and decision-making guide for implementing the DIM Program at National Grid. The 12-section general Plan applies to all National Grid jurisdictions. There is also a state-specific Appendix for each of the three states in which National Grid operates. The general IMP and DIM Program workflow is outlined in Figure 4-3.

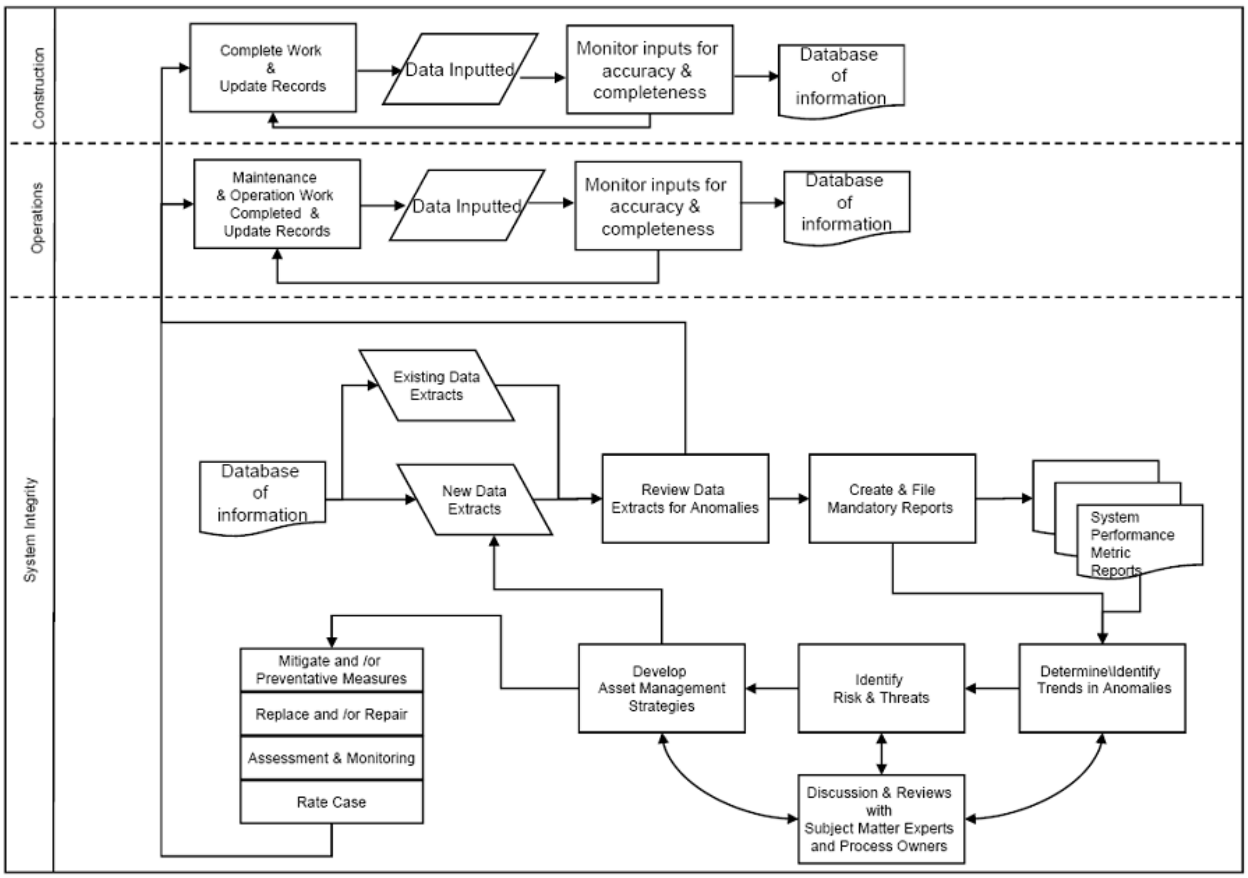


Figure 4-3: DIM Program Process Flow

5.0 DEFINITIONS AND ACRONYMS

The definitions provided in 49 CFR, §192.3 and §192.1001 shall apply to this DIM Plan. The following definitions and acronyms shall apply to this DIM Plan.

American Petroleum Institute Recommended Practice 1173 (API RP 1173): API RP 1173 is Safety Management System that was developed by the American Petroleum Institute. **Baseline**: A value established for the purposes of evaluating the ongoing results of a performance measure. Baselines are established as a matter of judgment and can change and evolve over time.

Business Management System (BMS): The Company has adopted the BMS standards that brings together best practice from across all regions.

COF: Consequence of Failure.

D.I.R.T.: Damage Information Reporting Tool – A secure, national web application for the collection, analysis and reporting of underground facility damage information for all stakeholders. More information on D.I.R.T. may be found at the Common Ground Alliance's (CGA's) website at www.cga-dirt.com.

Distribution Integrity Management Plan (DIM Plan): A written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with subpart P of 49 CFR Part 192 (reference §192.1001).

Distribution Integrity Management Program (DIM Program): An overall approach used by an operator to ensure the integrity of its gas distribution system (reference §192.1001).

Distribution Integrity Management Program Files: Operator records, databases, and/or files that contain either material incorporated by reference in the Appendices of the DIM Plan or outdated material that was once contained in the DIM Plan Appendices but is being retained in order to comply with record keeping requirements.

DIM Rule: 49 CFR, Part 192, Subpart P.

Distribution Line: A pipeline other than a gathering or transmission line (reference §192.3).

EFV: Excess Flow Valve. An Excess Flow Valve is a safety device that is designed to shut off flow of natural gas automatically if the service line breaks.

Excavation damage: A physical impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction of the facility including, but not limited to, the protective coating, lateral support, cathodic protection, or the housing for the line device or facility (reference §192.1001).

Hazardous Leak: A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous (reference §192.1001).

HDPE: High Density Polyethylene.

FOF: Frequency of Failure; synonymous with Likelihood of Failure.

Transmission Integrity Management Program (TIMP): A program used to manage gas transmission pipeline integrity in compliance with Subpart O of 49CFR, Part 192.

Main: A distribution line that serves as a common source of supply for more than one service line (reference §192.3).

MDPE: Medium Density Polyethylene.

Master Meter System: A pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents

Mechanical fitting – As defined in the instructions for completing Form PHMSA F7100.1-1; includes Stab Type Mechanical Fittings, Nut Follower Type Mechanical Fittings, Bolted Type Mechanical Fittings and other types as may be specified by PHMSA.

NTSB: The National Transportation Safety Board.

PHMSA: The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration.

Pipeline: All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies (reference §192.3).

Region: **A**reas within a distribution system consisting of mains, services, and other appurtenances with similar characteristics and reasonably consistent risk. The term Region may also apply to a geographic area within the operator's system.

Risk: A relative measure of the likelihood of a failure associated with a threat and the potential consequences of such a failure.

Risk Model: The integration of facility data, operational data, SME input, and established algorithms to estimate the relative risk associated with a gas distribution system threat.

Service Line: A distribution line that transports gas, or is designed to transport gas, from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is furthest downstream, or at the connection to customer piping if there is no meter. In New York State, under 16 NYCRR § 255.3, a service line ends at the first accessible fitting inside a wall of the customer's building where a meter is located within the building, or at the building wall if the meter is located outside the building.

Service Line Shut-off Valve: a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed (reference §192.385).

SME: Subject Matter Expert. An SME is an individual who is judged by the operator to have specialized knowledge based on their expertise or training.

Sub-Threat: A threat type within one of the primary threat categories specified in §192.1007(b).

Ticket: A notification from the one-call notification center to the operator providing information of pending excavation activity for which the operator is to locate and mark its facilities.

.

6.0 KNOWLEDGE OF FACILITIES

The objective of this section is to assemble and demonstrate as complete of an understanding of the company's infrastructure as possible using reasonably available information from past and ongoing design, operations and maintenance activities. In addition, this plan identifies what additional information is being sought for the program and provides a plan for gaining that information over time through normal activities.

National Grid has a long history of systematically managing its distribution systems. The Company actively participates in committees of the American Gas Association (AGA), the Northeast Gas Association (NGA), the American Society of Mechanical Engineers (ASME), and the National Association of Corrosion Engineers (NACE).

The National Grid Distribution Engineering Department is responsible for the development and implementation of Integrity Management Programs for Gas Distribution facilities and pipelines. The department compiles and analyzes system and operating data, files annual reports to the Department of Transportation (DOT) and State regulators, generates periodic bulletins, and prepares various Integrity Reports and Analyses. Data analysis is an important component of Integrity Management. System performance, analysis, risk, threats, asset management, replacement strategies and rate case support are all performed. These engineering and operational activities require knowledge of the system inventory, age, and annual performance, as well as performance trends over time.

6.1 Policy & Procedures

National Grid has a number of policies and procedures that are related to integrity management and asset management of its gas distribution system. Table 6-1 below has been prepared to summarize which procedures exist to cover the elements as outlined in §192.1007.

For example: National Grid follows the nine (9) elements contained within the published PHMSA Damage Prevention Assistance Program (DPAP). The Company has been actively involved in mark outs and damage prevention for over 35 years and these processes are covered under numerous legacy operating procedures and test instructions. Mark out and damage prevention statistics are tracked by region.

Section 11.0, Periodic Evaluation and Improvement, will identify any areas, policy or procedures that will require changes to comply with the rule or to improve the process over time.

Table 6-1: Policy Documents Related to Integrity Management for Distribution[2]

Category	Covered Elements per 192.1007	Element Description	Procedure	Procedure Title	Regions
Annual System Integrity Gas Distribution Report	(a) (1), (2), (4), (b), (c), & (f)	Demonstrating Knowledge, Identified Threats & Periodic Evaluation	N/A	Gas Distribution Facilities 10 Year Trend Analysis	All Regions
Improving Knowledge, Asset Information	(a) (1), (a) (3) & (a) (5)	Identify Additional information	CNST01005	Preparation of Gas Facility Historical Records	All Regions
Asset Information	(a) (1) & (5)	Demonstrating Knowledge	GEN03002	Preparation and Processing Gas Main and New Services Work Packages	All Regions
Asset Information	(a) (1) & (a) (5)	Demonstrating Knowledge	CNST06020	Completion and Processing of Gas Service Record Cards	All Regions
Risk Scoring Policy	(c)	Ranking Risk	GEN01002	Risk Scoring Policy	All Regions
Annual DOT Reports	(b) & (g)	Identify Threats & Reporting Results	GEN01020	Preparation and filing of DOT Annual Report for the Gas Transmission and Distribution System	All Regions
Problematic Materials	(a) & (b)	Demonstrating Knowledge & Identifying Threats	GEN01009	Reporting Nonconforming Material	All Regions
Damage Prevention Policy	(d)	Mitigate Risk	DAM01000	Damage Prevention Policy	All Regions

Category	Covered Elements per 192.1007	Element Description	Procedure	Procedure Title	Regions
System Operation Procedures	(d)	Mitigate Risk	GCON02001	System Operating Procedure (SOP)	All Regions
Welding Policy	(d)	Mitigate Risk	CNCSTO5002	Welding Policy	All Regions
Operator Qualification Plan	(d)	Mitigate Risk	GEN01100	Operator Qualification Plan	All Regions
Asset Information	(a) (1), (a) (2), (a) (3), (a) (5) & (d)	Demonstrating Knowledge, Mitigate Risk	ENG01002	Design of Gas Regulator Stations	All Regions
Corrosion Design Criteria	(d)	Mitigate Risk	COR01100	Corrosion Design Criteria	All Regions
Leakage Survey	(d)	Mitigate Risk	CNST02001	Leakage Survey Policy	All Regions
Leakage Survey	(d)	Mitigate Risk	CNST02002	Leakage Surveys	NYC, LI
Leakage Survey	(d)	Mitigate Risk	CNST02003	Building of Public Assembly Inspections	NYC, LI
Leakage Survey	(d)	Mitigate Risk	LSUR-5030	Building of Public Assembly	MA
Leakage Survey	(d)	Mitigate Risk	CNST02022	Special Survey (Schools & Hospitals) for Rhode Island	RI
Leakage Survey	(d)	Mitigate Risk	CNST02001-RI	Leakage Survey Policy	RI
Leakage Survey	(d)	Mitigate Risk	LSUR-5020	Walking Survey	MA
Special Winter Operations	(d)	Mitigate Risk	CNST02004	Winter Leak Operations	All Regions

Category	Covered Elements per 192.1007	Element Description	Procedure	Procedure Title	Regions
Corrosion Control	(d)	Mitigate Risk	COR02100	Requirements for Corrosion Inspection, Testing and Repair	All Regions
Atmospheric Corrosion Inspections	(d)	Mitigate Risk	COR02010	Atmospheric Corrosion Inspection of Services	NYC, LI RI, UNY
Corrosion Control	(d)	Mitigate Risk	COR03002	Measuring Pipe-To-Soil Potential	All Regions
Valve Inspection Policy	(d)	Mitigate Risk	CNST04009	Valve Inspection Policy	All Regions
Classifying Gas Leaks	(d)	Evaluating Risk	CNST02009	Classifying Gas Leaks	NYC, LI, UNY
Classifying Gas Leaks	(d)	Evaluating Risk	CNST02009-MA	Classifying Gas Leaks	MA
Eliminating Gas Leaks	(d)	Mitigate Risk	CNST02010	Leak Response and Repair	NYC, LI, UNY
Eliminating Gas Leaks	(d)	Mitigate Risk	CNST02010-MA	Leak Response and Repair	MA
Surveillance of Gas Leaks	(d)	Mitigate Risk	CNST02011	Surveillance of Classified Leaks	NYC, LI, UNY
Surveillance of Gas Leaks	(d)	Mitigate Risk	CNST02011-MA	Surveillance of Classified Leaks	MA
First Responder	(d)	Evaluating Risk	CNST02013 -MA	First Responder – Massachusetts	MA
First Responder	(d)	Evaluating Risk	CNST02013 -NY	First Responder – New York	NYC, LI, UNY

Category	Covered Elements per 192.1007	Element Description	Procedure	Procedure Title	Regions
First Responder	(d)	Evaluating Risk	CNST02013 -RI	First Responder – Rhode Island	RI
Odor Monitoring	(d)	Mitigate Risk	INR06001	Odor Monitoring	All Regions
Regulator Station Inspection	(d)	Mitigate Risk	INR03001	Regulator Station Monthly Inspection Policy	All Regions
Regulator Station Inspection	(d)	Mitigate Risk	INR03003	Regulator Station Annual Inspection Policy: New England	MA, RI
Asset Management Strategy	(d)	Mitigate Risk	ENG04030	Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement	All Regions
Survey & Inspection	(d)	Mitigate Risk	CMS06006	Inspecting Service Regulators and Regulator Vent Piping	MA
Survey & Inspection	(d)	Mitigate Risk	CNST02005	Patrolling Transmission Pipelines	All Regions
Asset Management Strategy	(d)	Mitigate Risk	CNST06001	National Grid's Policy for Inactive Services	All Regions
Asset Management Strategy	(d)	Mitigate Risk	CNST06005	Inspection and Abandonment of Inactive Services	All Regions
Asset Management Strategy	(d)	Mitigate Risk	CNST06009-MA	Meter/Service Relocation Guideline	MA
Regulators	(d)	Mitigate Risk	ENG02001	Design of Gas Services	All Regions

Category	Covered Elements per 192.1007	Element Description	Procedure	Procedure Title	Regions
Purging Operations	(d)	Mitigate Risk	CNST03006	Purging Operations - Direct Displacement	All Regions
Purging Operations	(d)	Mitigate Risk	CNST03007	Purging Operations - Complete Inert Gas Fill	All Regions
Purging Operations	(d)	Mitigate Risk	CNST03008	Purging Operations - Slug Method	All Regions
Cast Iron Management	(d)	Mitigate Risk	DAM01007/ DAM01009	Cast Iron Encroachment Policy for New York State	LI, UNY, NYC
Cast Iron Management	(d)	Mitigate Risk	DAM01008	Cast Iron Encroachment Policy for Massachusetts and Rhode Island	MA, RI

[2] Note: Table 6-1 may not include all the policies and procedures related to the DIM Plan. Refer to the Codes and Standards website *http://dc-gasweb1/codesnstds/SP3IndexB.asp* for the Company's policies and procedures.

These documents are subject to revision or replacement at any time. It is not practical to issue DIM Plan revisions for every policy/procedure change or update. Table 6-1 is updated when a full Plan revision occurs. Refer to the Company's Gas Work Method site for the most current Gas Standards, and Policies.

6.2 Overview of Past Design, Operating, Maintenance, and Environmental Factors

National Grid owns and operates approximately 35,877 miles of cast iron, steel (non-IMP Transmission) and plastic distribution mains at various pressures from low to high throughout its service territory, as well as the associated services, connection equipment, instrumentation and regulation, and other appurtenances. The Company has sought and obtained regulatory approval to upgrade, replace and maintain the distribution systems needed to reduce risk and to address threats to its system and the customers it serves. Since annual system performance statistics can easily vary due to external conditions (e.g., weather), programs and plans must be based on the performance of the system over time. Identifying trends and evaluating data requires an understanding of the science of past designs, operating and maintenance histories. National Grid's knowledge of its gas distribution system is supported by the Company's gas industry experience and data.

National Grid separates its gas distribution system into two primary asset classes; Mains & Services which includes associated connection equipment, and Instrumentation & Regulation. National Grid also divides assets into sub-classes (regions) which include distinctions by factors such as material, size, vintage, pressure, construction method, and location.

6.2.1 Bare and Coated Steel Mains & Services

The modes and mechanisms of failure associated with bare-steel corrosion are well understood by corrosion experts and documented in a number of texts on the topic. It is a known fact that non-cathodically protected bare steel pipe, buried in the earth where there is moisture in the soil and without cathodic protection, will corrode over time. This corrosion may occur over the entire surface of the pipe and it may take many years before the first corrosion leak occurs. However, once the first leak on a pipeline segment occurs, there are other points on the pipe where the pipe is losing metal and where corrosion pits are becoming deeper. As corrosion pitting continues and the pipes continue to lose metal, these pipes will increasingly experience additional leaks. Eventually many additional points of corrosion may result in an unmanageable leak rate.

The deterioration mentioned above is a function of time in the ground and is also influenced by the particular environment. This information is evidenced by the fact that the USDOT has not allowed the installation of unprotected or bare steel for gas service since 1971. Furthermore, an early scientific reference regarding the failure rate of buried steel pipe was given in the book "Soil Corrosion and Pipe Line Protection" by Scott Ewing Ph.D., published in 1938. In the text, the performance of the service pipes in the Philadelphia Gas Works System was plotted and showed that corrosion leak occurrences over time on bare steel pipe increased at an exponential rate. This graph is shown below in Figure 6-1. When this text was written the natural gas industry was still in its infancy and high performance materials such as plastic and well-coated and cathodically protected steel were not available or well understood.

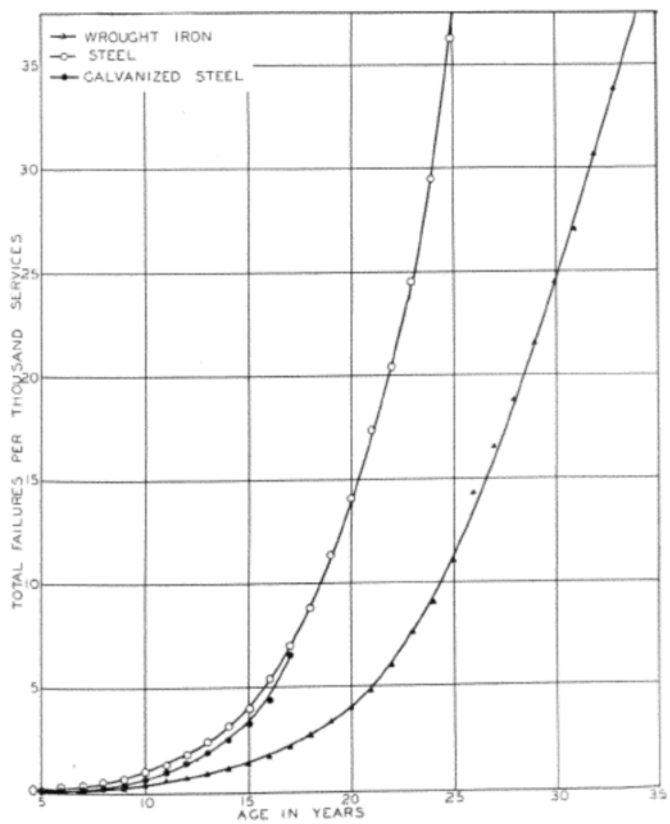


Fig. 7. Failure curves of house services in the Philadelphia Gas Works System.

Figure 6-1: Chart Indicating Exponential Leak Rates for Bare Steel Gas Service (1938)

This very same finding is corroborated today in more modern texts. One such text that is considered by many to be a foundational book for the study of corrosion is: "Peabody's Control of Pipeline Corrosion" by A.W. Peabody, published by the National Association of Corrosion Engineers International, the Corrosion Society (Second Edition 2001). This text, published more than 70 years after the Ewing text, reaffirms the fact that leak incidents on unprotected bare pipe will occur at an exponentially increasing rate. In the Peabody text, this is shown on semi log paper. A copy of the graph used to describe this in the Peabody text (Figure 15.1 in Peabody) is shown in Figure 6-2 below.

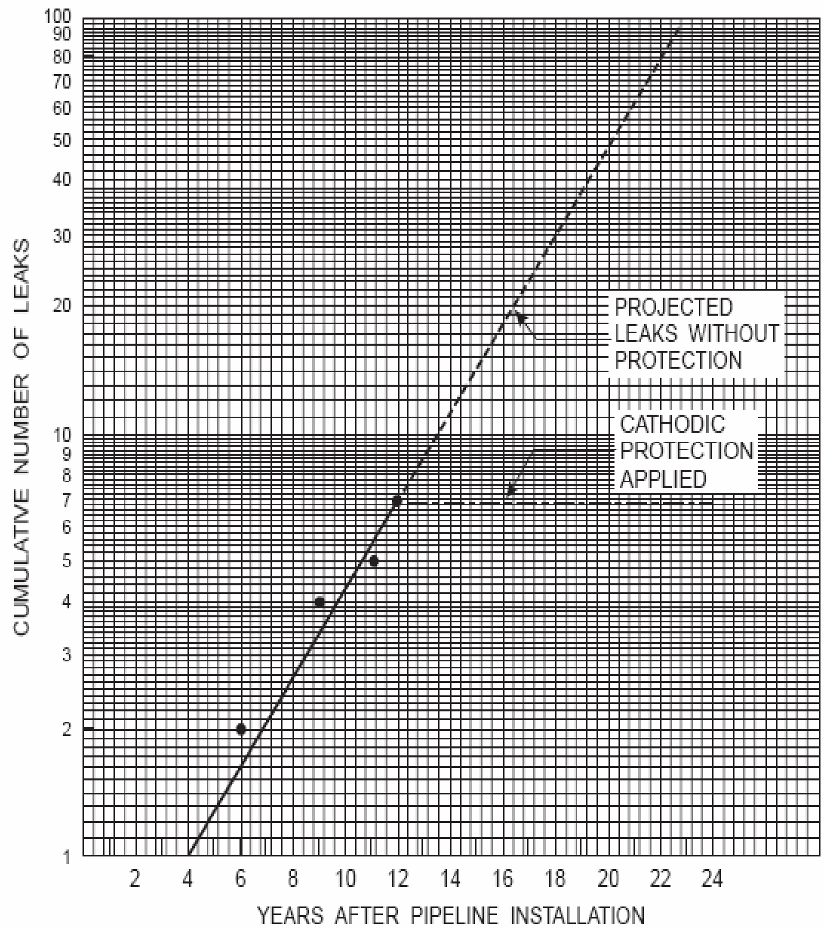


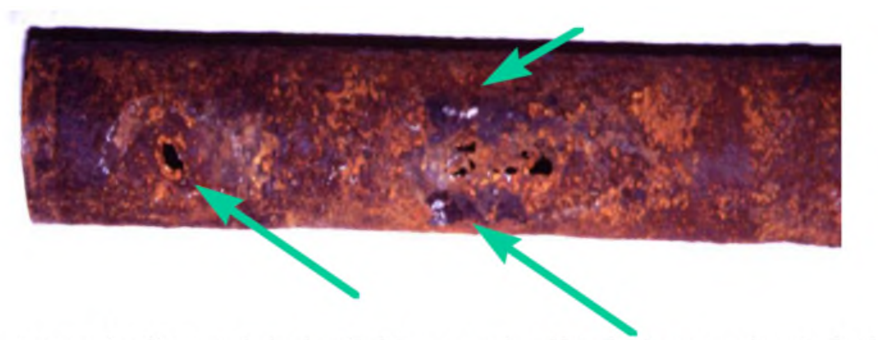
Figure 15.1 Cumulative number of leaks without CP.

Figure 6-2: Chart Indicating Exponential Leak Rates for Bare Steel Gas Service (2001)

As shown on this graph, no leakage occurs during the initial life of the pipe (first leak occurred 4 years after placing the piping in service). Then, in the next 4 years, 1.5 new leaks occurred. Then, in the next 4 years, 4.5 new leaks occurred. Then, in the next 4 years, 11 new leaks occurred. This increasing frequency of leaks continues at a rate that places the cumulative leak count off the scale, past the 23rd year, with more than 100 cumulative leaks occurring. What is important to note is not that the leaks are occurring, but that they are occurring at an ever-increasing frequency as a function of time (once the corrosion process has reached the point of producing the initial leak). Although National Grid's inventory of main and services contains many pipes that have exceeded the 23 years noted, not all of these pipes have experienced leaks at the same initial time.

This exponential growth of leak occurrences on bare-steel pipe is scientifically documented as indicated in the text above. This exponential growth of leak occurrences on bare steel pipe is also well known by experienced gas system operators who perform bare-steel repairs and find themselves installing multiple leak repair sleeves on sections of corroding pipe.

This ever-increasing frequency of leak incidents is evidence of the corrosion mechanisms. Bare steel pipe is undergoing continuous deterioration by corrosion. In some locations, the deterioration is more aggressive than in other locations. In many cases, although the wall thickness is penetrated at only a single point, it can be seen that the entire pipe may have been degraded to the point where future leaks will occur at an ever-increasing rate. This is visually obvious by viewing the piece of corroded pipe shown from the USDOT website in Figure 6-3. In this picture, there may be only a few points of actual leakage, but the pipe shows apparent signs of distress along the entire wall thickness.



An example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground. Operators should use either polyethylene pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

Figure 6-3: Bare Steel Pipe Corrosion

Wrought iron pipes, while less brittle than cast-iron mains and service lines, are also subject to corrosion. The corrosion of wrought iron is similar to bare steel in its exponential leak rate growth.

Coated steel mains and services, when cathodically protected against corrosion, are an excellent and well-performing gas distribution material. They resist corrosion and have significantly higher strength than plastic. All underground steel pipe installed after July 31, 1971 is required by federal code (per 49 CFR 192, Subpart I) to be coated and cathodically protected and is regularly tested to ensure an adequate level of protection and compliance. In many cases, steel pipe installed before 1971 is also coated, cathodically protected, and regularly tested. However, coated steel mains and services that are unprotected can undergo accelerated corrosion if the coating is breached – either by damage or disbonding. Such mains are currently viewed by National Grid as not protectable and are considered to be ineffectively coated and subject to the same risks as bare unprotected steel.

6.2.2 Cast Iron and Wrought Iron Pipe

6.2.2.1 Cast Iron Pipe

The natural gas industry considers cast-iron mains, non-cathodically protected steel mains, and services to be higher risk materials. Cast Iron mains are among the oldest materials remaining in gas distribution systems, often pre-dating the 1900's. Gas facilities in most large older cities (particularly in the Northeast) account for the largest amounts of cast iron dating back before the turn of the 20th century. The cast iron system in National Grid's Boston Gas region is the second oldest in the United States (after Philadelphia Gas Works). The changeover from the use of cast iron to steel started slowly in the 1920s. During the 1940s, following the discovery of electric arc welding which provided a tight joint, steel pipe gradually replaced cast iron entirely. The industry has since replaced steel pipe with plastic pipe and cathodically protected coated steel pipe as the primary materials for distribution systems. Similar to unprotected or bare steel mains, the USDOT no longer permits installations of cast iron mains or service lines. ,

There are 18,322 miles of buried cast iron pipe still in service in the United States distributing natural gas as of 2021[1]. Much of this pipe has provided excellent service over its life. However, aging cast-iron mains have experienced gradual deterioration and are susceptible[2] to breaks, cracks, and other failures such as joint leaks.

As the owner and operator of nearly 21 percent of all the cast iron distribution main in the United States, National Grid has unparalleled experience in dealing with cast iron mains in a safe and reliable manner. Extensive research has been done throughout the years by National Grid's legacy companies and National Grid's cast iron replacement programs have been carefully designed to continue cost-effective operation in the safest and most reliable way possible.

In 2013, National Grid also participated in the development of an AGA white paper to Congress entitled "Managing the Reduction of the Nation's Cast Iron Inventory", which is incorporated here by reference.

[1] Source: US DOT Pipeline and Hazardous Materials Safety Administration Portal

[2] Other environmental effects, including methods used to support the pipe, frost, and vehicle loads that impose additional stress on the pipe, thus further reducing its useful life, exacerbate the deterioration caused by graphitization.

Experience from companies[3] that operate greater mileage of cast iron has identified certain parameters associated with higher leak and failure rates. Many of these parameters are useful to evaluate in identifying pipe segments more prone to failure. The predominant among these are:

- Pipe graphitization history
- Manufacture and original wall thicknesses, sometimes associated with vintage pipe diameter size and flexural resistance
- Loading and stresses associated with:
    - Operating pressures
    - Weather induced loads such as depth of winter frost penetration and frost action
    - Traffic loads
    - Construction impacts
    - Block supports
    - Settlement
    - Undermining
    - Washouts
    - Direct impact

Under research contracts with Cornell University that started in the early 1980's, the former Brooklyn Union (now part of National Grid) and other NY Gas Group companies sponsored research that has developed a library of technical papers on CI main condition, performance and evaluation. National Grid's Cast Iron related policies are informed by those studies, the most recent of which was prepared in 2008. National Grid's New York City Cast Iron system (the former Brooklyn Union Gas - which accounts for nearly 28% of all the Cast Iron in National Grid) dates from before 1895 through approximately 1950. After approximately 1930, centrifugally cast pipe predominates over pit-cast cast iron. Pit cast pipe was less uniform than later pipe, though out-of-spec wall thickness is rare. French cast iron piping of approximately WWI vintage has been reported to be overly brittle. Centrifugally cast pipe is theoretically more prone to stress crack corrosion according to UK studies, but that has not been recognized on the New York City system.

[3] A number of studies of cast-iron and factors affecting their service life have been made. A number of these studies and evaluations were made by ZEI, Inc. (formerly Zinder Eng Inc) Ann Arbor Michigan, including articles written; see Gas Industries, February 1986. The Department referred to this report in its February 28, 1991 Order concerning its investigation into proposed rules for cast iron.

6.2.2.2 Cast Iron Graphitization

NACE[4], in its Introduction to Corrosion Basics, 1984, pg. 216, states that the corrosion rate of cast iron is comparable to that of steel in a soil. The iron is removed from the metal, leaving a network of carbon particles by the de-alloying phenomenon termed graphitization. The residual carbon retains the form of the pipe, and unless the weakened pipe is fractured, the graphitized pipe will continue to transport gas. Once the cast-iron is graphitized, the exterior becomes an extremely noble electrode in any galvanic couple. Thus, uncoated or unprotected cast-iron or steel will act as the anode in contact with this "noble" pipe.

It should be noted that graphitization is still relatively infrequent within National Grid and only included here to demonstrate the Company's knowledge base. Experience shows that the soils in New York City and Long Island are the most benign with respect to graphitization. Upstate and New England soils appear to be somewhat more aggressive, though there does not appear to be much of a difference in the resulting frequency of graphitization.

Graphitization occurs when cast iron is exposed to certain types of corrosive environments over time. The resultant graphitization causes the beam strength to weaken and the pipe to become brittle and contributes to rates of broken mains. In its 1971-72 study of cast iron, the New York Gas Operations Advisory Committee report stated that its experience indicated graphitization was limited to certain specific localized environments. These were areas where there were localized salt water exposures or extreme stray current discharges (such as at substations and electrified rail transit systems).

Cast iron contains carbon, in the form of graphite, in its molecular structure. It is composed of a crystalline structure as are all metals (i.e., it is a heterogeneous mass of crystals of its major elements iron, manganese, carbon, sulfur and silicon). In the presence of acid rain and/or seawater, the stable graphite crystals remain in place, but the less stable iron becomes converted to insoluble iron oxide (rust). The result is that the cast iron piece retains its shape and appearance but becomes weaker mechanically because of the loss of iron.

Graphitization is not a common problem. It generally will occur only after bare metal is left exposed for extended periods, or where joints allow the penetration of acidic rainwater to internal surfaces. Therefore, there is a time dependency for graphitization to occur, and excluding other factors, the expectation would be that older pipes will have experienced deeper graphitic penetration and

[4] National Association of Corrosion Engineers.

disintegration. Soil moisture is normally enough to provide a conducting solution. This corrosion process is galvanic, with the carbon present acting as the noblest (least corrosive) element and the iron acting as the least noble (most corrosive) element. The composition or microstructure of the iron affects the durability of the object because the rate of corrosion is dependent upon the amount and structure of the graphite present in the iron.

Graphitic corrosion or graphitization[5] is a form of de-alloying or parting caused by selective dissolution of iron from cast iron (usually gray cast iron). It precedes uniformly inward from the surface, leaving a porous matrix of the remaining alloying element, carbon. Graphitization occurs in salt water, acidic mine water, dilute acids, and soils, especially those containing sulfates and sulfate reducing bacteria. There is no outward appearance of damage, but the affected metal loses weight, and becomes porous and brittle. The porous residue may retain appreciable tensile strength and have moderate resistance to erosion. For example, a completely buried cast-iron pipe may hold gas under pressure until jarred by a worker's shovel. Sulfates and sulfate-reducing bacteria in soil stimulate this form of attack.

6.2.2.3 Cast iron Pipe Support

A number of methods were used to install cast iron pipe sections. The most common method involved support of individual lengths of pipe with wooden or concrete blocks near each end. The blocks served to both support the main during construction and slope the pipe for proper drainage of manufactured gas liquids. Some installations included support near the center, placing pipe on mounds of earth instead of blocks, and still others directly on the trench bottom. Placing pipe on the trench bottom actually provides the greatest life expectancy as it minimized unsupported lengths of pipe, increased ability to withstand superimposed loads, and reduced beam action. Installation on wooden blocks has been seen to cause increased instances of graphitization at the point of contact between the cast iron and wood. There are no records indicating the method of installation; though at times, it can be inferred from the condition of the pipe. Block supports may also be detrimental when they cause pipe sections to behave as beams. All of these factors result in regionally higher break rates, which are used for identifying system replacement.

6.2.2.4 Cast Iron Pipe Size – Diameter and Flexural Resistance

Cast iron is more brittle and relatively weak as compared to steel. Sections of cast iron pipe supported at their ends on blocks experience loading and act as a beam. Flexural stress is created by the weight of

[5] NACE defines graphitic corrosion in its Introduction to Corrosion Basics 1984, at page 107.

the soil overburden, by the weight of the pipe itself, and by forces such as frost heave and other loads. Results of one study[6] to identify those main sizes that experience the highest failure rates revealed that 4", 6" and 8" diameter pipe accounted for 90% of the incidences of breaking and cracking. Said another way, the beam strength is much less for smaller diameters of cast iron pipe than for larger diameter pipe. There is an increase in relative beam strength for cast iron pipe with diameters equal to or greater than 10", providing some higher relative safety. In its system integrity analyses, National Grid regularly tracks the cast iron breakage "rates" on all of its systems and has found similar results.

While National Grid has not experienced extensive cast iron graphitization, it should be noted that cast iron pipe was installed bare and cannot be adequately protected by cathodic protection. Graphitization reduces wall thickness and thus reduces flexural resistance. An evaluation of flexural resistance (which is directly related to the "section modulus"[7]) demonstrates that a wall loss of 0.2 inch will result in a change in the relative section modulus of 4" through 8" diameter cast iron of between 45% and 52%. This reduced flexural resistance demonstrates that the smaller size pipes are far more susceptible to breakage than the larger size pipes.

Research performed by Cornell University identified 2000 micro strain as a critical level for cast iron pipe. For the purposes of replacement decisions related to parallel trench construction, 600-800 micro strain (0.06-0.08%) was selected as the replacement criteria. The condition of the cast iron pipe tested supported those levels as a proper margin of safety, which has been proven out by field experience under New York State PSC waiver and Massachusetts regulation.

When cast-iron main was originally installed as low pressure piping, its bell and spigot joints were filled with compacted jute backing and sealed with molten lead and lead caulking or cement. After years of service and switching from wet manufactured gas to natural gas, the jute has dried out and reduced in volume, weakening the seal within the joint. Additionally, exterior loads impact and flex the pipe and disturb the seal. Loads adversely impacting cast iron mains result from traffic, seasonal weather, vibration, and soil movements due to nearby construction activities; causing these joints to leak. Cornell observed that depending upon the diameter of the pipe, the joint contributed more or less to the flexibility of the pipe. Lead and jute joints were found to flex more than cement jointed pipe, which is

[6] 2007 Final Report on Peoples Gas Light and Coke Cast Iron Main Replacement – Kiefner and Associates, Inc.

[7] Section Modulus is a function of outside diameter, inside diameter, and wall thickness.

common on Staten Island in New York City. Lead joints were also seen to leak when flexed, and later creep and seal again in low pressure applications.

6.2.2.5 Cast Iron Bell Joints

Cast Iron and Ductile Iron gas mains are constructed with bell and spigot joints. These joints were most often sealed with jute and lead, cement, or encased in concrete in order to make the joint leak free and rigid. In many cases, bell joints have been retrofitted with mechanical bell joint clamps or bell joint encapsulation as a means of addressing bell joint leaks. In the New York City operating area (formerly Brooklyn Union), all joints on cast iron pipe operating at a 15 psig MAOP have been sealed with mechanical clamps or elastomers. A majority of the low pressure joints are sealed as well.

National Grid has used a number of methods to seal cast iron joints in past years. These methods fall into five broad categories and are listed below:

- Metallic Joint Clamps – A two-part clamp secured by bolts and designed to force a steel ring over the bell and spigot joint. Pressure from a rubber gasket presses on the circumferential lead face of the bell joint. One problem caused by this method of repair is that the steel clamp can become anodic to the cast iron, resulting in corrosion.
- Shrink Sleeves – Rubber/plastic materials used have varied as have the shrinking methods (electrical or thermal). A sleeve is fitted over a cleaned bell and spigot joint as well as a short section of pipe beyond the joint. The material is then essentially shrink fit to seal the joint. Extensive cleaning of the joint area is required and if performed incorrectly it can cause these to fail over time.
- Anaerobic Seals - These have had the advantage of exposing only the top part of the joint. A hole is drilled into the bell and an anaerobic sealant injected into the jute backing. The sealant material wicks into the jute and joint surfaces sealing the joint.
- Encapsulants - Also commonly called boots or muffs, encapsulate the face of the joint. This method is more effective than shrink sleeves and not subject to corrosion or gasket failure as is common with metallic clamps, nor are they as susceptible to improper installation.
- Internal sealing methods - There have been a few approaches used over the years, including internal clamping of the joint, fogging of the main, spraying the inside of the joint with an atomized sealer, mechanically applying a sealant of the joint and the internal pipe surface from within the pipe as well as pipe lining with a type of “innertube”.

Metallic Joint Clamps and Shrink Sleeves are no longer used, though metallic clamps that were properly coated are often found to be in good condition. Anaerobic seals are often selected when a large excavation is undesirable, exposing the entire joint is difficult or impossible, or in high water tables where it is difficult or disruptive to effectively encapsulate the joint. The current internal sealing method used is known as "CISBOT" and it has diameter, length and other limitations. Internal Lining is an expensive process, but adds other benefits. The best application for internal liners is on stretches of main without tie-ins or large numbers of services. Encapsulating bell joints is generally the most effective of the methods and the most commonly used. Many thousands of cast-iron joints are sealed every year in response to leaks. While this creates a high cost of operating and maintaining this class of asset material, leaking joints have rarely led to incidents.

6.2.2.6 Cast iron Loading and Impact

Cast iron is much more brittle than steel and is susceptible to cracks or breaks due to loading and impact. Main breaks are a major concern due to the large amount of gas that may be released in such instances. This is made worse when the driving force behind the cast-iron main leak is the operating pressure. Medium or high pressure cast iron aggravates the safety threat posed by cast-iron mains.

Cast iron breaks are often more severe than the typical corrosion leak. A cracked main may leak at a high rate, quickly saturating the area around the break with natural gas, migrating and entering conduits and following the path of other utilities to homes or other confined spaces such as utility vaults and sewers. Cast iron main breaks are of particular concern during periods of cold temperatures when frost actions may cause additional stresses on these mains and when frost caps create an impermeable barrier of the earth’s surface, preventing leaking gas from safely venting to the atmosphere. Such leaks may be difficult to pinpoint as they can cause high gas readings at appreciable distances from the actual leak site. The difficulty of leak investigation is aggravated under frost conditions and with depth of frost penetration. The inability of the gas to safely escape increases the risk to nearby residents, as gas follows the path of least resistance, often to nearby habitable structures.

The inventory of small diameter cast iron in National Grid’s service territory varies. Small diameter cast iron (8” and less) is most susceptible to bending stress and impact. National Grid policies define the replacement criteria for sound cast iron adjacent to parallel trenches or exposed due to crossing excavations. Additional consideration is given to conditions such as system performance and removal of pavement over shallow cast iron mains during road reconstruction.

6.2.2.7 Wrought Iron Pipe

In the National Grid territory, Wrought Iron was also used for both mains and services, although to a lesser extent than Cast Iron. Due to the lower carbon content compared to Cast Iron, Wrought Iron pipes are relatively malleable and do not exhibit the same body on pipe fracture mechanics common to Cast Iron. The method by which Wrought Iron pipe is joined also differs from Cast Iron, typically utilizing threaded or welded connections in addition to compression couplings which are not prone to the drying out that Cast Iron bell and spigot joints experience over time. However, Wrought Iron is still vulnerable to corrosion as are any/all pipes composed of iron and not cathodically protected.

While not vulnerable to the same unique threats posed to Cast Iron, Wrought Iron is still considered by National Grid to be an elevated risk and is actively replaced under the Leak Prone Pipe Program (LPP) due to the advent of improved material/construction standards and the long-term impacts of corrosion.

6.2.3 Plastic Pipe

Plastic pipe has a over 50 years of history. Various plastic piping materials were developed and introduced into the gas industry in the late 1960's and early 1970's. The industry became more focused on the corrosion and performance concerns with unprotected piping following the 1968 "National Gas Pipeline Safety Act". This required Federal regulations on Gas Transmission & Distribution systems in the U.S. and placed them under the jurisdiction of the Department of Transportation. Table 6-2 below is a summary of the plastic pipe materials that have been manufactured and marketed to the gas industry with a notation as to whether or not they are known to exist on the National Grid system.

The Company has included Aldyl-A as part of the leak prone pipe inventory and is scheduling for replacement. This includes plastic pipe installed pre-1985.

Table 6-2: Plastic Pipe Material Summary

Plastic Material Type	Known to Exist in the National Grid Gas System?
PVC – Polyvinyl Chloride	No
ABS – Acrylonitrile Butadiene Styrene	No
CAB – Cellulose Acetate Butyrate*	No
PB – Polybutylene**	Yes
PP – Polypropylene	No
PA – Polyamide	No
Century MDPE 2306	No
Aldyl-A (1972 and Prior) PE 2306	Yes
Aldyl-A (Post 1972) PE 2306	Yes
Aldyl-A (1973 and After) PE 2406	Yes
Aldyl 4A (green) PE 2306	Yes
MDPE 2406	Yes
MDPE 2708	Yes
HDPE 3306	Yes
HDPE 3406	Yes
HDPE 3308	No
HDPE 3408	Yes
HDPE 4710	Yes

* A limited number of 1-inch clear CAB services were installed in Upstate New York but have been reported to have been removed.

** Rhode Island only

NOTE: Fiberglass main was once used in MA, but has been completely removed to the best of our knowledge.

Table 6-3 below provides a summary of the currently approved plastic material types.

Table 6-3: Currently Approved Plastic Pipe Material Summary

Current Approved Plastic Material Type	Region(s)
PE 2708/PE 2406	NYC/LI
PE 4710	NYC/LI
PE 4710	UNY
PE 4710	RI
PE 2708	MA
PE 4710	MA

Details for plastic pipe by Company, Material designation, description, and Region are provided below in Table 6-4.

Table 6-4: Summary of Plastic Pipe by Region

Common Name	Company	Material Designation	Physical Description	Region(s)
Aldyl A*	Dupont Pipe	PE 2306 (pre-1973)	Pink, but can turn grey	LI, MA, NYC*, RI, UNY
Aldyl A*	Dupont Pipe	PE 2306 (1973 & later)	Pink, but can turn grey	LI, MA
Aldyl A*	Dupont Pipe	PE 2406 (1973 & later)	Pink, but can turn grey	LI, MA, NYC*, RI
Aldyl 4A	Dupont Pipe	PE 2306	Green	LI
CAB (Cellulose Acetate Butyrate)	Unknown	Unknown	Clear tubing	UNY***
Polybutylene	Clow Corp.	(1976 – 1979)	Tan	RI
Red Thread	Inner-tite	Epoxy-Fiberglass	Orange/red	NYC****, UNY
Inner-tite	Inner-tite	PE3306	Glossy Black	NYC,LI
Barrett	Barrett	PE3306	Glossy Black	NYC,LI
Orangeburgh	Orangeburgh	PE3306	Glossy Black	NYC,LI
Allied	Allied	PE3306	Glossy Black	NYC
Celanese Ultrablue	Celanese	PE 3306	Glossy Black	NYC
Crestline HD	Crestline	PE 3306	Glossy Black	UNY
Dupont HD	Dupont	PE 3406	Dull Solid Black	NYC**
Drisco 6500	Phillips Driscopipe	PE 2406	Orange	LI,MA,UNY
Drisco 6500	Phillips Driscopipe	PE 2406	Yellow	LI,MA,UNY
Driscoplex 6500	Performance Pipe	PE 2406/PE 2708	Yellow	LI,MA, RI
Drisco 7000	Driscopipe / Phillips	PE 3406	Solid Black	NYC, RI, UNY
Drisco 8000	Driscopipe / Phillips	PE3406/PE3408	Solid Black	NYC, MA,RI, UNY
Plexco	Plexco Pipe	PE2306	Orange	RI
Plexco	Plexco Pipe	PE2406	Orange	LI,MA
Plexco	Plexco Pipe	PE 2406	Yellow	LI,MA,RI
Plexco Yellowstripe	Plexco Pipe	PE 3406/3408	Black pipe with 4 yellow stripes	LI, MA, NYC,RI, UNY
Plexco Plexstripe II	Plexco Pipe	PE 3408	Black pipe with 2 yellow stripes	UNY

Common Name	Company	Material Designation	Physical Description	Region(s)
CSR Polypipe 4810	CSR Poly	PE 3408	Black pipe with 6 yellow stripes	UNY
Extron TR 418	Extron	PE 2306	Orange	UNY
Drisco/Performance Pipe 6800	Driscopipe / Phillips	PE 3408	Black with 3 yellow stripes	LI, NYC, UNY, RI
Drisco/Performance Pipe 8100	Driscopipe / Phillips	PE 3408/4710	Yellow exterior black pipe	NYC, RI, UNY
Performance Pipe 8300	Performance Pipe	PE 3408/4710	Black with 4 yellow stripes	LI, RI, UNY
US Poly UAC 3600 (formerly DuPont)	US Poly	PE 3408/ PE 3710	Black with 3 yellow stripes	LI, MA, NYC, RI, UNY,
US Poly UAC 3700 (formerly DuPont)	US Poly	PE 3408/4710	Black with 3 yellow stripes	LI, MA, NYC, RI, UNY,
JM Eagle UAC 3700 (formerly US Poly)	JM Eagle	PE3408/PE4710	Black with yellow stripes	LI, MA, NYC**, RI, UNY
UPONOR UAC 2000	DuPont	PE 2406	Yellow	LI, MA, NYC**, UNY
US Poly UAC 2000 - Formerly UPONOR	US Poly	PE 2406/PE 2708	Yellow	LI, MA, NYC, UNY
JM Eagle UAC 2000 (formerly US Poly)	JM Eagle	PE 2406/PE 2708	Yellow	LI, MA, NYC, UNY
Charter Plastics Inc	Charter Plastics Inc	PE 2406/PE 2708	Yellow	LI, MA, NYC
Charter Plastics Inc	Charter Plastics Inc	PE 3408/ PE 3608/ PE 4710	Black with 3 Yellow stripes	LI, MA, NYC, RI, UNY
Endot Bi-modal MDPE	Endot	PE 2406/PE 2708	Yellow	LI, MA, NYC,
Endot	Endot	PE 3408/ PE 4710	Black with 3 Yellow stripes	LI, MA, NYC, RI, UNY

* A very limited amount of Aldyl-A exists due to a trial installation in New York City.

** limited to Staten Island

*** A limited number of 1-inch clear CAB services were installed in Upstate New York but have been reported to have been removed

**** Limited to Greenpoint Area Only - RETIRED

6.2.4 Copper Pipe

Copper pipe was used for gas service lines in many service territories throughout the United States. Within National Grid's service territory, copper was predominantly used for service renewal by inserting copper inside of deteriorated steel services. In a much more limited manner, copper services were occasionally direct buried.

Copper services may be subject to leakage caused by corrosion. In particular, direct buried copper services may be subject to advanced rates of corrosion in the presence of dissolved salts in the soil (e.g., deicing salts to melt ice and snow on road surfaces).

Copper tubing is far less of a corrosion risk than steel—National Grid's corrosion experience with 116,814 copper services, which indicates less percentage of corrosion leaks associated with copper compared to all eight PHMSA threats.

When inserted in older steel services, the steel provides corrosion protection since the steel is more anodic than the copper. The older steel also protects the copper pipe from excavation, natural forces, and other damage. Corrosion on National Grid's copper services has been limited to locations where it was connected to dissimilar metal without insulating joints to provide isolation between the two dissimilar metals. The dissimilar metal is anodic to the copper and corrodes. The most common situation for this exists where copper is joined to an iron or bronze service tee (the iron tees are the most susceptible). Records of where and when these dissimilar metals were installed do not exist.

6.2.5 Instrumentation & Regulating Facilities

Instrumentation & Regulator stations is cover under National Grid's Station Integrity Management Program (SIMP).

6.2.6 Construction Methods

The existing National Grid distribution system is one of the oldest in the country and various methods of construction may have been utilized from time to time. Table 6-5 summarizes the types of construction Practices that have been used or practiced within the company's service territory.

Table 6-5: Construction Practices Summary

Construction Practice	Comment
Open trench installation	Yes
Support and Blocking	Yes
Service Replacement via insertion of Copper	Yes
Replacement of mains and services via Insertion of Plastic	Yes
Main Replacement via insertion and pipe splitting via PIM (Pipe Insertion Method)	Yes
Main Replacement via insertion and pipe splitting (static pipe bursting)	Yes
Internal lining / swage-lining / roll-down	Yes
Joint Trench with other utilities	Yes
Unguided Bore (e.g. Hole Hog)	Yes
Guided Directional Bore / Drill	Yes
Blasting	Yes
Plow-in	Yes

6.2.7 Excess Flow Valves

National Grid has implemented the recent Pipeline and Hazardous Materials Safety Administration (PHMSA) requirement of 49 CFR 192.381 Service Lines: Excess Flow Valve Performance Standards, and 192.383 Excess Flow Valve Installations. National Grid has been installing excess flow valves for new and replacement high pressure residential service lines in all areas since the early 1990’s and since the late 1970’s in NYC.

Ball type EFVs installed in the 1970’s has been found to be unreliable, but there have not been issues with the spring & plunger type. National Grid uses EFVs of various capacities, including branch service lines serving single family residence, multifamily residence, small businesses where they are compatible with load patterns and volumes. Refer to Table 6-7 for additional information.

Notifications to customers of their right to request installation of an EFV on service lines that are not being newly installed or replaced have been made through the Company’s website[8]. National Grid is in the process of developing a tracking and maintenance program for new or replaced service valves as required by 49 CFR 192.385 Manual Service Line Shut-off Valve Installation requirements.

[8] **Natural Gas Safety Links:**
https://www.nationalgridus.com/MA-Gas-Business/Natural-Gas-Safety/Pipeline-Safety
https://www.nationalgridus.com/NY-Home/Natural-Gas-Safety/
https://www.nationalgridus.com/RI-Home/Natural-Gas-Safety/

6.2.8 Mechanical Fittings

A summary of the known mechanical fittings currently in service is detailed below in Table 6-6.

Table 6-6: Mechanical Fittings

Mechanical Fitting Manufacturer	Type	Region
Perfection	Stab Fitting	All
Lyco	Stab Fitting	LI, RI
AMP Fittings	Stab Fitting	All
Reynolds	Nut-Follower	RI
ContinentalFittings	Stab Fitting	MA
Chicago Fittings	Nut-Follower	MA
ContinentalFittings	Nut-Follower	MA
Mueller w/ Dresser End	Nut-Follower	All
Normac	Nut-Follower	All
Dresser	Nut-Follower	All
Dresser	Bolted	All
Eastern	Bolted	All
Plidco	Bolted	LI, NYC, MA
Mueller	Bolted	All
Smith Blair	Bolted	All
CSI	Bolted	All
Dresser Posi-Hold	Hydraulic	All

6.3 Characteristics of Design, Operations and Environmental Factors

The characteristics of the pipeline's design, operations and environmental factors that are necessary to assess the applicable threats and risks are summarized in the following sections as well as Appendix A.

6.3.1 Operating Pressures and Gas Quality

National Grid's gas distribution pipeline system operates at various pressures from low to high throughout its service territory. Sources of gas include LNG and gas produced from natural underground reservoirs. Gas Quality is monitored and managed via National Grid's Transmission Integrity Management Program.

6.3.2 Reportable/Significant Gas Incidents

Detailed summaries of recent DOT reportable gas incidents are provided in Appendix A and were given the highest influence in the risk evaluation and prioritization. Table A-1 summarizes incidents by year for the past 30 years – with consequences. Table A-2 summarizes incidents by year for the past 30 years –

by cause. Additionally, details of last 10 years reportable incidents are provided in Table A-3 and the asset-threat combinations of all integrity-related incidents in that table were given a superseding influence in the risk ranking and prioritizations for that region. PHMSA reportable gas incidents are reviewed on a quarterly basis to determine the likelihood of such incident occurring in the National Grid's system and to create mitigation programs when necessary.

6.3.3 Gas Distribution Inventory and Repair Data

National Grid's Distribution Engineering Department is responsible for the development and implementation of Integrity Management Programs for Gas Distribution facilities. The department compiles and analyzes system and operating data, files annual reports to the Department of Transportation (DOT) and State regulators, generates periodic bulletins, and prepares various Integrity Reports and Analyses. In addition, the department measures System performance, analysis risk, performs data analysis, identifies threats, performs asset management, creates main & service replacement strategies and provides rate case support. The former Brooklyn Union committed to continuing to perform these sorts of analyses in an MOU issued to the New York State PSC in 1989 (although they were already a well-established routine by that time). These engineering and operational activities require knowledge of the system, including inventory age, annual system performance as well as performance trends over time.

A complete system inventory by material and size as well as leak repair data by cause is updated annually and submitted on the Annual DOT reports. Copies of the reports are available on Grid: Home on the Distribution Engineering page. Annual DOT reports are publicly available on PHMSA's website. National Grid Operator IDs are provided in Section **Error! Reference source not found.**.

6.3.4 Environmental Factors

National Grid operates gas distribution piping in some of the most populated regions of the country and where extremes weather exhibiting the four seasons are experienced. As such, all these factors are considered in the design, operation, and maintenance of the gas system. As previously noted in this section (Knowledge of Facilities) there are many different policies, piping materials and construction methods used. National Grid utilizes, where appropriate, the characteristics of the distribution system, design, operating, environmental, performance and physical testing and inspections to assess the applicable threats and risk to its gas distribution assets. The actual performance, testing and observed condition of the asset is directly related to the environmental conditions encountered. Other attributes that are considered in the risk can include asset class (main, service or I&R facility), material, size, pressure, construction method, or meter location (sub-classes). Environmental factors that have been considered in threat identification (see Appendix B) include seismic activity, earth movement, frost heave, heat sources, and flooding. Population density and other location-specific conditions are considered in National Grid's secondary, more detailed, risk ranking efforts at the segment level via the estimate of potential human exposure (in the building types and usage), following the preliminary assessment by asset class and subclass (region). National Grid's leak survey and surveillance practices take into account environmental factors such as susceptibility to leak migration (wall-to-wall paving or seasonal frost cap) and proximity to buildings of public assembly. Valves are located in a variety of environments, including areas of paved streets. Valves are operated and maintained in accordance with Policy CNST04009.

6.3.5 Gas Distribution Main and Service Assets Analysis

National Grid gas distribution system was constructed with the materials and methods described above over more than a century. The company reduces risk and threats by replacing the riskiest leak prone pipe where appropriate and through prudent operating and maintenance that includes a number of Preventative and Mitigative policies as noted in Table 6-1.

The National Grid Annual System Integrity Report is incorporated by reference into the DIM Plan and typically provides the following:

- Overall Regional Distribution Integrity Assessment Summary
- Total Leak Receipts – Current Year and Previous 9 Years
- Leak Receipts as a Function of Total System Pipe Mileage – Current Year
- Leak Receipts by Discovery Source (Excluding Damages) - Current Year and Previous 9 Years
- Leak Receipts by Original Classification (Excluding Damages) - Current Year and Previous 9 Years
- Year-End Workable (excludes Type 3) Leak Backlogs - Current Year and Previous 9 Years
- Year-End Open Type 3 Leak Inventories - Current Year and Previous 9 Years
- Performance Measure (Workable Backlog / Miles of System Pipe) - Current Year and Previous 9 Years
- Performance Measure (Type 3 Inventory / Mile of System Pipe) - Current Year and Previous 9 Years
- Main Inventory by regional Company- Current Year and Previous 9 Years
- Main age analysis by region - Current Year and Previous 9 Years

- Leak-prone pipe and Main replacement program - Current Year and Previous 9 Years
- Percentage of Leak-Prone Pipe - Current Year and Previous 9 Years
- Rate Case Supported Leak-Prone Main Replacement Levels
- Total Main Leak Repairs (Including Damages) - Current Year and Previous 9 Years
- Total Main Inventory by Material vs. Total Main Leak Repairs (incl. damages) by Material – Current Year
- All Main Leak Repairs by Material (Excluding Damages) - Current Year and Previous 9 Years
- All Main Leak Repairs (Including Damages) by Cause – Current Year
- Total Main Leak Rates (repairs per total mile of main) Including Damages - Current Year and Previous 9 Years
- Total Main Leak Rates (repairs per mile of total main) Including Damages - Current Year
- Main Leak Rates (Excluding Damages) by Material - Current Year and Previous 9 Years
- Current Year Main Leak Rates (Excluding Damages) – All Region Comparison by Material
- Main Leak Repairs – Material-Cause Matrix – Current Year
- 10-Year Cast Iron Main Inventory and Attrition Rate – All Region Comparison
- Total Cast Iron Main Breaks - Current Year and Previous 9 Years
- Cast Iron Main Break Rates – All Region Comparison by Diameter – Current Year
- 10-Year Bare/Unprotected Steel Main Inventory and Attrition Rate– All Region Comparison
- Main Corrosion Leak Rates - Current Year and Previous 9 Years
- Service Inventory by regional Company- Current Year and Previous 9 Years
- Total Service Leak Repairs (Including Damages) - Current Year and Previous 9 Years
- Total Service Inventory by Material vs. Total Service Leak Repairs by Material – Current Year
- All Service Leak Repairs (Excluding Damages) by Material - Current Year and Previous 9 Years
- All Service Leak Repairs (Including Damages) by Cause – Current Year
- Total Service Leak Rates (Including Damages) - Current Year and Previous 9 Years
- Total Service Leak Rates (Excluding Damages) by Material - Current Year and Previous 9 Years
- All Region Service Leak Rates (Excluding Damages) Comparison by Material – Current Year
- Service Leak Repairs Material-Cause Matrix – Current Year
- Distribution DOT Report data Comparisons – Current Year & Previous Year.
- System Integrity Report Analysis (Findings and Explanations)

The company has developed a procedure for selecting main segments for replacement. ENG04030: Identification, Evaluation, and Prioritization of Distribution Main Segments for Replacement. This procedure details the attributes that are considered and utilized, and they include but are not limited to Design, Operations and Environmental factors.

National Grid Damage Prevention metrics are also incorporated by reference into the DIM Plan and provide the following:

- Total Damages per 1000 Tickets
- Excavator Error Damages per 1000 Tickets
- Damages due to No-Calls per 1000 Tickets
- Damages due to Mismarks per 1000 Tickets
- Damages due to Company & Company Contractors per 1000 Tickets

(Note that "tickets" refers to all "one-call" requests, and not actual mark outs performed)

6.3.6 Gas Distribution Instrumentation & Regulation (I&R) Facilities Asset Analysis

Instrumentation & Regulator stations is cover under National Grid's Station Integrity Management Program (SIMP).

6.4 Additional Data Needed

Additional information needed that will be obtained over time through normal activities conducted on the pipeline is described in Table 6-7.

Table 6-7: Additional Information

Area of incomplete records or Knowledge	Can it be acquired over time through normal activities?	Does Action Plan Exist? Y / N	Scope	Schedule	Responsible Departments
Estimate number of EFVs • In system at CY end • Installed during the year on residential services only - NYS	Yes	Yes	• Data acquired through Electronic Records and GIS	• N/A	• Distribution Engineering
Above grade hazardous leak repair data on services – All Regions	Yes	Yes	Not previously included in DOT reporting. These leaks now need to be reported per latest OPS ruling	• Completed (2020 Annual DOT reporting)	• Distribution Engineering
Above grade leak repair data on I&R facilities – All Regions	Yes	Yes	Not previously included in DOT reporting unless leak tickets and leak numbers are generated. These leaks now need to be reported per latest OPS ruling	• Completed (2020 Annual DOT reporting)	• Distribution Engineering
Incorrect or Incomplete Facilities Records	Yes	Yes	• Employees may submit corrections to the AMMS system via Field Data	• Continuous	• Maps and Records

Area of incomplete records or Knowledge	Can it be acquired over time through normal activities?	Does Action Plan Exist? Y / N	Scope	Schedule	Responsible Departments
– Maps and Scanned Records – MA			Capture unit or the Maps & Records Data Correction Form. • Appropriate changes are made in ArcFM & SPIPE. Sketches are added to the Scanned Records system.		
Incorrect or Incomplete Facilities Records – Maps and Scanned Records – LI, NYC and UNY	Yes	Yes	• Employees may submit a corrected facility record per procedure CNST01005. • . • Appropriate changes are made in NRG and Fortis. Sketches are added to the Fortis system. • New mapping system (ArcGIS) implemented Fall 2021. As-built drawings are added to scanned record system.	• Continuous	• Maps and Records • Work Support • Asset Replacement

Area of incomplete records or Knowledge	Can it be acquired over time through normal activities?	Does Action Plan Exist? Y / N	Scope	Schedule	Responsible Departments
Incorrect or Incomplete Facilities Records – Maps and Scanned Records – RI	Yes	Yes	• Employees may submit corrections when inconsistencies are found per procedure CNST01005. • Appropriate changes are made in ArcGIS. Sketches are added to the Scanned Records system.	• Continuous	• Damage Prevention • Maps and Records

6.5 Data Capture for New Construction

The requirement for data capture for the location where any new pipeline is installed and the material of which it is constructed is contained in various standards as summarized in Table 6-8 below

Table 6-8: Data Capture Requirements

STANDARD	NYC	UNY	LI	MA	RI
GEN03002 Processing Gas Main and New Service Work Packages	x	x	x	x	x
CNST06020 Completion and Processing of Gas Service Record Cards	x	x	x	x	x
CNST01005 Preparation of Gas Facility Historical Records	x	x	x	x	x
Construction Documentation Specifications					x

6.6 Knowledge Capture – Subject Matter Experts

In addition to existing enterprise wide data, information, and reporting, National Grid has conducted additional interviews and discussions with process owners and regional groups of Subject Matter Experts (SME's) to determine if there are undocumented risks that could impact system performance. SME's are individuals who have specialized knowledge based on their experience or training. SME's were used to supplement existing, incomplete, or missing records and may be the only or best source of information in subjects such as historical operations, maintenance, and construction practices. SME interviews were also utilized to ensure that all threats have been identified. All SME interviews have been documented and stored in the Distribution Integrity Management Program files.

It should be noted that, due to the extent of National Grid's gas delivery systems over eight (8) legacy companies, SME interviews needed to be limited in order to accomplish implementation of the Plan within the necessary time frame. SMEs were selected based on experience and knowledge of general regions. It was not possible to include operations personnel from all geographic locations in each legacy company. To ensure that all reasonable threats were identified and evaluated, the summary SME data was carefully reviewed after the first issuance of the Plan. If anything was believed to be incorrect by the engineering SME panel or any regulator, that information was corrected in the current revision.

Furthermore, after the Plan is audited by regulators in all states, a more detailed rollout will be conducted with Operations and feedback will be solicited and incorporated into a future revision, as appropriate.

6.6.1 Bi-Annual Meeting

Threats, or Abnormal Operation Conditions (AOC), are continually being identified by Corrosion, Construction, Field Operations, and Material's Lab. Gas Distribution Engineering (GDE) has established a formal bi-annual meeting with SME's from the various service territories to provide updates on the Engineering Organization, Distribution Engineering Management Program, review of 10 year Trends and system performace, DIMP Threat Remediation Programs, Procedure Updates, AOC methodology to determine emerging threats and to gain Subject Matter Expert Feedback. The presentation utilized for the DIMP Bi-Annual meeting is stored in the GDE share drive.

7.0 THREAT IDENTIFICATION

The objective of this section of the plan is to identify existing and potential threats to the gas distribution pipeline. The following categories of threats shall be considered for each gas distribution pipeline:

- Corrosion Failure
- Natural Forces Damage
- Excavation Damage
- Other Outside Force Damage
- Pipe, Weld or Joint Failure
- Equipment Failure
- Incorrect Operation
- Other Cause concerns that could threaten the integrity of the pipeline.

In addition to the above categories established by §192.1007(b), National Grid may collect and assess threats by other additional categories to evaluate the system, trends, and risk. The Leak Cause categories and definitions per PHMSA OMB No. 2137-0629 are summarized below.

Corrosion Failure

A leak caused by galvanic, atmospheric, stray current, microbiological, or other corrosive action. A corrosion release or failure is not limited to a hole in the pipe or other piece of equipment. If the bonnet or packing gland on a valve or flange on piping deteriorates or becomes loose and leaks due to corrosion and failure of bolts, it is classified as Corrosion. (Note: If the bonnet, packing, or other gasket has deteriorated to failure, whether before or after the end of its expected life, but not due to corrosive action, report it under a different cause category, such as Incorrect Operation for improper installation or Equipment Failure if the gasket failed)

Excavation Damage

A leak resulting directly from excavation damage by operator's personnel (oftentimes referred to as “first party” excavation damage) or by the operator’s contractor (oftentimes referred to as “second party” excavation damage) or by people or contractors not associated with the operator (oftentimes referred to as “third party” excavation damage). Also, this section includes a release or failure determined to have resulted from previous damage due to excavation activity. For damage from outside forces OTHER than excavation which results in a release, use Natural Force Damage or Other Outside Force, as appropriate.

Equipment Failure

A leak caused by malfunction of control/relief equipment including valves, regulators valves, meters, compressors, or other instrumentation or functional equipment, Failures may be from threaded components, Flanges, collars, couplings and broken or cracked components, or from O- Ring failures, Gasket failures, seal failures, and failures in packing or similar leaks. Leaks caused by overpressurization resulting from malfunction of control or alarm device; relief valve malfunction: and valves failing to open or close on command; or valves which opened or closed when not commanded to do so. If overpressurization or some other aspect of this incident was caused by incorrect operation, the incident should be reported under “Incorrect Operation.”

Pipe, Weld or Joint Failure (All Materials, Including Plastic)

A leak resulting from a material defect within the pipe, component or joint due to faulty manufacturing procedures, desing defects, or in-service stresses such as vibration, fatigue and environmental cracking. Material defect means an inherent flaw in the material or weld that occurred in the manufacture or at a point prior to construction, fabrication or installation. Design defect means an aspect inherent in a component to which a subsequent failure has been attributed that is not associated with errors in installation, i.e., is not a construction defect. This could include, for example, errors in engineering design. Fitting means a device, usually metal, for joining lengths of pipe into various piping systems. It includes couplings, ells, tees, crosses, reducers, unions, caps and plugs. Any leak that is associated with a component or process that joins pipe such as threaded connections, flanges, mechanical couplings, welds, and pipe fusions that leak as a result from poor construction should be classified as “Incorrect Operation”. Leaks resulting from failure of original sound material from applied during construction that caused a dent, gouge, excessive stress, or other defect, including leaks due to faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site that eventually resulted in a leak, should be reported as “Pipe, Weld or Joint Failure”. force

Natural Forces Damage

A leak caused by outside forces attributable to causes NOT involving humans, such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, high winds (Including damage caused by impact from objects blown by wind), or other similar natural causes. Lightning includes both damage and/or fire caused by a direct lighting strike and damage and/or fire as a secondary effect from a lightning strike in the area. An example of such a secondary effect would be a forest fire started by lightning that results in damage to a gas distribution system asset which results in an incident.

Other Outside Force Damage

A leak resulting from outside force damage, other than excavation damage or natural forces such as:

• Nearby Industrial, Man-made or Other Fire/Explosion as Primary Cause of Incident (unless the fire was caused by natural forces, in which case the leak should be classified Natural Forces. Forest fires that are caused by human activity and result in a release should be reported as Other Outside Force),

• Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation. Other motorized vehicles/equipment includes tractors, mowers, backhoes, bulldozers and other tracked vehicles, and heavy equipment that can move. Leaks resulting from vehicular traffic loading or other contact (except report as “Excavation Damage” if the activity involved digging, drilling, boring, grading, cultivation or similar activities.

• Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels so long as those activities are not excavation activities. If those activities are excavation activities such as dredging or bank stabilization or renewal, the leak repair should be reported as “Excavation Damage”.

• Previous Mechanical Damage NOT Related to Excavation. A leak caused by damage that occurred at some time prior to the release that was apparently NOT related to excavation activities, and would include prior outside force damage of an unknown nature, prior natural force damage, prior damage from other outside forces, and any other previous mechanical damage other than that which was apparently related to prior excavation. Leaks resulting from previous damage sustained during construction, installation, or fabrication of the pipe, weld, or joint from which the release eventually occurred are to be reported under “Pipe, Weld, or Joint Failure”. Leaks resulting from previous damage sustained as a result of excavation activities should be reported under “Excavation Damage” unless due to corrosion in which case it should be reported as a corrosion leak.

• Intentional Damage/. Vandalism means willful or malicious destruction of the operator’s pipeline facility or equipment. This category would include pranks, systematic damage inflicted to harass the operator, motor vehicle damage that was inflicted intentionally, and a variety of other intentional acts.

• Terrorism, per 28 C.F.R. § 0.85 General functions, includes the unlawful use of force and violence against persons or property to intimidate or coerce a government, the civilian population, or any segment thereof, in furtherance of political or social objectives.

• Theft. Theft means damage by any individual or entity, by any mechanism, specifically to steal, or attempt to steal, the transported gas or pipeline equipment.

Incorrect Operations

A leak resulting from inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error. It includes leaks due to improper valve selection or operation, inadvertent over pressurization, or improper selection or installation of equipment. It includes a leak resulting from the unintentional ignition of the transported gas during a welding or maintenance activity.

Other Cause

Leak resulting from any other cause not attributable to the above causes. A best effort should be made to assign a specific leak cause before choosing the Other cause category. An operator replacing a bare steel pipeline with a history of external corrosion leaks without visual observation of the actual leak, may form a hypothesis based on available information that the leak was caused by external corrosion and assign the Corrosion cause category to the leak.

USE THIS CAUSE FOR ALL CAST IRON JOINT LEAKS – Including those which re-occurred because a failed joint clamp or seal.

7.1 Means of Threat Identification

National Grid's records and employees provide the basis of information regarding the system assets and materials. The cause categories noted above are the threats for gas distribution pipelines. The 5 year summary of the leak causes as reported on the annual DOT reports is incorporated by reference into this DIM Plan (refer to Apppendix E).

In an effort to gain additional information about the gas system and to identify potential unknown threats, Subject Matter Expert (SME) interviews were conducted and are summarized in Appendix B. Subsequent threats shall be identified as they are discovered or identified and reviewed by Integrity Engineering for inclusion into the Program.

A review of information gathered for Section 6.0 shall be conducted periodically to identify existing and potential threats. Threats (including material performance concerns) shall subsequently be identified by personnel who are knowledgeable of the National Grid system, operations and the Distribution Integrity Management Program. This is accomplished through the annual system integrity report that is prepared and issued by Distribution Engineering and is incorporated by reference into the DIM Plan. An annual review of the system performance combined with knowledge of the facilities, design, materials science, engineering, operation and maintenance histories, construction methods, environmental factors and an understanding of reportable/significant gas incidents provides National Grid with a sound indication of the threats to its system.

7.2 Monitoring Potential Threats

Potential Threats include those that are not currently evident based on National Grid gas distribution system failures, leak, or incident data. National Grid routinely monitors information from sources that may include:

- National Transportation and Safety Board (NTSB) Reports and Recommendations applicable to Pipeline Accidents.
    - Reports may be found at: https://www.ntsb.gov/Pages/home.aspx
    -
    - Recommendation Letters may be found at: https://www.ntsb.gov/Pages/home.aspx
- Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) Advisory Bulletins: http://www.phmsa.dot.gov/pipeline/regs/advisory-bulletin

- Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incidents: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
  Reported failures attributed to the gas distribution system are analyzed on a quarterly basis.
- Membership in a local, regional, or national gas association (e.g. American Gas Association, Northeast Gas Association, NACE, ASME, etc.) and involvement in Association workshops and forums that share knowledge regarding distribution pipeline threats
- Review of trade journals and magazines that publish material regarding gas distribution
- Incident Analysis (IA's) or Near Miss Reviews
- Leak Repair Data
- Mechanical Coupling / Fitting failure reports
- Process Safety Reporting
- All Failure Analysis Reports from the Materials, and Testing Group (M&T) are reviewed by Distribution Engineering and key failure data is entered into a Failure Analysis Database, which is used to identify any potential systemic integrity issues. Whenever an issue is discovered, even if it is not attributable to any asset subclass in the risk ranking (e.g. – common substandard conditions, fittings, etc.), appropriate mitigative measures are developed and implemented regionally or organizationally (depending on the nature of the issue). To further enhance the accuracy of the Failure Analysis Database, details of plastic leak data from all regions are scanned quarterly to identify any failures that may not have been sent in for analysis.

For material failures including mechanical fittings, a database was created where material failures are tracked. The following requirements have been incorporated into the gas operating procedure GEN01009, Reporting Nonconforming Material:

- Operations and Construction enters the material failure data into the non-conforming material database and sends failed specimen, when applicable, to the Materials & Testing Lab for evaluation.
- Operations and Construction will notify Distribution Engineering immediately if the failure is potentially systemic in nature, requiring immediate follow-up.
- M&T Lab will review the form, examine the material, perform any necessary testing, notify manufacturers and/or vendors when applicable. Standards and Work Methods issues any

necessary technical bulletins, product advisories or reports containing the lab's findings, recommendations and required follow-up actions.

- M&T will make all necessary filings with the AGA, PPDC and Public Service Commission.
- M&T will forward the form and report to Distribution Engineering for appropriate filing with PHMSA and advise Distribution Engineering if the investigation deems that immediate or scheduled removal of in-service material is warranted.
- Also, under "Reporting Nonconforming Material GEN01009 ", other potential threats (beyond mechanical fitting failures) are reported to and investigated by M&T and the follow-up is similar.

8.0 EVALUATION AND RANKING OF RISK

8.1 Objective

Risk analysis is an ongoing process of understanding what factors affect the risk posed by threats to the gas distribution system and where they are relatively more important than others. The primary objectives of the evaluation and ranking of gas distribution risk are:

- Consider each applicable current and potential threat
- Consider the likelihood of failure associated with each threat
- Consider the potential consequences of such a failure
- Estimate and rank the risks (i.e. determine the relative importance) posed to the system
- Consider the differences in the relevance of threats in areas among the various regions

For the purposes of risk assessment, National Grid has separated its gas distribution system into two broad (and very different) asset categories; Mains & Services and Instrumentation & Regulation Facilities. Separate models have been developed to estimate and relatively rank the risks for each of the assets (by sub-category). The models are different and completely independent of one another. The models and the results of these models are maintained by Distribution Engineering and Pressure Regulation Engineering and are used to develop National Grid's Asset Management Strategies by State and by Operator ID.

8.2 Mains & Services

For mains and services (with service lines including all equipment upstream of customer-owned piping, with "service line" as defined in Section 5.0), because of their sheer volume and non-homogenous nature, National Grid has elected to divide these assets into "regions" (segments of the system with similar characteristics and reasonably consistent risk for which similar actions would be effective in reducing risk). For purposes of the mains and services model, the "regions" will be the asset subclasses. The asset is first broken into two general facilities – mains or services. Each facility is further broken down by such factors as material (including active/inactive status, pipe coating, and cathodic protection status), inside vs. outside meter set (for services), pressure and diameter (for mains).

Diameters for pipe are classified by the following diameter ranges: up to 4-inch (small fractional wall thickness), over 4-inch and up to 8-inch (nominally ¼-inch wall), and over 8-inch (0.375-inch wall). For iron pipe (cast and wrought), diameters are classified by the following diameter ranges: less than 4-inch (with a higher break rate), 4-inch to 8-inch, and greater than 8-inch (with a lower break rate).

All plastic pipe evaluated in the model is assumed to be Polyethylene. As covered in Section 6.2.3, there may be small quantities of CAB in Upstate NY and PB in RI. To address any potential risk associated with these materials, company policy requires that all integrity-related plastic pipe failures be reported to the M&T lab for evaluation and monitoring for possible systemic issues.

A relative risk score is calculated for each asset subclass (with the main and service facilities ranked independently) for each of the eight defined threat categories. The risk ranking method for each asset subclass and threat consists of 4 parts: likelihood of failure and release of gas, likelihood of the release resulting in ignition, reduction controls and the potential consequences of such an event.

A separate score is calculated for each asset subclass and threat category. The highest scores (separately for mains and services) are identified for each region and then reviewed by an engineering SME panel in order to validate/adjust the model results. Some asset subclass/threat category scores were removed if the panel concluded that the high scores were the result of known data anomalies. Additionally, some asset subclass/threat categories with lower scores were added if the SME panel felt that the potential risk or exposure was not adequately represented by the calculations. Further, any asset subclass/threat category that experienced a reportable integrity-related incident within the prior ten (10) calendar years had its score changed in its respective region to “Known Incident”. (If the asset subclass/threat was not among the top risks listed, it was added to the list with a score of “Known Incident”.) All scores labeled “Known Incident” were then accelerated to the top of the risk rankings. The resulting final main and service lists of the highest risks for each region appear in Appendix C. The model and these lists will be updated annually based on the inventory and performance data for the previous calendar year.

It is not possible for National Grid to utilize operating environment factors such as known soil conditions, frost heave susceptibility, depth of cover, potential "other outside force damage" sources, potential "natural force damage" sources, geological conditions, paving, population density, building types, substandard conditions, etc. in its primary risk rankings (beyond the overall asset subclass general susceptibilities to "natural force" and "other outside force" damages); as these are very specific to geographic areas and can vary widely within even a small geographic region. As a result, National Grid's DIM Plan ranks risk by dividing its mains and services into "regions" with similar characteristics (as previously described). These types of factors, when known, are all considered when evaluating and prioritizing assets for proactive replacement as a mitigative measure. National Grid utilizes a secondary methodology for replacement qualification and prioritization (ENG04030) (see Section 6.3.4) that is risk-based and applied on a segment-by-segment level. Wherever possible, this methodology allows for accounting of environmental and other location-specific factors in the qualification and prioritization algorithms. These algorithms also include a "DIMP Factor" (which is based on the highest risk scores for that region in the DIM Plan) to increase the scoring for those asset subclasses and subsequently accelerate their attrition.

The parts (or "factors") used for risk ranking have been carefully designed to take advantage of known differences in the asset subclasses, extensive experience in failure modes and subsequent events, actual current performance data for the asset subclasses and threat categories, subject matter expert opinion on assets and failures experienced throughout the history of the company, existing system operational procedures, and populations affected by each threat. Some of these factors are variable (and will be updated on an annual basis), while others are relatively fixed. The factors and their components are detailed as follows:

- Likelihood of Failure and Release of Gas – There are two components to this. The first is the actual failure frequency (or leak repair rate) for the most recent calendar year. This is a variable factor that will be updated annually. The second is a rating applied from the results of subject matter expert interviews. This strengthens the likelihood calculation because it accounts for infrequent failures that may not occur on a consistent basis. It also was derived from extensive questioning on not only each threat category, but of all the known sub-threats for each category. This is a comparatively fixed factor.
- Likelihood of the Release Resulting in an Ignition – There are 2 components to this factor as well. The first involves the hazardous nature of all failures. This will be determined by the percentage of all leak discoveries that are Type 1 (hazardous). This varies widely within National Grid's companies. This will be a variable factor and will be updated on an annual basis. The second component will be a failure mode factor, which will be a fixed score assigned based on the most common mode of asset failure.
- Separate failure mode factor scores were identified by an engineering SME panel and will be assigned based on the asset and threat category.

- Additionally, reduction factors were included to this category for "controls" that are in place to reduce the likelihood of a release resulting in ignition. Extreme care was utilized not to include any controls that would have already been accounted for by the actual failure frequencies (leak rates). There was one control reduction factor applied to select services and one to select mains:
    - SERVICES – A reduction factor was applied to all non-LP operating greater than 10 psi services to account for the likelihood reduction due to the presence of excess flow valves (EFVs). The factor was different for each region, based on the percentage of those services which had been equipped with an EFV.
    - MAINS – A set of reduction factors was also applied to all Local Transmission mains. These factors are the same for each region but vary by threat category. They were applied to account for the fact that these mains were designed and constructed as Transmission mains and are operated, maintained and monitored as Transmission mains as well; thereby reducing the likelihood.

- Potential Consequences – The Health & Safety consequence is given a weight of 60% of the total consequence score, while Customer Interruption is given a weight of 20% and Regulatory & Reputational Impact and Asset Impact consequences are weighted at 10% each.

The data used in the mains & services risk assessment is consistent with the data reported to PHMSA in National Grid's Annual Gas Distribution Reports.

8.3 Pressure Regulation

National Grid utilizes a risk model to evaluate, and risk ranking information is covered under National Grid's Station Integrity Management Program (SIMP).

9.0 IDENTIFICATION AND IMPLEMENTATION OF MEASURES TO ADDRESS RISKS

The objective of this section of the DIM Plan is to describe existing and proposed measures to address the risks that have been evaluated and prioritized in Section 7.0. National Grid has a number of Corporate and Gas Business programs and initiatives to minimize risk to the company, the customers and the public.

9.1 Corporate Culture Philosophy and Programs

National Grid recognizes that the energy it provides is essential to today's society, but that it has inherent risk which cannot be completely eliminated. The risk can however be managed and kept as low as reasonably possible. These programs and initiatives, in most cases, exceed existing gas safety regulations and position National Grid to be a premier energy company. These programs and initiatives include but are not limited to the following:

- *Asset Management* and Engineering

National Grid has adopted the Business Management System (BMS). At National Grid, asset management and engineering are vital to delivering safe, efficient, reliable and environmentally sound performance in each of its lines of business.

Safety Management System - National Grid has implemented a Safety Management System (SMS) based on the American Petroleum Institute Recommended Practice 1173 (API RP 1173). The SMS provides a framework to house all relevant activity under ten prescribed elements**:**

1. **Leadership and Management Commitment:** Puts the National Grid's commitment to improve pipeline safety into formal practice
2. **Stake Holder Engagement:** Build relationships both internally and externally to support the safety of our system and operations
3. **Risk Management:** Manages the Company's assets and operations using a risk-based approach
4. **Operational Controls:** Integrates all aspects of the Company's operations into a single, umbrella framework, providing a disciplined and formal method to communicate and manage standard ways of working.
5. **Incident Investigation, Evaluation, Lesson Learned:** Provides the basis for learning and continuously improve from the review and feedback from incidents
6. **Safety Assurance:** Measures and assess pipeline safety risk and compliance issues
7. **Management Review and Continuous Improvement:** Ensures that pipeline safety performance is reviewed, and continuous improvement actions are developed on an on-going basis

8. **Emergency Preparedness and Response:** Develops and practice readiness to response in the event of a pipeline incident
9. **Competence, Awareness and Training:** Design and deliver proper training and information to achieve a workforce that has the appropriate level of experience, knowledge and expertise
10. **Documentation and Record Keeping:** Manage documentation and record keeping to support pipeline safety decision-making and reporting

- *Damage Prevention* - National Grid follows the nine (9) elements contained within the published PHMSA Damage Prevention Assistance Program (DPAP). The Company has been actively involved in mark outs and damage prevention for over 25 years. National Grid also participates in the Common Ground Alliance DIRT program.
- *Gas Emergency Procedure Manual – A* Gas US manual that includes plans specifically developed to provide for a rapid emergency response. The program is designed to minimize the extent of an emergency.

- *Incident Investigation Program* –This program is intended to reduce the recurrence of injuries and incidents by identifying contributing factors and root causes, and then taking corrective actions that address the root causes. Using this program, personnel can help prevent repeat incidents, reducing risk of injury. this is the process necessary to ensure that injuries and serious incidents are analyzed thoroughly and promptly to avoid reoccurrence.

National Grid Safety Procedure J-1001 provides details on:

- How we ensure that injuries and serious incidents are investigated, and corrective actions are taken promptly, to avoid any recurrence.

- How the information derived from our investigations is communicated to the organization to ensure that the lessons learned through operating experiences can be utilized by others.

- *Leak Management Program* – National Grid's leak management program (see Table 6-1 for specific procedures) adheres to the following principles:

- Locate the leaks (leak response and leak survey)
- Evaluate the actual or potential hazards associated with these leaks
- Act appropriately to mitigate these hazards (including leak surveillance)
- Keep records; and
- Self-assess to determine if additional actions are necessary to keep people and property safe

- *Material Standards & Testing (MS&T)* - National Grid maintains its own materials lab that tests gas materials for compliance with standards and for suitability for its gas system. The lab also performs root cause analysis of materials failures and investigates issues with materials and tools. Findings often generate changes in manufacturers' products and QA/QC procedures. MS&T's role in investigating mechanical fitting failures and other non-conforming materials is described in Section 7.2.
- *Operator Qualifications (OQ)* – Representatives of The New England Gas Association, the regional trade association for 26 distribution companies operating in the 6 New England states, and the New York Gas Group, a regional trade association for 10 distribution companies operating in the state of New York, formed a consortium in 1999 to develop an operator qualification written plan. Those trade associations merged, and are now the Northeast Gas Association. The National Grid OQ committee has met quarterly to ensure the effectiveness of the OQ program. National Grid participates in meetings with all State Commission Staffs through the Northeast Gas Association's OQ Working Group (offspring of the two organizations mentioned previously).
- *Personnel and Job Site Safety* – This includes a core belief and commitment to Believe in Zero accidents, Employee Safety Handbooks, Trusted to Work Responsibly Documents, the Golden Rules of Safety, Job Briefing and Compliance Assessments.
- *Plastic Pipe Data Collection (PPDC) Initiative* – National Grid participates in the national effort to track plastic material failures and use that information to assess risk on plastic systems.
- *Proactive Main and Service Replacement Programs* – National Grid recognizes that over 26% of the mains and 22% of the services are made up of leak prone materials. Significant replacement plans are in place to reduce the inventory and thus the risk associated with leaks and cast iron breaks.

- Additionally, ENG04030 has been revised (Revision 4, effective 08/01/2020) to better address systemic issues on vintage plastic pipe, and the extent of replacement under such conditions.

- *Process Safety* – This program is based upon practices of the chemical industry and the Baker Panel investigation of the BP Texas City incident. It seeks to understand and manage the risk of low frequency high consequence events (i.e. fires and explosions). In addition to internal measures and the review of incidents and near misses, events external to the company are also reviewed (e.g., sewer cross-bore incidents, compression coupling failures, etc.). Over 100 Process Safety Key Performance Indicators (KPIs) are tracked and reported to the Board of Directors, covering the following twelve Elements of Process Safety.
    - Process Safety Leadership
    - Plant Design and Modifications
    - Operational Procedures
    - Workforce Competence
    - Human Factors
    - Emergency Arrangements
    - Protective Devices, Instrumentation and Alarms
    - Inspection and Maintenance
    - Permit to Work
    - Asset Records and Data Quality
    - Third Party Activities
    - Audit, Review and Closeout
- *Flooding* – National Grid has begun identifying its vulnerable facilities in flood-prone regions on both 100-year and 500-year flood surge maps, and will consider any appropriate safety and reliability improvements to those facilities.
- *Storm Hardening* – National Grid is currently evaluating various potential storm hardening measures.
- *Process Ownership* - National Grid has established process owners for various safety and management tasks to reduce risk by ensuring that best practices are reviewed and there is consistent reporting and tracking across all territories.

- *QA/QC* – National Grid has a Quality Assurance and Quality Control (QA/QC) group which monitors compliance with all gas regulatory requirements, as well as applicable National Grid construction, maintenance, service and safety policies. This effort involves:
  - Field inspection and assessment of National Grid personnel and contractors who routinely perform gas construction, maintenance and service activities;
  - Performing process audits involving Federal and State gas regulations;
  - Conducting additional audits for gas related activities on a regional basis, as well as those identified by the Business Management System (BMS) for having potential adverse risk to the Company's gas assets;
  - Utilize the Six Sigma process methodology to address companywide projects that require a detailed focus for inter related departmental issues;
  - Re-Dig program - this program targets post inspection results of completed gas facility installation and repair activities across National Grid's U.S. Gas Operations.
- *Gas Distribution Engineering Reporting* – Distribution Engineering tracks and produces regulatory reports for compliance with annual DOT and State reporting requirements. In addition, various in-depth reports on the system's performance are created to provide trending data. These reports are also used to measure and monitor the performance of existing programs.
- *Corrosion Control* – National Grid has established enterprise wide corrosion control standards, test instructions and policies covering the design, installation, surveys inspections, testing and monitoring of the cathodic protection on its gas system. These provide the preventative and mitigative actions necessary to address the threat of corrosion.
- *Special Patrols* – The local and non-IMP transmission lines are covered under this DIM plan. National Grid has established enterprise wide patrol policy CNST02005, Patrolling Transmission Pipelines. The policy covers the DOT transmission system and local transmission lines.
- The Standards, Policies & Codes area of National Grid's Gas Asset Management organization has developed a Pipeline Public Awareness (PPA) program as a result of the Pipeline Safety Improvement Act of 2002. The program encompasses all of National Grid's gas transmission and distribution facilities across New York, Massachusetts and Rhode Island. The goal of the program is to educate the general public about pipeline safety, including topics such as:
  - How to recognize possible leaks in gas pipelines and what to do if a leak is suspected

  - How to contact the pipeline operator in an emergency
  - The presence of buried gas pipelines in the communities served
  - The necessity to call before excavation – Know What's Below; Call Before you Dig – Call 811
  - The significant role the public/excavators can take in helping to prevent third-party damage accidents as well as how they should respond.
  - The proper actions emergency response agencies and first responders should take in response to a pipeline emergency
  - The means to assess the effectiveness of the communications used by the PPA Program, in order to improve the Program's effectiveness over time.
- The PPA program is managed within the Operations, Codes & Policies area of Gas Asset Management. There is a Committee that provides oversight to the program made up of:
  - Customer Communications
  - Community & Customer Management
  - Damage Prevention
  - Emergency Planning
  - Gas Work Methods
  - Learning & Development
  - Safety
- The PPA program has four key stakeholders:
  - Affected Public: Residents along a transmission pipeline right-of-way, places of congregation, near gas storage & operational facilities, along gas distribution lines as well as all National Grid customers should be educated on the appropriate actions and precautions to take while living in proximity of gas pipelines. This will in turn create a safer environment and allow for more reliable service.
  - Emergency Officials: Fire departments, police departments, Local Emergency Planning Management Agencies (EMA) and 911 call centers must be aware and educated on the safety measures and company plans while dealing directly with a gas pipeline emergency.
  - Local Public Officials: Mayors & administrators, zoning boards, public works officials, licensing & permitting departments, building code enforcement departments and public

officials must be educated and work alongside National Grid to ensure the safety and cooperation of the public.

- Excavators: Employees from construction, blasting, directional drilling and landscaping companies as well as farmers, sprinkler system installers and demolition teams all need to be aware of and educated on pipeline safety. This increased awareness and education will likely reduce the number of pipeline damages and accidental leaks.

National Grid's PPA Program communicates to these key stakeholder groups in a number of ways:

- Pipeline Public Awareness brochures included in customer bills
- Public service announcements
- Paid advertising
- Direct mailings with letters and safety brochures
- National Grid websites
- Links to other pipeline safety information sites
- Facebook
- Twitter
- On-line training programs for first responders and contractors dealing with natural gas and electric
- Education materials for elementary school teachers and students regarding natural gas and electric.
- Liaison meetings with emergency and local public officials
- Attendance at community events

- National Grid also participates in collaborative outreach to key stakeholders through the Northeast Gas Association using radio and cable television spots.
- The PPA program also communicates natural gas and pipeline safety information by direct mail outreach to excavators and in conjunction with the local Call Before You Dig call centers like Dig Safely, New York 811 and Dig Safe to provide natural gas safety and damage prevention information and training sessions.

9.2 Primary Threat Mitigation

National Grid worked with the American Gas Association (AGA) and the American Gas Foundation (AGF) on the development of an AGF Study on Distribution Integrity. This study was based on an analysis of gas distribution incidents in the DOT / OPS Database for the years 1990-2002. The study concluded that the top five (5) processes having the greatest impact on distribution integrity were:

- One Call / Mark Outs Systems to reduce third party damage
- Operator Qualifications to reduce operator error
- Cathodic Protection to reduce potential corrosion leaks or wall loss
- Leak Management to reduce the potential for leaks to cause an incident
- Proactive Replacement to reduce the inventory of problematic materials or components

National Grid also included construction activities in Operator Qualifications program early in its development. Additional or accelerated actions that have been taken or are being planned in order to reduce the risks from failure of the gas distribution pipeline are documented in Appendix D. These mitigation efforts address each of the primary threat types: corrosion, natural forces, excavation damage, other outside force, material or weld failure, equipment failure, incorrect operation, and other causes. National Grid's Distribution Engineering Department continuously monitors system performance in order to evaluate threats and also monitors gas industry best practices. As necessary, the Distribution Engineering Department will work with the Standards & Policy Department to update or issue new policies and procedures to mitigate threats.

9.2.1 Mitigation Program Tracker

Appendix D in the DIM Plan includes a description of all the National Grid's mitigation programs. Gas Distribution Engineering has established a monthly HUB where updates on DIMP mitigation programs are provided and reviewed.

10.0 MEASUREMENT OF PERFORMANCE, MONITORING RESULTS, AND EVALUATING EFFECTIVENESS

The objective of this section of the plan is to establish performance measures that shall be monitored from an established baseline in order to evaluate the effectiveness of the DIM Program. The performance measures detailed in Sections 10.1 through 10.6 have been established in order to monitor performance and assist in the ongoing evaluation of threats. Distribution Engineering shall aggregate data from various legacy data sources (and successor data systems) as necessary to track each performance measure.

10.1 Number of Hazardous Leaks Either Eliminated or Repaired, per §192.703(c), Categorized by Cause

National Grid has been tracking all leaks by material and cause since 2005, consistently monitoring trends. The baseline and ongoing performance of the number of hazardous leaks either eliminated or repaired, per §192.703(c), categorized by cause, shall be documented, or included by reference, in Appendix E, Section 1. The baseline for this performance measure shall be 5 years recorded performance. Recent improvements in data scrubbing and validation make 5 years performance the best baseline from which to monitor ongoing performance.

10.2 Number of Excavation Damages

Excavation Damage was defined in §192.1001 in December of 2009 with the publishing of the Final Distribution Integrity Management Rule. National Grid has been tracking and trending leaks associated with excavation damage since 2004; however the new definition of excavation damage goes beyond just leaks. Thus, the baseline for this performance measure will be 5 years performance. The baseline and ongoing performance of the number of excavation damages shall be documented, or included by reference, in Appendix E, Section 2.

10.3 Number of Excavation Tickets (Received from the Notification Center)

The baseline and ongoing performance of the number of excavation tickets received from the notification center(s) shall be documented, or included by reference, in Appendix E, Section 3. The baseline for this performance metric will be 5 years performance.

10.4 Total Number of Leaks Either Eliminated or Repaired, Categorized by Cause

National Grid has been tracking all leaks by material and cause since 2004, consistently monitoring trends. Recent improvements in data scrubbing and validation make 5 years performance the best baseline from which to monitor ongoing performance. The baseline and ongoing performance of the total number of leaks either eliminated or repaired, categorized by cause, shall be documented, or included by reference, in Appendix E, Section 4.

10.5 Number of Hazardous Leaks Either Eliminated or Repaired, per §192.703(c), Categorized by Material

National Grid has been tracking all leaks by material and cause since 2004, consistently monitoring trends. The baseline and ongoing performance of the number of hazardous leaks either eliminated or repaired, per §192.703(c), categorized by material, shall be documented, or included by reference, in Appendix E, Section 5. The baseline for this performance measure shall be 5 years recorded performance. Recent improvements in data scrubbing and validation make 5 years performance the best baseline from which to monitor ongoing performance.

10.6 Additional Performance Measures

As it is determined that additional performance measures are needed to evaluate the effectiveness of the DIM Program in controlling an identified threat, the performance measures shall be documented, or included by reference, in Appendix E, Section 6.

Additional performance measures initially established include:

- Workable Leak Backlog at the End of Year (known system leaks scheduled for repair)
- Total Excavation Damages per 1000 Tickets
- Main Leak Rates by Material Excluding Damages
- Service Repairs per 1000 Services by Material, Excluding Damages
- Total Leak Receipts
- Response Time Performance

National Grid monitors many other metrics in the course of conducting and monitoring operations and process safety. Extensive investigation/research, monitoring and improvement works are being performed on some special projects like Farm Tap investigation and design upgrades to new Process Safety Standards, Inner-Tite fitting Inspection, etc. All the reports are incorporated by reference in its most updated form. Additional performance measures may be added to Section 10.6 when warranted to control threats.

11.0 PERIODIC EVALUATION AND IMPROVEMENT

The objective of this section of the plan is to periodically re-evaluate threats and risks on the entire pipeline and periodically evaluate the effectiveness of its program.

11.1 Plan Updating and Documentation

This written integrity management plan shall be reviewed periodically and updated as required to reflect changes and improvements that have occurred in process, procedures and analysis for each element of the program. National Grid performs extensive trending and analysis annually and documents it in the System Integrity Report. Additionally, National Grid will update risk assessment and ranking by asset class on an annual basis. In addition to the annual efforts, a complete program re-evaluation shall be completed, at a minimum, every five years. All the DIM Plan changes and results are documented in a "Description of Change" report, which kept on the Gas Distribution Engineering Internal Share drive. The complete program re-evaluations shall address:

- Frequency of the next complete program re-evaluation based on the complexity of the system and changes in factors affecting the risk of failure
- Verification of general information
- Incorporation of new system information
- Re-evaluation of threats and risk
- Review the frequency of the measures to reduce risk
- Review the effectiveness of the measures to reduce risk
- Modification of the measures to reduce risk and refine/improve as needed
- Review performance measures, their effectiveness, and necessary improvements

Form F-1 in Appendix F must be used to document Periodic Review and Updating. All changes to the written plan, inclusive of material from the appendices, shall be recorded on the Revision Control Sheet on page ii. However, changes to material in the appendices that is included by reference need not be recorded on the Revision Control Sheet. This plan shall reside on the National Grid intranet with the accompanying change-management.

11.2 Effectiveness Review

An assessment of the performance measures described in Sections 10.1 through 10.5 shall be performed periodically. The National Grid System Integrity Report shall be prepared annually. The evaluation of threats and risks shall be performed annually. Other discretionary measures (mitigation beyond minimum code requirements) may be necessary and shall be assessed at the discretion of management. An emerging threat in one or more location shall be evaluated for relevance to other areas. If the reviews described above demonstrate significant changes to threats or system performance, a complete program re-evaluation may be completed in a shorter timeframe than five years. Form F-1 in Appendix F may be used to document Effectiveness Reviews.

12.0 REPORTING RESULTS

12.1 State & Federal Annual Reporting Requirements

The following shall be reported annually, by March 15, to PHMSA as part of the annual report required by 49 CFR, § 191.11:

- Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), per § 192.703(c), categorized by cause
- Number of excavation damages
- Number of excavation tickets (receipt of information by the underground facility operator from the notification center)
- Total number of leaks either eliminated or repaired, categorized by cause
- Total number of hazardous leaks involving a mechanical joint failure.
    - For Massachusetts Only: The Department of Transportation (MDPU) requires that information related to failure of mechanical fittings, excluding those that result in non-hazardous leaks, be reported no later than 15 days after determining a mechanical fitting failed.

These measures, as well as any others that may be required by the State, shall also be reported to the appropriate State Agency as per GEN01020 (incorporated by reference). A copy of the reports shall be maintained in the Distribution Integrity Management Program files.

13.0 DOCUMENT AND RECORD RETENTION

The following records shall be retained in the Distribution Integrity Management Program files.

- The most current as well as prior versions of this written DIM Plan and its Appendices
- Documents supporting Knowledge of Facilities (material supporting Appendix A of the DIM Plan as well as the annual System Integrity Report)
- Documents supporting threat identification (material supporting Appendix B of the DIM Plan)
- Documents supporting the identification and implementation of measures to address risks (material supporting Appendix D of the DIM Plan)
- Annual Reports to PHMSA (as required by §191.11) and State pipeline safety authorities
- Mechanical fitting Failure Reports

Documentation demonstrating compliance with the requirements of 49 CFR, Part 192, Subpart P shall be retained for at least 10 years. Table 13-1 summarizes a data matrix on records used, collection method, collection frequency, and storage location.

Table 13-1: Data Matrix for Collection Method and Storage Location

Source	Data Characteristics (192.1007(a)(1)) (Design, Operations, or Environment)	Asset Type	Collection Method/ Frequency	Storage Location	Region	Responsible Party	Description
As-Built Drawings	Design	Main	Paper and electronic/ completion of job	Gas System Engineering Sharedrive	NY LI Upstate MA RI	Construction / Field Operation	Material, installation method, Installed Date, material, pressure, Pressure Test, Pressure test duration, material, pressure, diameter, , segment length, construction method, foreman, spatial placement, fitting information, Depth of Cover, Easement, Pipe grade,
	Design	Service	Paper and electronic/ completion of job	Fortis for > 2" NPS MDSI for < or = 2" NPS MA & RI Iron Mountain	NY LI Upstate MA RI	Construction / Field Operation	Material, installation method, Installed Date, material, pressure, Pressure Test, Pressure test duration diameter, segment length, construction method, foreman, spatial placement, fitting information, Depth of Cover, Easement, Pipe grade, Meter Location, Service Valve Installed, Meter Protection, EFV Installed, Cathodic Protection, Pipe Abandoned, Meter Capacity, Tracer Wire
GIS	As- Built Drawings	Main	Electronic/ updated as new information becomes available	NRG NRG GIS-Esri ArcFM GIS-Esri	NY LI Upstate MA RI	Mapping	Distribution assets: Work Order, Date Installed, Vintage Date, Location, Diameter, Install Method, Material, Length, Cathodic Protection Status, Pressure Classification, Joining Method, Coating Type
	As- Built Drawings	Service	Electronic/ updated as new information becomes available	NRG NRG Smallworld SPIPE GIS-Esri	NY LI Upstate MA RI	Mapping	Distribution assets: Work Order, Date Installed, Vintage Date, Location, Diameter, Material, Length, Cathodic Protection Status, Pressure Classification, Joining Method, Coating Type
DIMP Bi-Annual Meeting	Design, Operations, Environment	Main/ Service	Electronic meeting minutes	DIMP Sharedrive	NY LI Upstate MA RI	DIMP	Bi-Annual Meeting with NGrid SMEs - Review Distribution10 years Trends for System Performance, overall review of PHMSA reportable incidents, Engineering Organization, Distribution Engineering Management Program Overview, Threat Remediation Program, Procedure Updates, Subject Matter Expert Feedback.

Source	Data Characteristics (192.1007(a)(1)) (Design, Operations, or Environment)	Asset Type	Collection Method/ Frequency	Storage Location	Region	Responsible Party	Description
PHMSA Bulletins	Design, Operations, Environment	Main/ Service	Electronic	https://www.phmsa.dot.gov/regulations-fr/notices	NY LI Upstate MA RI	Gas Process Safety / Compliance	The safety compliance distributes the bulletins to the appropriate departments
National Weather Service	Environment	Not Applicable	Electronic	DIMP Sharedrive	NY LI Upstate MA RI	DIMP/ Field Operations	Weather Forecast information is used to initiate winter leak operations.
PHMSA Reportable Incidents	Design, Operations, Environment	Main/ Service	Paper and electronic/ As needed	DIMP Sharedrive- Incidents as of 2010	NY LI Upstate MA RI	DIMP	The criterion to report incident to PHMSA, if as follow: 1 - Any fatalities or Injuries are involved 2- Estimated property damage of $50,000 or more 3- Unintentional estimated gas loss of three million cubic feet or more 4- An event that is significant in the judgment of the operator, even though it did not meet the criteria listed above (1,2,3)
Incident Management System (IMS)	Operations	Main/ Service	Electronic	DIMP Sharedrive	NY LI Upstate MA RI	DIMP	Incident Management System (IMS) - IMS Safety, Health and Environmental Services' online management tool. IMS which allows the reporting of safety and environmental-related incidents, perform incident analysis. GDE reviews all reported Incidents and take necessary actions as needed.
Quarterly Google News Alert (Incidents)	Knowledge	Main/ Service	Electronic	DIMP Sharedrive	NY LI Upstate MA RI	DIMP	Utilize Google Alerts to perform keyword search in news articles for potential gas incidents. GDE review all US incidents on quarterly bases for existing and new threats

Source	Data Characteristics (192.1007(a)(1)) (Design, Operations, or Environment)	Asset Type	Collection Method/ Frequency	Storage Location	Region	Responsible Party	Description
Leak Survey Plan	Operations	Main/ Service	Refer to NY,MA, RI procedures for collection method and Frequency	Fulcrum	NY LI Upstate MA RI	Field Operations	1- Distribution Survey-Walking: Main and service leakage surveys shall be conducted at least once every three calendar years. 2- Distribution Survey-Mobile (NYC ONLY): In New York City, a mobile leakage survey shall be conducted once per calendar year and at intervals not to exceed 15 months. 3- Business District Survey: Conducted in company designated business districts, at intervals not to exceed 15 months. 4- Winter Patrol Surveys: Conducted during company defined frost periods for company designated segments of the distribution system. Piping subject to the cast iron encroachment plan shall be surveyed for leakage daily until the main is replaced. As requested surveys - shall be performed based on demand. 6- Special Surveys: As requested surveys - shall be performed based on demand.
Leak Management System	Operations	Main/ Service	Electronic	Maximo, CWQ Maximo, LMS GAM LMS New Maximo, GIS (DIMP Sharedrive)	NY LI Upstate MA RI	DIMP	Class 1, 2, and 3 leaks information and repair status for Quarterly PSC Reports, Yearly DOT, System Integrity, DIMP
Pipeline Patrol	Operations, environment	Main	Weekly but not to exceed 10 days	Damage Prevention GFO I&R I&R I&R	NY LI Upstate MA RI	Field Operation	Pipeline operating at >124 psi Patrolling Transmission Pipelines CNST02005 Patrolling Mains in Hazardous Locations CNST02006
Nonconforming Material (Internal Procedure CNST01009)		Main/ Service	Electronic / Failure Based	Nonconforming Material Database (Material Testing Lab Sharepoint Site)	NY LI Upstate MA RI	Operations / Construction / Material Testing Lab / DIMP/ Codes and Standards	Nonconforming material removed should be reported to the Material Testing Lab.

14.0 APPENDICES FOR RHODE ISLAND

RHODE ISLAND
APPENDIX A
KNOWLEDGE OF FACILITIES

Table A-1: Reportable Gas Incidents by Year

Year	Number of Incidents	Fatalities	Injuries	Property Damage
2021	0	0	0	-
2020	0	0	0	-
2019	0	0	0	-
2018	0	0	0	-
2017	3	0	0	$403,895
2016	0	0	0	-
2015	1	0	0	$58,140
2014	0	0	0	-
2013	1	0	0	$29,184
2012	1	0	0	$133,377
2011	0	0	0	-
2010	0	0	0	-
2009	1	0	2	$100,000
2008	0	0	0	-
2007	0	0	0	-
2006	0	0	0	-
2005	0	0	0	-
2004	2	0	2	$118,000
2003	1	0	0	$100,000
2002	0	0	0	-
2001	0	0	0	-
2000	2	0	0	$250,000
1999	0	0	0	-
1998	0	0	0	-
1997	0	0	0	-
1996	1	0	0	$250,000
1995	0	0	0	-
1994	1	0	1	$100,000
1993	1	0	0	$300,000
1992	2	0	1	$142,500
Total	**17**	**0**	**6**	**$1,985,096**

Table A-2: Reportable Gas Incidents by Cause

Year	Corrosion	Natural Forces	Excavation Damage	Outside Force	Material or Weld Failure	Equipment Failure	Incorrect Operation	Other
2021	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0
2017	0	0	1	1	0	0	0	1
2016	0	0	0	0	0	0	0	0
2015	0	1	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2013	0	0	1	0	0	0	0	0
2012	0	0	0	1	0	0	0	0
2011	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2009	0	0	0	1	0	0	0	0
2008	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2004	0	2	0	0	0	0	0	0
2003	0	1	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	2
1999	0	0	0	0	0	0	0	0
1998	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0
1996	0	0	1	0	0	0	0	0
1995	0	0	0	0	0	0	0	0
1994	1	0	0	0	0	0	0	0
1993	0	0	1	0	0	0	0	0
1992	0	1	1	0	0	0	0	0
30-Year Total	**1**	**5**	**5**	**3**	**0**	**0**	**0**	**3**

Table A-3: 10-Year Incident History Details (**Rhode Island**)

Company	Year	Facility	Asset Class/Subclass	Street	Town	Leak Cause
NIMO (RI)	2017	MAIN	Steel - 3"	Intersection Baker St and Water St	WARREN	Excavation Damage
Details:	The contractor while installing the water main hit a 3 inch gas main with a backhoe. During pipe repair process 310 customers were shut off and were all restored successfully after repair.					
NIMO (RI)	2017	SERVICE RISER	Plastic (PE) - 5/8"	110 Toll Gate Road	WARWICK	Other outside force damage
Details:	Vehicle driver crashed into a service riser and (3) meter assembly, causing the gas leak. This caused fire and one person was hospitalized. A 5/8" pe plastic end cap was installed and tested.					
NIMO (RI)	2017	MAIN	Steel - 12" - LP	30 Allens Avenue	Providence	Other Incident Cause
Details:	There was insufficient support of a live gas as the earth was removed during construction allowing vibration and pressure to pull the one 12 inch 99 psig pipe segments out from a 12inch dresser coupling					
NIMO (RI)	2015	MAIN	CI -6"- LP	130 Woodbury Street	Providence	Natural Force
Details:	Pipe in frozen ground caused disturbance and odor in area					
NIMO (RI)	2013	MAIN	Protected Coated Steel – 8" – HP(35#)	Rocky Hill Road & Rte-116	Lincoln	Excavation
Details:	Mechanical puncture on gas main by excavator					
NIMO (RI)	2012	I&R	Valve	Purgatory Road	Middletown	Other Outside Force
Details:	Vandalism, Contractor working for St. George's School hit an underground gas main, forcefully entered into NG's District Regulator building & closed a valve which caused 483 service outage.					

RHODE ISLAND
APPENDIX B
THREAT IDENTIFICATION

In April thru June of 2021, groups of Subject Matter Experts (SMEs) were brought together, each having knowledge of threats in the various communities served by National Grid. Details on SME qualifications as well as copies of their interview records are located in the Distribution Integrity Management Program files. A summary of the threats identified are presented below in Table 14-1 and Table 14-2.

Table 14-1: Summary of Applicable Threats

SME's to Consider the Following	YES / NO
Do you have the necessary knowledge and/or experience (skills sets) regarding the areas of expertise for which you provided knowledge or supplemental information for input into the DIMP plan? (PHMSA Q.)	Yes
Do operator personnel in the field understand their responsibilities under DIMP plan? (PHMSA Q.)	Yes
Have you received DIMP training? (PHMSA Q.)	Yes
Have you received instructions to address the discovery of pipe or components not documented in the company records? (PHMSA Q.)	Yes
Have you received instructions to address, if you find any possible issue? (ex: corrosion, dented pipe, poor fusion joints, missing coating, excavation damage, mechanical fitting failures). (PHMSA Q.)	Yes
Have you received instructions to address when you find situations where the facilities examined (e.g., Material, Diameter, Coating, etc.) are different than records indicate, what documentation do you prepare? (PHMSA Q.) • If yes, are the findings documented?	Yes
During any repairs, if you find an improperly installed fitting, do you remediate it? (PHMSA Q.) • If yes, are the findings documented?	Yes
1. Does CMS conduct atmospheric corrosion inspection when they have access to facilities? • If yes, are the findings documented?	Yes
2. Do you know the procedures to visually examine any plastic fusion that is uncovered as part of excavation? • If yes, are the findings documented?	Yes
3. Do you notify damage prevention if any municipal work is being performed near gas distribution facilities? • If yes, are the findings documented?	Yes
4. Does Cross Bore recognized as risk? • If yes, are the findings documented?	Yes

Primary Threat Category	SME's to Consider the Following	Rhode Island
Corrosion	Is there known evidence of Corrosion on the system?	Yes
	Is there a known history of leakage on the system due to Corrosion?	Yes
	Threat Applicable?	Yes
Natural Force	Is there known evidence of damage or failures on the system due to natural forces?	Yes
	Is there a known history of leakage on the system due to Natural forces?	Yes
	Threat Applicable?	Yes
Excavation Damage	Is there known evidence of damage or failures on the system due to Excavation Damage?	Yes
	Is there a known history of leakage on the system due to Excavation Damage?	Yes
	Threat Applicable?	Yes
Other Outside Forces	Is there known evidence of damage or failures on the system due to Other Outside Forces?	Yes
	Is there a known history of leakage on the system due to Other Outside Forces?	Yes
	Threat Applicable?	Yes
Material or Weld Failure	Is there known evidence of damage or failures on the system due to Material or Weld Failure?	Yes
	Is there a known history of leakage on the system due to Material or Weld Failure?	Yes
	Threat Applicable?	Yes
Equipment Failure	Is there known evidence of damage or failures on the system due to Equipment Failure?	Yes
	Is there a known history of leakage on the system due to Equipment Failure?	Yes
	Threat Applicable?	Yes
Incorrect Operations	Is there known evidence of damage or failures on the system due to Incorrect Operations?	Yes
	Is there a known history of leakage on the system due to Incorrect Operations?	Yes
	Threat Applicable?	Yes
Others	Is there known evidence of damage or failures on the system due to others reasons?	Yes
	Is there a known history of leakage on the system due to other reasons?	Yes
	Threat Applicable?	Yes

Table 14-2: Summary of SME Interview Responses for Threat Identification

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
Corrosion	Cast Iron Pipe	Does Cast Iron pipe exist in the system?	**Yes**
		Is there a known history of body-of-pipe leaks, fractures, or graphitization?	**Yes**
	Bare Steel or Wrought Iron Pipe (with no CP other than Localized hot spotting with anodes)	Do bare (uncoated) steel main or services exist in the system that are not under CP?	**Yes**
		Is there known evidence of external corrosion on bare steel or wrought iron pipes not under CP?	**Yes**
		Is there a history of leakage on bare steel or wrought iron pipes not under CP?	**Yes**
	Bare Steel or Wrought Iron Pipe (with CP other than just localized hot spotting with anodes)	Do bare (uncoated) steel main or services exist in the system that are under CP?	**No**
		Is there known evidence of external corrosion on bare steel pipes under CP?	**No**
		Is there a known history of leakage on bare steel pipes under CP?	**No**
	Coated Steel with CP	Is there known evidence of external corrosion on coated steel pipe with CP?	**Yes**
		Is there a known history of leakage on coated steel pipe with CP?	**Yes**
		Are some CP systems frequently down (not achieving the required level of protection); more than 10% of the time?	**Yes**
		Is there a risk of grounds installed on risers making CP ineffective?	**Yes**
	Coated Steel w/o CP	Is there known evidence of external corrosion on coated steel pipe without CP?	**Yes**
		Is there a known history of leakage on coated steel pipe without CP?	**Yes**
	Copper Services	Are direct buried or inserted copper services known to exist in the system?	**Yes**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
		Is there a known history of leakage on copper services?	**Yes**
	Stray Current	Do distribution facilities exist near DC transit systems, high voltage DC transmission systems or other known sources of DC current?	**Yes**
		Are any facilities known to be impacted by sources of stray DC current that has or may result in corrosion?	**Yes**
	Internal Corrosion	Are liquids known to exist within any portions of the distribution system?	**Yes**
		Is there known evidence of internal corrosion on steel pipe?	**Yes**
		Is there a known history of leakage caused by internal corrosion of steel pipe?	**Yes**
	Atmospheric Corrosion on above ground facilities	Do above ground distribution facilities exist in areas exposed to marine atmosphere, high humidity, atmospheric pollutants or agricultural chemicals?	**Yes**
		Is there known evidence of external atmospheric corrosion on exposed steel pipe, equipment or fittings?	**Yes**
		Is there a known history of leakage caused by atmospheric corrosion of steel pipe?	**Yes**
	Atmospheric Corrosion of facilities in Vaulted areas underground	Do gas distribution facilities exist underground in vaulted areas?	**Yes**
		Is there known evidence of external atmospheric corrosion on exposed steel pipe, equipment or fittings?	**Yes**
		Is there a known history of leakage caused by atmospheric corrosion of steel pipe in vaults?	**Yes**
	Corrosion of carrier pipe in Cased Crossing	Do steel carrier pipes exist within cased crossings?	**Yes**
		Are there any existing known contacts between carrier pipes and casings?	**Yes**
		Is there known evidence of past or active external corrosion on cased steel pipe?	**Yes**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
		Is there a known history of leakage caused by corrosion on cased steel pipe?	**Yes**
	Other Corrosion	Are there other corrosion threats?	**Wall Piece, at Dis-Similar Metals & Isolated Fittings**
Natural Forces	Seismic Activity	Are there any seismically active zones or fault lines that exist in the area?	**Yes**
		Is there a history of leakage associated with Seismic activity?	**No**
	Earth Movement / Landslide (Unstable Soil)	Are there any areas susceptible to earth movement or landslide in the area?	**Yes**
		Is there a known history of leakage associated with landslide or earth movement?	**No**
	Frost Heave	Are there any areas susceptible to frost heave that exist in the area?	**Yes**
		Is there a known history of leakage resulting from frost heave?	**Yes**
	Flooding	Are there any areas within the gas system that are subject to flooding?	**Yes**
		Is there a known history of leakage or damage associated with flooding?	**Yes**
	Over-pressure due to snow/ice blockage	Are pressure control equipment vents subject to ice blockage during the winter?	**Yes**
		Is there a known history of over-pressure events as a result of snow/ice blockage?	**Yes**
	Tree Roots	Is there a known history of leakage to pipe or fittings as a result of tree root damage?	**Yes**
	Other Natural Forces	Is there a known history of leakage or damage due to other natural force causes; including but not limited to lightning, wild fire or high winds (tornados)?	**Lightning**
Excavation Damage	Improper Excavation Practice	Has damage requiring repair or replacement occurred on properly marked facilities due to the failure of the excavator to follow proper excavation rules and procedures?	**Yes**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
	Facility not located or marked	Has damage requiring repair or replacement occurred due to failure to locate a valid and timely locate request?	**Yes**
	One-Call Notification Practices Not Sufficient	Has damage requiring repair or replacement occurred due to an error made at the one-call notification center?	**Yes**
	Mis-Marked Facilities	Has damage requiring repair or replacement occurred due to the mis-marking of facilities?	**Yes**
		Threat Applicable?	**Yes**
	Incorrect Facility Records	Has damage requiring repair or replacement occurred due incorrect facility records?	**Yes**
	Other Excavation Damage	Has damage requiring repair or replacement occurred due other causes?	**Shallow Mains and Plastic w/o Tracer Wire**
Other Outside Force Damage	Vehicle Damage to Riser/Meter	Are existing risers and/or meters exposed to damage from vehicular damage that do not have barriers or other protection conforming to current design requirements?	**Yes**
		Has known leakage occurred due to vehicle damage to risers/meters.	**Yes**
	Vandalism	Are gas valves susceptible to damage by vandalism that has the potential to pose a risk to employees or the public?	**Yes**
		Has leakage or other unsafe condition been created by vandalism?	**Yes**
	Structure Fire	Is there a history of damage to gas meters or other equipment due to structure fires?	**Yes**
	Other Outside Force Damage	Has damage requiring repair or replacement occurred due other outside forces?	**Falling ice, Heat, ground contamination, down electric lines**
Pipe, Weld or Joint Failure	Century Products (MDPE 2306)	Is Century Products (MDPE 2306) pipe (Tan) known to exist in the system?	**No**
		Is there a history of leakage of Century Products (MDPE 2306) pipe due to material failure?	**No**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
	Aldyl A (MDPE 2306/2406)	Is pre-1973 Aldyl A pipe (Tan, but can turn grey) known to exist in the system?	**Yes**
		Has pre-1973 Aldyl A pipe been known to leak due to brittle-like failure from rock impingement or other stresses?	**Yes**
		Is there a history of leakage of pre-1973 Aldyl A pipe due to material failure?	**Yes**
		Is 1973 and later Aldyl A pipe (Tan, but can turn grey) known to exist in the system?	**Yes**
		Has 1973 and later Aldyl A pipe been known to leak due to brittle-like failure from rock impingement or other stresses?	**Yes**
		Is there a history of leakage of 1973 and later Aldyl A pipe due to material failure?	**Yes**
	Aldyl AAAA (MDPE 2306) Green Aldyl	Is Green Aldyl pipe known to exist in the system?	**No**
		Is there a history of brittle like failures of Green Aldyl pipe?	**No**
		Is there a history of leakage of Green Aldyl pipe due to material failure?	**No**
	PVC – Polyvinyl Chloride	Is PVC pipe known to exist in the system?	**No**
		Is there a history of leakage of PVC pipe due to material failure?	**No**
	CAB – Cellulose Acetate Butyrate	Is CAB pipe known to exist in the system?	**No**
		Is there a history of leakage of CAB pipe due to material failure?	**No**
	PB – Polybutylene	Is PB pipe known to exist in the system?	**Yes**
		Is there a history of leakage of PB pipe due to material failure?	**Yes**
	PP – Polypropylene	Is PP pipe known to exist in the system?	**No**
		Is there a history of leakage of PP pipe due to material failure?	**No**
	Polyamide - PA	Is PA pipe known to exist in the distribution system?	**No**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
		Is there a history of leakage of PA pipe due to material failure?	**No**
	PE Fusion failure	Is there a history of PE Fusion Failures or leakage in the system?	**Yes**
		Are any types of PE fusion (type, material, size, age, process, geographic area) more prone to leakage or failure?	**Yes**
	Pre-1940 Oxy-Acetylene Girth Weld	Do pre-1940 Oxy-Acetylene Girth Welds exist on pipe greater than 4 inch?	**Yes**
		Is there a history of pre-1940 Oxy-Acetylene Girth Weld failures or leakage in the system due to material failure?	**Yes**
	Other	Do other material failures occur that present a possible current or future risk?	**Yes**
Equipment Failure	Mechanical Fittings	Is there a history of Mechanical Fitting failures or leakage in the system due to pullout?	**No**
		Is there a history of Mechanical Fitting failures or leakage in the system due to seal leakage?	**Yes**
		What Types and Manufactures of Stab Type Mechanical Fittings have you seen used in the System?	**Perfection, Permaset, Plexco, Dresser, AMP, Continental, LYCO, Kerotest**
		Are any types of Mechanical Fitting (type, material, size, age, manufacturer, geographic area) more prone to leakage or failure?	**LYCO, Kerotest**
	Valves	Are valves inoperable, inaccessible and or paved over without timely identification and repairs?	**Yes**
		Are certain types or makes of valves more likely to leak?	**Kerotest**
	Service Regulators	Is there a history of service regulator failures that present a threat to the public or employees?	**Yes**
		Are certain types or makes of service regulator more likely to create a risk?	**Mercury**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
	Meters	Is there a history of meter failures that present a threat to the public or employees?	**No**
		Are certain types or makes of meters more likely to create a risk?	**No**
	Other Equipment Failure	Is there a history of other equipment failures that present a threat to the public or employees?	**No**
		Are certain types or makes of other equipment more likely to create a risk?	**No**
Incorrect Operations	General	Have inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error resulted in an incident that created a risk to the gas distribution system?	**Yes**
	Gas lines bored through Sewers	Have pipes been installed via unguided or guided bore without proper procedures to ensure other facilities are not damaged?	**Yes**
		Have pipes unknowingly bored through sewer lines been damaged by sewer line cleaning operations?	**Yes**
Other	Bell Joint Leakage	Does Cast Iron pipe exist in the system?	**Yes**
		Is there a history of bell joint leaks?	**Yes**
		Are certain diameters or parts of the system known to be more prone to bell joint failure or leakage than others?	**Yes**
	Inserted Copper Puncture	Do copper services inserted in steel exist in the system?	**Yes**
		Is there a history of leakage of copper services due to puncture by a deteriorated steel outer casing?	**No**
	Copper Sulfide	Have any safety incidents occurred as a result of copper sulfide in copper services or service regulators?	**No**
	Construction over gas mains & services	Have others constructed over gas facilities or taken other action that prevents effective leak survey and other maintenance?	**Yes**
		When identified, is construction that impacts required maintenance corrected in a timely manner?	**Yes**

Primary Threat Category	Material or Sub-Threat	SME's to Consider the Following	Rhode Island
	Other	Are there any other known threats to the Gas Distribution system that we need to be aware of?	**Gas mains in Catch basins, Vibration equipment, Anaerobic sealants**

RHODE ISLAND
APPENDIX C
EVALUATION AND RANKING OF RISK

HIGHEST RANKED RISKS

STATE: RHODE ISLAND
REGION: ALL
FACILITY: MAINS

Mitigation Will Be As Per Appendix D, Except As Otherwise Indicated In Notes

Material	Pressure	Diameter	Mileage	Risk Score	Threat Category	Known Incident	Additional Mitigation Notes
Cast Iron	LP	4" Thru 8"	520.51	1.71	NATURAL FORCE	**Known Incident** Yr 2015 - Pipe in frozen ground	Yr 2015 - Pipe in frozen ground
ProtectedCoated Steel	HP	Upto 4"	208.99	1.04	EXCAVATION	**Known Incident** Yr 2017 -Damage by contractor.	Yr 2017 -Damage by contractor.
ProtectedCoated Steel	HP	Over 4" Thru 8"	105.37	1.04	EXCAVATION	**Known Incident** Yr 2013 - Mechanical puncture on gas	Yr 2013 - Mechanical puncture on gas
UnprotectedBare Steel	> 60 PSI,Not T	Over 4" Thru 8"	0.7	3.50	CORROSION/ MATERIAL/WELD / NATURAL FORCE/ EXCAVATION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	> 60 PSI,Not T	Over 8"	1.9	3.50	CORROSION/ MATERIAL/WELD		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	> 60 PSI,Not T	Upto 4"	1.0	3.50	CORROSION/MATERIAL/WELD /EXCAVATION/NATURAL FORCE		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	HP	Over 8"	4	2.77	CORROSION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	HP	Upto 4"	74.36	2.77	CORROSION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	HP	Over 4" Thru 8"	18.4	2.77	CORROSION		The replacement strategy will be based on the failure analysis and SME Input
Cast Iron	HP	Under 4"	0.1	2.52	OTHER		The replacement strategy will be based on the failure analysis and SME Input
Cast Iron	HP	4" Thru 8"	2.8	2.52	OTHER/ NATURAL FORCE		The replacement strategy will be based on the failure analysis and SME Input

RHODE ISLAND - MAINS (Cont.)

Material	Pressure	Diameter	Mileage	Risk Score	Threat Category	Known Incident	Additional Mitigation Notes
Cast Iron	HP	Over 8"	16.4	2.52	OTHER		The replacement strategy will be based on the failure analysis and SME Input
Plastic	> 60 PSI,Not T	Upto 4"	98.2	2.35	EXCAVATION/ O. O. FORCE/ MATERIAL/WELD		The replacement strategy will be based on the lab results of failures
Plastic	> 60 PSI,Not T	Over 4" Thru 8"	33.7	2.35	EXCAVATION/ O. O. FORCE/ MATERIAL/WELD		The replacement strategy will be based on the lab results of failures
Plastic	> 60 PSI,Not T	Over 8"	3.14	2.35	EXCAVATION/O. O. FORCE /MATERIAL/WELD		The replacement strategy will be based on the lab results of failures
UnprotectedCoated Steel	> 60 PSI,Not T	Upto 4"	1.65	2.09	MATERIAL/WELD / CORROSION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedCoated Steel	> 60 PSI,Not T	Over 8"	4.23	2.09	MATERIAL/WELD / CORROSION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedCoated Steel	> 60 PSI,Not T	Over 4" Thru 8"	1.23	2.09	MATERIAL/WELD / CORROSION		The replacement strategy will be based on the failure analysis and SME Input
Ductile Iron	HP	Over 4" Thru 8"	0.68	1.98	NATURAL FORCE/ CORROSION		The replacement strategy will be based on the failure analysis and SME Input
Cast Iron	LP	Under 4"	4.88	1.95	NATURAL FORCE		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	LP	Upto 4"	23.52	1.94	CORROSION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	LP	Over 4" Thru 8"	31.46	1.94	CORROSION		The replacement strategy will be based on the failure analysis and SME Input
UnprotectedBare Steel	LP	Over 8"	3.20	1.94	CORROSION		The replacement strategy will be based on the failure analysis and SME Input
Ductile Iron	LP	Over 4" Thru 8"	6.50	1.49	NATURAL FORCE		The replacement strategy will be based on the failure analysis and SME Input
ProtectedCoated Steel	HP	Over 8"	26.85	1.04	EXCAVATION		

Note: *The above table shows combined threats for each asset. Refer to Appendix A – Table A-3 (10-Year Incident History Details) for a complete list of threats.*

HIGHEST RANKED RISKS

STATE: RHODE ISLAND
REGION: ALL
FACILITY: SERVICE (Active & Inactive)

Mitigation Will Be As Per Appendix D, Except As Otherwise Indicated In Notes

Material	Pressure	Meter Set	Quantity	Risk Score	Threat Category	Known Incident (2021 to 2011)	Additional Mitigation Notes
Plastic	LP	Outside	23,936	1.77	O. O. FORCE	**Known Incident** Yr 2017 - Vehicle Crash into Riser	Service Performances are included in the Main Replacement Prioritization.
Protected Coated Steel	LP	Outside	671	0.97	O. O. FORCE	Known Incident Yr 2009 - Vehicular Damage	Service Performances are included in the Main Replacement Prioritization.
Cast Iron	LP	Inside	15	17.29	EXCAVATION/ CORROSION/ NATURAL FORCE/O. O. FORCE		Service Performances are included in the Main Replacement Prioritization.
Cast Iron	LP	Outside	10	17.29	EXCAVATION/ CORROSION/ NATURAL FORCE		Service Performances are included in the Main Replacement Prioritization.
Unprotected Bare Steel	HP	Inside	908	4.82	CORROSION		Service Performances are included in the Main Replacement Prioritization.
Unprotected Bare Steel	HP	Outside	2,067	3.86	CORROSION		Service Performances are included in the Main Replacement Prioritization.
Unprotected Bare Steel	LP	Outside	3,458	3.16	CORROSION		Service Performances are included in the Main Replacement Prioritization.
Unprotected Coated Steel	HP	Inside	1,435	3.00	CORROSION		Service Performances are included in the Main Replacement Prioritization.
Plastic	HP	Inside	18,593	2.93	EXCAVATION/O. O. FORCE		Service Performances are included in the Main Replacement Prioritization.
Unprotected Coated Steel	LP	Inside	1,284	2.75	CORROSION		Service Performances are included in the Main Replacement Prioritization.
Plastic	LP	Inside	26,366	2.74	EXCAVATION/ O. O. FORCE		Service Performances are included in the Main Replacement Prioritization.

RHODE ISLAND – SERVICE (Cont.)

Material	Pressure	Meter Set	Quantity	Risk Score	Threat Category	Known Incident (2021 to 2011)	Additional Mitigation Notes
Copper	HP	Inside	45	2.48	EQ. FAILURE/ EXCAVATION/ CORROSION/ OTHER		Service Performances are included in the Main Replacement Prioritization.
Unprotected Coated Steel	HP	Outside	2,642	2.40	CORROSION		Service Performances are included in the Main Replacement Prioritization.
Plastic	HP	Outside	73,944	2.36	EXCAVATION		Service Performances are included in the Main Replacement Prioritization.
Copper	LP	Inside	5	2.13	EQ. FAILURE/ EXCAVATION/ CORROSION/ OTHER		Service Performances are included in the Main Replacement Prioritization.
Copper	HP	Outside	20	1.98	EQ. FAILURE/ EXCAVATION/ CORROSION/ OTHER		Service Performances are included in the Main Replacement Prioritization.
Copper	LP	Outside	1	1.57	EQ. FAILURE/ EXCAVATION/ CORROSION/ OTHER		Service Performances are included in the Main Replacement Prioritization.

Note: *The above table shows combined threats for each asset. Refer to Appendix A – Table A-3 (10-Year Incident History Details) for a complete list of threats.*

RHODE ISLAND
APPENDIX D
IDENTIFICATION AND IMPLEMENTATION OF MEASURES TO ADDRESS RISKS

Table 14-3: Threat Mitigation

Primary Threat Category	Sub-Threat	Existing Mitigation or Additional/Accelerated Actions Rhode Island
Corrosion	Cast Iron Pipe Graphitization (including risk of crack or break due to becoming brittle)	Periodic Leak Surveys, Proactive/Reactive Leak Prone Pipe Replacement Program, and Leak Management Programs
	Bare Steel or Wrought Iron Pipe	Periodic Leak Surveys, Proactive/Reactive Leak Prone Pipe Replacement Program, and Leak Management Programs
	Coated Steel w/ CP	Cathodic Protection Monitoring, Periodic Leak Survey, Reactive Pipe Replacement, and Leak Management Program
	Grounds installed on risers making CP ineffective	Cathodic Protection Monitoring
	Coated Steel w/o CP	Periodic Leak Surveys, Proactive/Reactive Leak Prone Pipe Replacement Program, and Leak Management Programs
	Copper Services	Proactive Service Replacement, Periodic Leak Surveys, Service Tees Replaced w/ Main Replacements and Leak Management Programs
	Stray Current	Design, Periodic Leak Surveys, Proactive Corrosion Control Inspections
	Internal Corrosion	Periodic Leak Surveys, Proactive/Reactive Pipe Replacement, and Leak Management Programs
	Atmospheric Corrosion on above ground facilities	Coating and Periodic Leak Surveys/Atmospheric Corrosion Inspections

Primary Threat Category	Sub-Threat	Existing Mitigation or Additional/Accelerated Actions Rhode Island
	Atmospheric Corrosion of facilities in Vaulted areas underground	Coating and Periodic Leak Surveys/Atmospheric Corrosion Inspections
	Corrosion of carrier pipe in Cased Crossing	Design and Cathodic Protection Monitoring
	Corrosion of Buried Farm Tap Equipment	Not Applicable
	Wall Piece at Dis-Similar Metals & Isolated Fittings	Periodic Leak Surveys, and Leak Management Programs
	Corrosion of Service Fittings on cast iron mains that are not cathodically protected.	Periodic Leak Surveys, Services Associated with Main Replacement Programs are Replaced, and Leak Management Program.
Natural Forces	Seismic Activity	Proactive Leak Survey Programs
	Earth Movement / Landslide(Unstable Soil)	Proactive Leak Survey Programs
	Frost Heave	Periodic Leak Survey Programs / Winter Operations
	Flooding	Proactive Leak Survey Programs
	Over-pressure due to snow/ice blockage or freeze up.	Design, Periodic Leak Survey, and Customer Communications
	Tree Roots	Periodic Leak Survey Programs

Primary Threat Category	Sub-Threat	Existing Mitigation or Additional/Accelerated Actions Rhode Island
	Other Natural Forces	Design, Periodic Leak Survey
Excavation Damage	Improper Excavation Practice (including mitigation for high-risk tickets)	Damage Prevention Monitoring, Design, EFV's, training and emergency response
	Facility not located or marked	Damage Prevention Monitoring, Design, EFV's, training and emergency response
	One-call notification practices not sufficient	Damage Prevention Monitoring, Design, EFV's, training and emergency response
	Mis-Marked Facilities	Damage Prevention Monitoring, Design, EFV's, training and emergency response
	Incorrect Facility Records	EFV's and Field Corrections
	Shallow Mains - reduced cover	Design, Training, and Map Notation.
	Plastic without tracer wire that cannot be located	EFV's, training, and service records.
Other Outside Force Damage	Vehicle Damage to Riser/Meter	Design (Bollards/Meter Protection Posts)
	Vandalism	Design, EFV's Periodic Leak Survey Programs
	Structure Fire	Design, EFV's, training and emergency response
	Falling Ice, Heat Ground Contamination, Down Electric Lines	Customer Communications for Snow/Falling Ice
Pipe, Weld or Joint Failure	Pre-1973 Aldyl A (Tan MDPE 2306/2406)	Periodic Leak Survey and Proactive/Reactive Main Replacements.

Primary Threat Category	Sub-Threat	Existing Mitigation or Additional/Accelerated Actions Rhode Island
	1973 and later Aldyl A (Tan MDPE 2306/2406)	Periodic Leak Survey and Proactive/Reactive Main Replacements.
	Aldyl 4A (Green MDPE 2306)	Not Applicable.
	PE other than Aldyl A & 4A	Periodic Leak Survey and Proactive/Reactive Main Replacements.
	PE Fusion failure	Periodic Leak Survey & Training
	Pre-1940 Oxy-Acetylene Girth Weld	Periodic Leak Survey
	Other Failures	Periodic Leak Survey
Equipment Failure	Mechanical Fittings	Periodic Leak Survey
	Valves	Periodic Leak Survey
	Service Regulators	Initiating Service Regulator Inspections.
	Meters (including Tin Meters)	Periodic Leak Survey, Meter Relocations, and Odorization.
Incorrect Operations	General	Operator Qualifications, training and emergency response
	Gas lines bored through Sewers	Operator Qualifications, training and emergency response
Other	Bell Joint Leakage, Cast Iron and Ductile Iron	Periodic Leak Survey.
	Inserted Copper Puncture	Periodic Leak Survey and Main Replacements

Primary Threat Category	Sub-Threat	Existing Mitigation or Additional/Accelerated Actions Rhode Island
	Copper Sulfide	Periodic Leak Survey and Main Replacements
	Construction over gas mains & services	Operator Qualifications, training and emergency response
	Catch Basins, Vibration Equipment, Anaerobic Sealants	Periodic Leak Surveys

Extensive investigation/research, monitoring and improvement works are being performed on some special projects listed below and all the reports are incorporated by reference in its most updated form.

MITIGATION OF OIL/LIQUIDS

Natural gas pipeline liquids have been identified as recurring at some existing distribution collection points as well as some commercial customer locations within a portion of the natural gas distribution system. These liquids can be a problem in and of themselves, but they can also cause trace contaminants such as PCBS to become mobile and accumulate at different points, possibly even travelling all the way to a customer's meter set. National Grid is actively monitoring collection points, removing liquids from the system and employing mitigation measures to help limit movement of liquids and ensure customer protection.

ATMOSPHERIC CORROSION

In Rhode Island, National Grid visits all services with inside meter sets to inspect the service for atmospheric corrosion. Due to the timing of these inspections, National Grid cannot always gain access to all buildings to inspect the pipe. National Grid attempts two more times to contact the customer and schedule an appointment. However, a large number of service inspections attempted are never completed and have a result of "Can't Get In" (CGI).

In order to address any safety concerns with these services, National Grid conducted a review to see if any other inspection programs or service work were conducted at the address in the last 6 years. National Grid determined that if the service was replaced in the last 6 years or if an atmospheric corrosion inspection was completed as a "tag-a-long" inspection to other work being completed, the service was at a lower risk to be severely corroded.

For the remaining services that have had no access to the premises in the last 6 years, National Grid prioritized the risk by year of installation and will begin to turn the customer's gas off in the summer in order to schedule an appointment for an atmospheric corrosion inspection.

INSIDE METER SETS

The National Grid Inside Meter Sets program is dedicated to upgrading the natural gas infrastructure by relocating inside gas meter set. Natural gas meters are moved from inside to outside locations so that National Grid can continue to provide safe, high-quality customer service by replacing older leak prone pipe made of cast iron or unprotected steel. Service lines may also be replaced with modern materials if they have not previously been replaced during routine maintenance. Some of the benefits of this program are the replacement of LPP with more modern materials in order to reduce the risk of gas leaks. This program also contributes to customer and company convenience by eliminating the need to enter the home for atmospheric corrosion inspections and leak surveys. The inside meter sets program increases customer satisfaction by facilitating more frequent and comprehensive inspections and maintenance work on meters and service piping that has been placed outside. Lastly, the inside meter sets relocation program eliminates the risk of shut-off due to access issues, and provides easy access to relocated outside meters in the event of an emergency.

INNERTITE FITTINGS

National Grid had 2 incidents involving Inner-Tite fittings in 2008 and 2011 on Long Island, with the 2008 incident resulting in property damage. History has shown the Inner--Tite fitting has corroded at a faster rate than the rest of the service. Because of this, National Grid has identified all plastic and plastic tube inside meter services installed in 1974 and prior for the Rhode Island Service territory to be inspected, as services meeting these conditions involve the possibility of having the Inne-Tite equipment installed as part of the fitting assembly.

From 2012 – 2014, National Grid visited every site and has completed all inspections on plastic and plastic tube inside meter services installed pre-1975. The Company will continue to monitor these types of fittings through the Atmospheric Corrosion.

WATER INTRUSION/WASHOUT PROJECTS

The National Grid Water Intrusion/Washouts Program is in place to remediate situations where water has infiltrated the gas distribution system. This situation is known to cause poor pressure, resulting in repeated customer supply disruptions and decreased system reliability. The program addresses outstanding water intrusion issues in addition to allowing in-year projects to be walked-in as locations meeting criteria for inclusion in the program are identified. This program also addresses unanticipated infrastructure washouts and main exposures that can occur due to storms, heavy rains and/or seasonal snow melt. Main exposure/undermining can result in damage to facilities, emergency response and potential loss of service to customers. Distribution washouts/exposures can create potential for further damages and risks to assets if not addresses efficiently and appropriately. National Grid is required to ensure proper integrity for safe operation of its assets and to maintain proper cover and protection of its facilities.

PROACTIVE MAIN REPLACEMENT PROGRAM – LPP

This program supports the replacement of Leak Prone Pipe (LPP) inventory, defined as mains less than 16" in diameter that are non-cathodically protected steel, whether bare or coated (collectively termed "unprotected steel") or cast/ wrought iron or pre 1985 Aldyl-A plastic. The goal of this program is to reduce the risk associated with leak prone pipe in the distribution system.

CI FROST PATROL

Cast Iron (CI) is a brittle material and has the tendency to break when extended periods of cold temperature allow frost to form in the ground. The downward pressure of the expanding frost line can exert such great force that it can crack smaller diameter cast iron mains. In a natural process of graphitization, iron degrades to softer elements, making iron pipelines more susceptible to cracking. Gas may leak from the joints or through cracks in the pipe if graphitization has occurred. National Grid actively performs proactive periodic surveys in the Winter specifically to identify CI breaks and joint leaks at cycles not to exceed 20 calendar days unless extenuating circumstances exist. Additionally, Type 2A and 2 leaks are also scheduled for surveillances at accelerated frequencies as well in order to address the threat of underground migration.

PLASTIC FAILURES

National Grid policy requires that failed plastic parts (either leaking or visually identified as not exhibiting properties of a properly fused or assembled part) be returned to the Laboratory for analysis and testing. When possible, parts are destructively tested to assess cause of leak/failure. A log of analyzed failures is maintained and periodically reviewed in order to recognize system wide failure trends. Local analysis (frequently a leak survey) is conducted to check contemporary and contiguous installation work for similar failures. The paperwork associated with nearby failures from other years may also be examined in order to further complete the review. Certain failures, such as the identification of slow crack growth on pre-1985 Aldyl-A plastic, may lead to proactive replacement of similar pipe.

CROSS BORE

National Grid has installed several plastic gas mains through Horizontal Directional Drilling (HDD) technology where the pipe can bore through an unverified sewer lateral and cause blockage. If a mechanical cleaning tool is used to remove the blockage, it may lead to damaging the gas line, causing the gas to migrate into the building that can lead to an explosion. National Grid cross bore inspection program address all previous HDD installations to review if a cross bore incident has occurred and if so, take proactive steps to remediate the situation.

PROACTIVE SERVICE REPLACEMENT

RI proactive service replacement program is a program that targets the replacement of copper and unprotected steel services. The services are prioritized for replacement based on leak history statistics and those with inside meter sets. All targeted services should be outside the bounds of planned main replacements.

ACCESS PROTECTION

The Access Protection program was implemented due to an Incident in the UK, where kids climbed on an elevated pipe resulting in a fatality. National Grid installs protection on any elevated structure. The program is to reduce the risk of public injury by restricting or deterring public access to the Company's elevated gas facilities. In accordance with the customer/community-first approach, the Company has installed protective barriers, such as fencing or other physical deterrents, that will restrict or deter the public from accessing or climbing on elevated gas mains.

PIPE ON BRIDGES

National Grid developed the program to replace or rehabilitated gas pipe and appurtenances on aboveground structures, typically bridges, due to integrity concerns.

RHODE ISLAND
APPENDIX E
MEASUREMENT OF PERFORMANCE, MONITORING RESULTS, AND EVALUATION EFFECTIVENESS

Appendix E, Section 1 – Number of Hazardous Leaks Either Eliminated or Repaired, Categorized by Cause

The 5 years baseline and ongoing performance of the number of Hazardous (***Type 1***) Leaks for Main and Service combined Either Eliminated or Repaired, Categorized by Cause is provided below (Including Excavation Damage Leaks):

INCLUDING Damage

Rhode Island

Cause		2016	2017	2018	2019	2020	2021
Corrosion	Actual	292	368	251	266	177	270
	Baseline	Rolling average since 2016 + 0.5 standard deviation (305 for 2016 - 2021)					
Natural Forces	Actual	33	26	93	53	13	23
	Baseline	Rolling average since 2016 + 0.5 standard deviation (59 for 2016 - 2021)					
Excavation Damage	Actual	106	116	97	95	75	105
	Baseline	Rolling average since 2016 + 0.5 standard deviation (105 for 2016 - 2021)					
Other Outside Force	Actual	10	11	6	4	6	6
	Baseline	Rolling average since 2016 + 0.5 standard deviation (9 for 2016 - 2021)					
Material or Welds	Actual	2	2	4	2	1	3
	Baseline	Rolling average since 2016 + 0.5 standard deviation (3 for 2016 - 2021)					
Equipment Failure	Actual	98	74	135	24	25	39
	Baseline	Rolling average since 2016 + 0.5 standard deviation (95 for 2016 - 2021)					
Incorrect Operations	Actual	0	0	0	2	1	1
	Baseline	Rolling average since 2016 + 0.5 standard deviation (1 for 2016 - 2021)					
Other	Actual	211	215	340	281	131	134
	Baseline	Rolling average since 2016 + 0.5 standard deviation (275 for 2016 - 2021)					
Total	Actual	752	812	926	727	429	581
	Baseline	Rolling average since 2016 + 0.5 standard deviation (821 for 2016 - 2021)					

Appendix E, Section 2 – Number of Excavation Damages

The 5 years baseline and ongoing performance of the number of excavation damages is provided below (Including Excavation Damage Leaks):

INCLUDING Damage

Rhode Island		2016	2017	2018	2019	2020	2021
Excavation Damages	Actual	106	116	95	102	117	94
	Baseline	Rolling average since 2016 + 0.5 standard deviation (112 for 2016 - 2021)					

Appendix E, Section 3 – Number of Excavation Tickets

The 5 years baseline and ongoing performance of the number of excavation tickets is provided below (Including Excavation Damage Leaks):

INCLUDING Damage

Rhode Island		2016	2017	2018	2019	2020	2021
Excavation Tickets	Actual	63,541	53,550	43,022	43,444	41,123	43,930
	Baseline	Rolling average since 2016 + 0.5 standard deviation (53,685 for 2016 - 2021)					

Appendix E, Section 4 – Total Number of Leaks Either Eliminated or Repaired, Categorized by Cause

The baseline and ongoing performance of the number of Leaks Either Eliminated or Repaired, Categorized by Cause is provided below (Including Excavation Damage Leaks):

INCLUDING Damage

Rhode Island

Cause		2016	2017	2018	2019	2020	2021
Corrosion	Actual	480	562	435	465	407	569
	Baseline	Rolling average since 2016 + 0.5 standard deviation (499 for 2016 - 2021)					
Natural Forces	Actual	41	28	97	69	18	27
	Baseline	Rolling average since 2016 + 0.5 standard deviation (67 for 2016 - 2021)					
Excavation Damage	Actual	107	117	100	97	77	119
	Baseline	Rolling average since 2016 + 0.5 standard deviation (107 for 2016 - 2021)					
Other Outside Force	Actual	10	11	6	5	6	11
	Baseline	Rolling average since 2016 + 0.5 standard deviation (9 for 2016 - 2021)					
Material or Welds	Actual	4	2	7	6	4	5
	Baseline	Rolling average since 2016 + 0.5 standard deviation (6 for 2016 - 2021)					
Equipment Failure	Actual	142	132	193	38	47	104
	Baseline	Rolling average since 2016 + 0.5 standard deviation (144 for 2016 - 2021)					
Incorrect Operations	Actual	4	0	0	3	2	4
	Baseline	Rolling average since 2016 + 0.5 standard deviation (3 for 2016 - 2021)					
Other	Actual	568	671	776	840	620	587
	Baseline	Rolling average since 2016 + 0.5 standard deviation (751 for 2016 - 2021)					
Total	Actual	1,356	1,523	1,614	1,523	1,181	1,426
	Baseline	Rolling average since 2016 + 0.5 standard deviation (1,525 for 2016 - 2021)					

Appendix E, Section 5 – Number of Hazardous Leaks Either Eliminated or Repaired, Categorized by Material

The 5 years baseline and ongoing performance of the number of Hazardous (***Type 1***) Leaks for Main and Service combined Either Eliminated or Repaired, Categorized by Material is provided below (Excluding Excavation Damage Leaks):

EXCLUDING Damages

Rhode Island

Cause		2016	2017	2018	2019	2020	2021
Cast Iron / Wrought Iron	Actual	251	247	437	327	148	174
	Baseline	Rolling average since 2016 + 0.5 standard deviation (336 for 2016 - 2021)					
Unprotected Bare	Actual	299	351	276	235	149	229
	Baseline	Rolling average since 2016 + 0.5 standard deviation (300 for 2016 - 2021)					
Unprotected Coated	Actual	29	33	31	22	15	22
	Baseline	Rolling average since 2016 + 0.5 standard deviation (30 for 2016 - 2021)					
Protected Bare	Actual	0	0	0	0	0	0
	Baseline	Rolling average since 2016 + 0.5 standard deviation (0 for 2016 - 2021)					
Protected Coated	Actual	0	0	2	2	0	0
	Baseline	Rolling average since 2016 + 0.5 standard deviation (1 for 2016 - 2021)					
Plastic	Actual	68	57	76	42	41	50
	Baseline	Rolling average since 2016 + 0.5 standard deviation (65 for 2016 - 2021)					
Copper	Actual	0	2	6	3	0	0
	Baseline	Rolling average since 2016 + 0.5 standard deviation (3 for 2016 - 2021)					
Other	Actual	3	6	1	1	1	1
	Baseline	Rolling average since 2016 + 0.5 standard deviation (3 for 2016 - 2021)					
Total	Actual	650	696	829	632	354	476
	Baseline	Rolling average since 2016 + 0.5 standard deviation (719 for 2016 - 2021)					

Appendix E, Section 6 – Number of Excavation Damages

The 5 years baseline and ongoing performance of the number of known system leaks at the end of the year scheduled for repair is provided below:

Workable Leak Backlog		2016	2017	2018	2019	2020	2021
Rhode Island	Actual	68	74	169	164	155	188
	Baseline	Rolling average since 2016 + 0.5 standard deviation (151 for 2016 - 2021)					

The 5 years baseline and ongoing performance of total damages per 1000 tickets is provided below (**INCLUDING** Excavation Damage Leaks):

Total Excavation Damages per 1000 Tickets		2016	2017	2018	2019	2020	2021
Rhode Island	Actual	1.67	2.17	2.21	2.35	2.55	2.14
	Baseline	Rolling average since 2016 + 0.5 standard deviation (2.35 for 2016 - 2021)					

The 5 years baseline and ongoing performance of Total Leak Receipts is provided below (**EXCLUDING** Excavation Damage Leaks):

Total Leak Receipts		2016	2017	2018	2019	2020	2021
Rhode Island	Actual	1,964	1,924	1,989	2,107	1,738	1,507
	Baseline	Rolling average since 2016 + 0.5 standard deviation (2,011 for 2016 - 2021)					

The baseline and ongoing performance of the Response Time Performance are provided below:

Regular Day							
Response Time		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
30 Minutes	Actual	95.05%	95.48%	94.94%	94.94%	96.62%	96.94%
	Baseline	93.97% as established by RI PUC					

Nights & Weekends							
Response Time		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
45 Minutes	Actual	96.10%	95.69%	96.17%	96.17%	97.24%	98.24%
	Baseline	94.38% as established by RI PUC					

The baseline and ongoing performance of the Main Leak Rates (LEAK REPAIRS BY MILE OF MAIN) by Material are provided below (Excluding Excavation Damage Leaks):

EXCLUDING Damages

Main Leak Rates (LEAK REPAIRS BY MILE OF MAIN) by Material							
Rhode Island		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Cast Iron	**Actual**	0.83	0.98	1.25	1.22	0.98	1.05
	Baseline	Rolling average since 2016 + 0.5 standard deviation (1.14 for 2016 - 2021)					
All Steel	**Actual**	0.11	0.12	0.14	0.13	0.08	0.11
	Baseline	Rolling average since 2016 + 0.5 standard deviation (0.13 for 2016 - 2021)					
Plastic	**Actual**	0.01	0.01	0.01	0.01	0.00	0.01
	Baseline	Rolling average since 2016 + 0.5 standard deviation (0.01 for 2016 - 2021)					

The baseline and ongoing performance of the Service Leak Rates (LEAK REPAIRS BY 1000 SERVICES) by Material are provided below (Excluding Excavation Damage Leaks):

EXCLUDING Damages

Service Leak Rates (leak repairs per 1000 services) by Material Excluding Damages							
Rhode Island		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Copper	**Actual**	0.00	26.04	37.04	22.73	0.00	0.00
	Baseline	Rolling average since 2016 + 0.5 standard deviation (25.43 for 2016 - 2021)					
All Steel	**Actual**	7.94	9.81	7.71	7.56	5.89	8.70
	Baseline	Rolling average since 2016 + 0.5 standard deviation (8.48 for 2016 - 2021)					
Plastic	**Actual**	0.54	0.45	0.65	0.43	0.42	0.65
	Baseline	Rolling average since 2016 + 0.5 standard deviation (0.55 for 2016 - 2021)					

RHODE ISLAND
APPENDIX F
PERIODIC EVALUATION AND IMPROVEMENT

2021 REGIONAL DISTRIBUTION INTEGRITY ASSESSMENT

Distribution Engineering has reviewed all of the findings in the annual Trend-Based Distribution System Integrity Analysis (System Integrity Report) in accordance with our Distribution Integrity Management Plan (DIMP). There are no immediate causes for concern that would warrant changes to DIMP.

Below is a summary of the individual key integrity measure results for the following federal (PHMSA) filing entities that constitute National Grid-US.

NATIONAL GRID 2021 System Integrity Report Summary	
REGIONS **ITEMS**	**RI**
• **Leak Receipts**	Decrease
• **Workable Leak Backlog**	Increase
• **LPP Main and Service Inventories**	Decrease
• **Overall Main Leak Rate**	Decrease
• **Cast Iron Main Break Rate**	Decrease
• **Steel Main Corrosion Leak Rate**	Increase
• **Service Leak Rate**	Increase

Form F-1: Periodic Updating and Review (Region: RI)

Annual Evaluation of Performance Measures that Exceeded Baseline				
Performance Measure	**Actual Performance for Year 2021**	**Established Baseline**	**Are additional measures beyond minimum code requirement necessary?**	**Has an engineering evaluation been completed and documented?**
Leak Receipts	1,507	2,011	NO	Annual System Integrity Report
Workable leak Backlog	188	151	NO	Annual System Integrity Report
LPP Main Inventory	942 miles	989 miles (2020)	NO	Annual System Integrity Report
Overall Main Leak Rate	0.24	0.28	NO	Annual System Integrity Report
Cast Iron Main Break Rate	0.04	0.09	NO	Annual System Integrity Report
Steel main Corrosion Leak Rate	0.14	0.10	NO	Annual System Integrity Report
Service Leak Rate	3.26	2.68	NO	Annual System Integrity Report
Existing Date for Complete Program re-evaluation:____08/2/2026______ Is a shorter timeframe for complete program re-evaluation warranted? : __NO____ **Complete Re-evaluation was performed on 08/02/2021 - DIMP REV 10** Laeyeng Hunt (Director) and Barry Foster (DIMP Manager) Gas Distribution Engineering				

Required frequency	Program Re-evaluation Element	Date Completed
Required Annually	Evaluate Performance Measures	8/2/2022
As needed	Update Knowledge of System Characteristics, Environmental Factors and Threats	8/2/2022
As needed	Update General Information	8/2/2022
As needed	Update Threat Identification	8/2/2022
As needed	Update Risk Evaluation and Ranking Process	8/2/2022
Required Annually	Update Risk Evaluation and Ranking of Risks	8/2/2022
As needed	Update Risk Evaluation and Ranking Validation	8/2/2022
As needed	Update Risk Evaluation and Ranking Process Improvement Action Plans	8/2/2022
As needed*	Update Action Plans	

RHODE ISLAND
APPENDIX G
CROSS REFERENCE OF 49 CFR PART 192, SUBPART P REQUIREMENTS TO THE DIM PLAN

The table below provides a cross reference between 49 CFR Part 192, Subpart P (Gas Distribution Pipeline Integrity Management) and this Gas Distribution Integrity Management Plan.

49 CFR Part 192, Subpart P	DIM Plan Reference
§192.1005 No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in § 192.1007.	4.0
§192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:	
§192.1007 (a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.	6.0
§192.1007 (a) (1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.	6.3
§192.1007 (a) (2) Consider the information gained from past design, operations, and maintenance.	6.2
§192.1007 (a) (3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).	6.4
§192.1007 (a) (4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.	11.0
§192.1007 (a) (5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.	6.5
§192.1007 (b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material, weld or joint failure, equipment failure, incorrect operation, and other concerns that could threaten the integrity of the pipeline.	7.0
§192.1007 (b) An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.	6.1, 7.0
§192.1007 (c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure.	8.0
§192.1007 (c) An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.	Non-Mandatory

49 CFR Part 192, Subpart P	DIM Plan Reference
§192.1007 (d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).	9.0
§192.1007 (e) (1) *Measure performance, monitor results, and evaluate effectiveness.* Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. …… These performance measures must include the following: (i) Number of hazardous leaks either eliminated or repaired, per § 192.703(c), categorized by cause; (ii) Number of excavation damages; (iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center); (iv) Total number of leaks either eliminated or repaired, categorized by cause; (v) Number of hazardous leaks either eliminated or repaired per § 192.703(c), categorized by material; and (vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.	10.0
§192.1007 (e) (1) *Measure performance, monitor results, and evaluate effectiveness.* …. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks.	11.2
§192.1007 (f) *Periodic Evaluation and Improvement.* An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas.	8.1, 11.1
§192.1007 (f) Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. The operator must conduct a complete program reevaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.	11.2
§192.1007 (g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by § 191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.	12.1
§192.1009 Each operator must report, on an annual basis, information related to failure of mechanical fittings, excluding those that result only in nonhazardous leaks, as part of the annual report required by §191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.	12.1
§192.1011 An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.	13.0

49 CFR Part 192, Subpart P	DIM Plan Reference
§192.1013 (a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. (b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall leve0l of safety. (c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.	Not covered by DIM Plan

PUC 4-12
Leak Prone Pipes (LPP)

Request:

If the most recent DIMP does not include data through 2022, please provide the most up-to-date versions of Tables A-1 and A-2 including the most recent data.

Response:

Tables A-1 and A-2 have not yet been prepared for the 2022 DIMP Report. The Tables in the 2021 DIMP Report, provided as Attachment PUC 4-11, are the most recent.

Prepared by or under the supervision of: Barry J. Foster

PUC 4-13
Leak Prone Pipes (LPP)

Request:

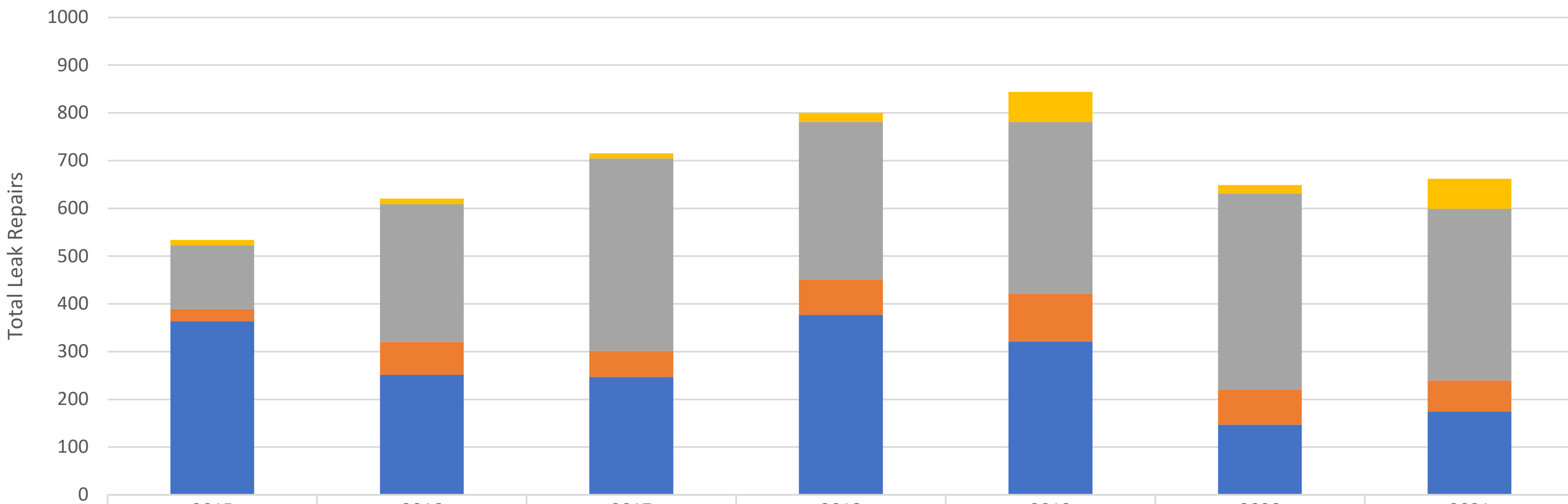
If possible, please provide a bar chart and table like the information on Bates 99 –Leak Repaired by Type (included damages) but for only cast iron mains and excluding damages.

Response:

Please refer to Attachment PUC 4-13. The data necessary to create the chart provided in Attachment PUC 4-13 is only available dating back to 2015 (as opposed to the 2012 lookback used to create the referenced chart/table).

Prepared by or under the supervision of: Corey Hogg

Total Cast Iron Leak Repairs
(Excluding Damages)



	2015	2016	2017	2018	2019	2020	2021
Type 3	11	12	11	19	63	18	63
Type 2	134	289	403	329	360	410	359
Type 2A	25	69	55	75	100	74	66
Type 1	364	251	247	377	321	147	174

Year

Type 1 Type 2A Type 2 Type 3

PUC 4-14
Leak Prone Pipes (LPP)

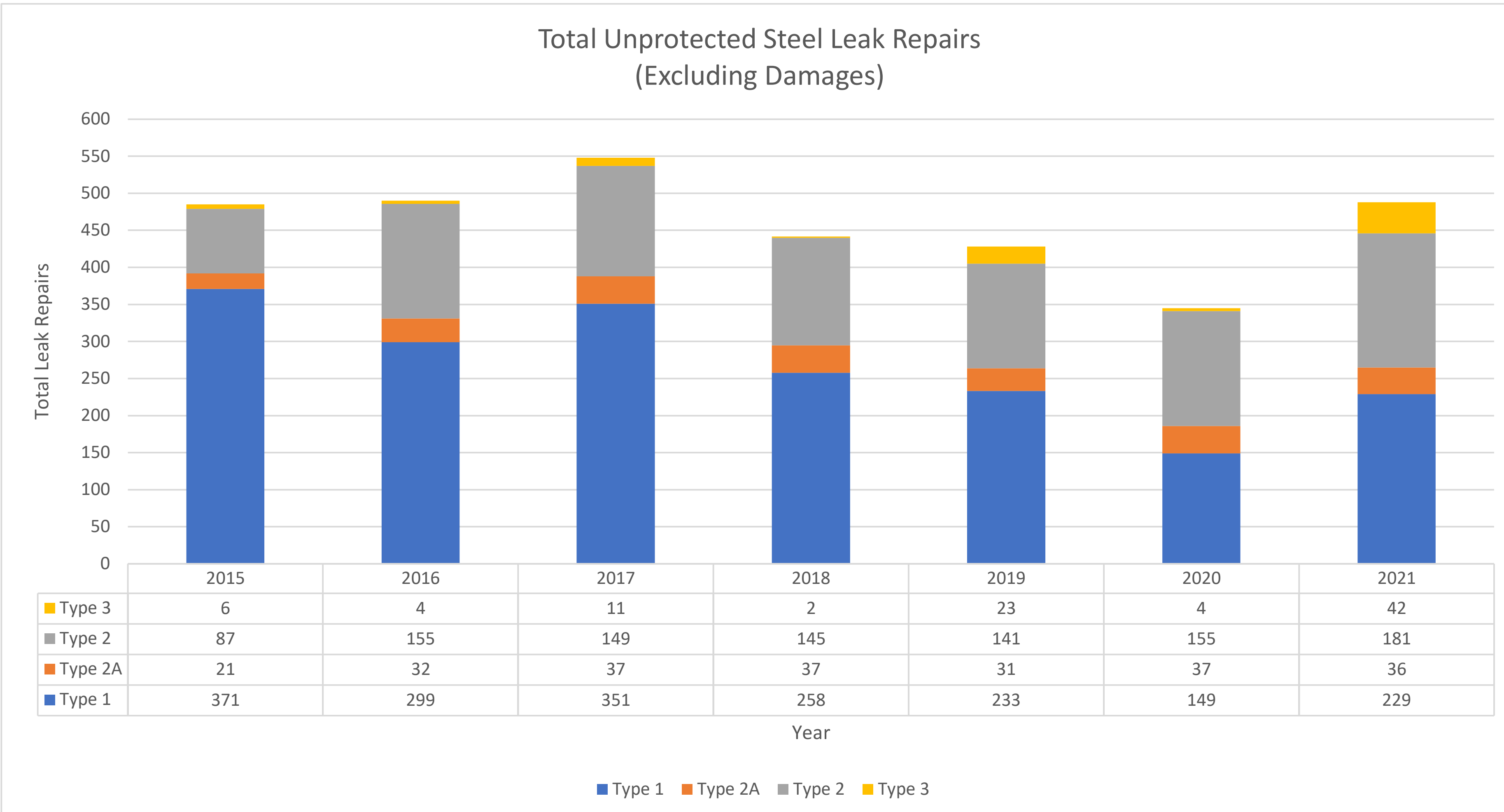
Request:

Please provide the same as 4-13 but for unprotected steel.

Response:

Please refer to Attachment PUC 4-14. Data to create the chart contained in Attachment PUC 4-14 was only available dating back to 2015 (as opposed to the 2012 lookback used to create the chart/table referenced in Bates 99).

Prepared by or under the supervision of: Corey Hogg



	2015	2016	2017	2018	2019	2020	2021
Type 3	6	4	11	2	23	4	42
Type 2	87	155	149	145	141	155	181
Type 2A	21	32	37	37	31	37	36
Type 1	371	299	351	258	233	149	229

PUC 4-15

Leak Prone Pipes (LPP)

Request:

Regarding the data on Bates 112, do "CI Joint Leaks" what Leak Type do these leaks fall in?

Response:

Cast Iron joint leaks can fall under any of the 4 leak types (1, 2A, 2, and/or 3) depending on how they are classified by the Company. Attachment PUC 4-15 is a copy of the Company's Gas policy, Classifying Gas Leaks – CNST02009, outlining how leaks are classified.

Prepared by or under the supervision of: Corey Hogg

Classifying Gas Leaks – CNST02009

1. Purpose

The purpose of this document is to state Rhode Island Energy's policy for classifying leaks.

This document covers:

- Classification of gas leak migration patterns
- Leak grade reclassification
- Leak repair schedule

Leaks on above ground (exposed) piping should not be classified and shall be handled in accordance with Emergency Response Procedures (See **First Responder CNST02013**).

Leaks inside a structure, downstream of the service valve, shall be repaired or made safe in accordance with **Warning Tag Procedure CMS04009**.

2. Responsibilities

Gas Operations or designee shall:

- Serve as the lead organization for this policy document
- Classify leak migration patterns

Customer Meter Services or a designee shall:

- Provide clerical support for leak management
- Maintain a leak database
- Scan leak classification tickets and maintain on a shared drive
- Classify leak migration patterns
- Document results of investigation on the Leak Investigation Report (Green Leak Ticket)

3. Personal & Process Safety

Leaks shall be classified in accordance with this policy document.

Surveillance schedules are found in **CNST02011**.

Leak Response and Repair is found in **CNST02010**.

4. Operator Qualification Required Tasks [Qualified or Directed & Observed]

Please refer to the OQT&C Task-to-Title Matrices for the applicable OQ Requirement(s) for performing work in accordance with this document.

Not all personnel shall be required to perform all tasks associated with this document. Therefore, Operations personnel shall only be required to qualify on those tasks associated with the tasks they will perform.

5. Content

5.1. Classification of Leaks – General

a. Pipeline leaks on below ground facilities have the potential to migrate to nearby structures or substructures, where they may accumulate to combustible levels. The purpose of classifying below ground gas leaks is to assign the appropriate hazard classification based on the potential for leak migration.

b. During the defined Winter Operations period, newly discovered leaks should be classified under the guidance for continuous pavement (left side of leak classification guide). Leaks may be re-evaluated in the weeks following suspension of the Winter Operations period. See **Winter Leak Operations CNST02004.**

c. Leaks on above ground piping shall not be classified

   1) Above ground piping is defined as piping that is not buried below ground and which presents no migration hazard to surrounding structures or sub-structures. Outside leaks on above ground piping vent freely into the atmosphere and therefore present no below ground migration or accumulation hazard. For this reason, leaks on above ground piping (e.g., meter headers, above ground regulator stations, mains on bridges, etc.) shall not be classified (Grade 1, 2A, 2 or 3), nor documented on the standard Leak Classification (Green) Form. However, an appropriate priority shall be applied to remediation based on the severity of the hazard as noted below.

   2) For above ground leaks, a determination shall be made if the leak presents an immediate hazard or if it is considered non-hazardous as described in the procedure document: **First Responder CNST02013.**

d. Individual below ground leak classification shall be determined based on percentage of gas, surface conditions, and proximity to confined spaces, including buildings and sub-structures, as specified in the applicable leak classification guidelines, see **Attachment 1 CM4 Leak Classification Guide.**

e. For the purpose of classifying leaks in manholes, sustained readings on a CGI shall be taken in an enclosed atmosphere either by:

   1) Inserting the probe of the CGI through the manhole cover vent holes, or

   2) By cracking the seal open of the manhole cover slightly (e.g., prying open) to allow the insertion of the CGI probe into the outer edge crack of the manhole for atmosphere readings in the manhole, without substantially venting the reading to a lesser concentration

5.2. Grade 1 Leaks

a. Grade 1 leak migration pattern is a gas leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the condition is no longer hazardous.

Grade 1 leak migration patterns include, but are not limited to the following:

1) Damage to gas facilities resulting in leakage.
2) Blowing gas and/or strong unlocatable odor of gas.
3) Any indication on a combustible gas indicator of natural gas migrating into a structure.
4) Any leak which, in the judgment of the operating personnel at the scene, is regarded as hazardous.

5.3. Grade 2A Leaks

a. Grade 2A leak is a gas leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard and shall be scheduled for surveillance until repaired.

5.4. Grade 2 Leaks

a. Grade 2 leak is a gas leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard and shall be scheduled for surveillance until it is repaired.

5.5 Grade 3 Leaks

a. Grade 3 leak is a gas leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous and does not require repair, however, shall be scheduled for surveillance annually.

5.6 Leak Reclassification

a. The classification of a leak migration pattern shall be upgraded after only one increased reading of a higher classification, in the level of natural gas.

b. If the Grade 1 leak has been repaired, yet after re-check still has gas readings, it may be reclassified to the appropriate grade.

c. In situations in which no repair has been affected and the leak is demonstrating readings of a lower classification:

A. Grade 1 leak:

Where a Grade 1 leak demonstrates readings of a lower classification, or no reading, at the time of the hand off between the repair crew and the first responder, before repair action is taken, the company shall document the bar hole readings and the leak may be classified or canceled.

B. For a Grade 2A, 2, and 3 leaks:

If a leak demonstrates readings of a lower classification during surveillance, or at the time of a scheduled repair, at which time the leak may be downgraded or closed based on readings.

Leak Repair Schedule

a. Grade 1 Leaks:

1. Grade 1 leaks require continuous action to be taken, or a repair to be affected, until the condition is deemed no longer hazardous.
2. The repair crew shall verify all previously recorded readings prior to commencing and pinpoint or repair work.
3. The repair crew shall document post repair readings upon completion of repair(s).

b. Grade 2A Leaks:

1. Repair of a grade 2A leak should be made within 6 months from the date the leak was classified at this classification.
2. The repair crew shall verify all previously recorded readings prior to commencing and pinpoint or repair work.
3. The repair crew shall document post repair readings upon completion of repair(s).

c. Grade 2 Leaks:

1. Repair of a grade 2 leak should be made within 12 months from the date the leak was classified at this classification.
2. The repair crew shall verify all previously recorded readings prior to commencing and pinpoint or repair work.
3. The repair crew shall document post repair readings upon completion of repair(s).

d. Grade 3 Leak:

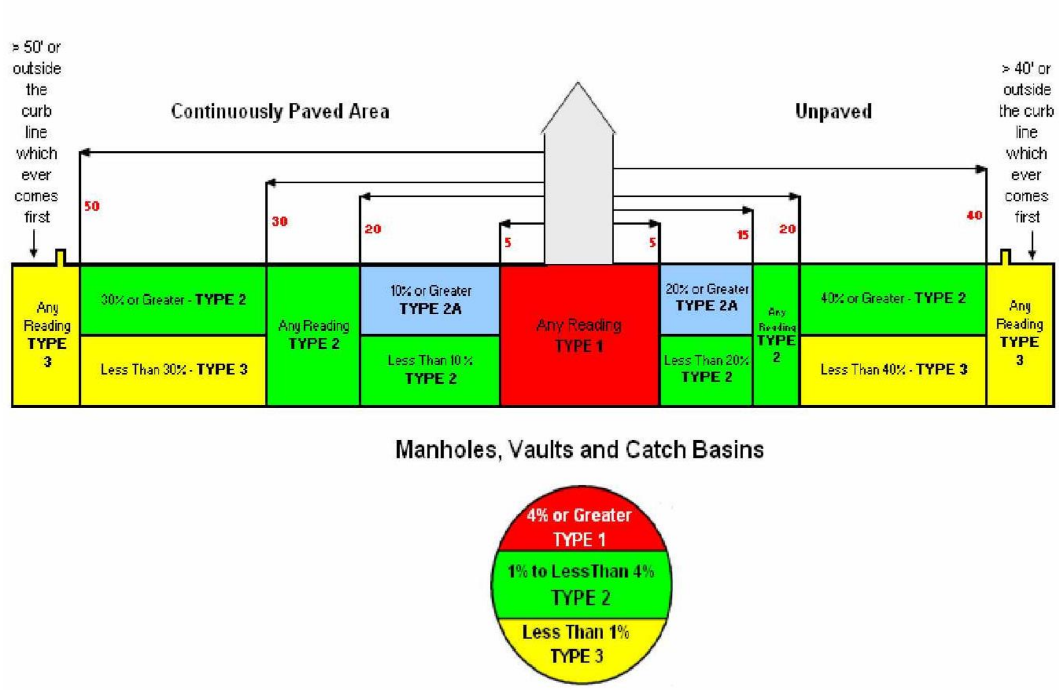
1. Grade 3 leaks are considered non-hazardous in nature and do not require a set repair schedule.
2. The company may schedule a Grade 3 leak for repair at any time. Reasons include, but are not limited to Pre-paving surveys, nuisance leaks, high volume leaks, or any other reason the company deems necessary.

6. Attachments

Attachment 1: Leak Classification Guide CM4

Rhode Island Energy™	Gas Policy **Leak Control**	Doc. # **CNST02009** Page 5 of 5
	Classifying Gas Leaks	Revision 0 – 12/1/2022

Attachment 1: Leak Classification Guide CM4



PUC 4-16
Leak Prone Pipes (LPP)

Request:

Does the company have any forecast of the number and types of leaks that are likely to be avoided (or the change in leak rate on mains, or any other analogous metric) for the period after the FY24 Proactive Main Program is implemented as a result of the program? If so, please provide the forecast and foundation.

Response:

An analogous metric has not been established to forecast the change in leaks that may be avoided after FY 2024. The downward trend in diminishing leak receipts shows the benefit in replacing leak prone pipe. Annual leak receipts year-over-year can fluctuate based upon weather, customer awareness and survey cycles. The Company uses trend analysis to evaluate overall performance.

Prepared by or under the supervision of: Barry J. Foster

PUC 4-17
Emissions

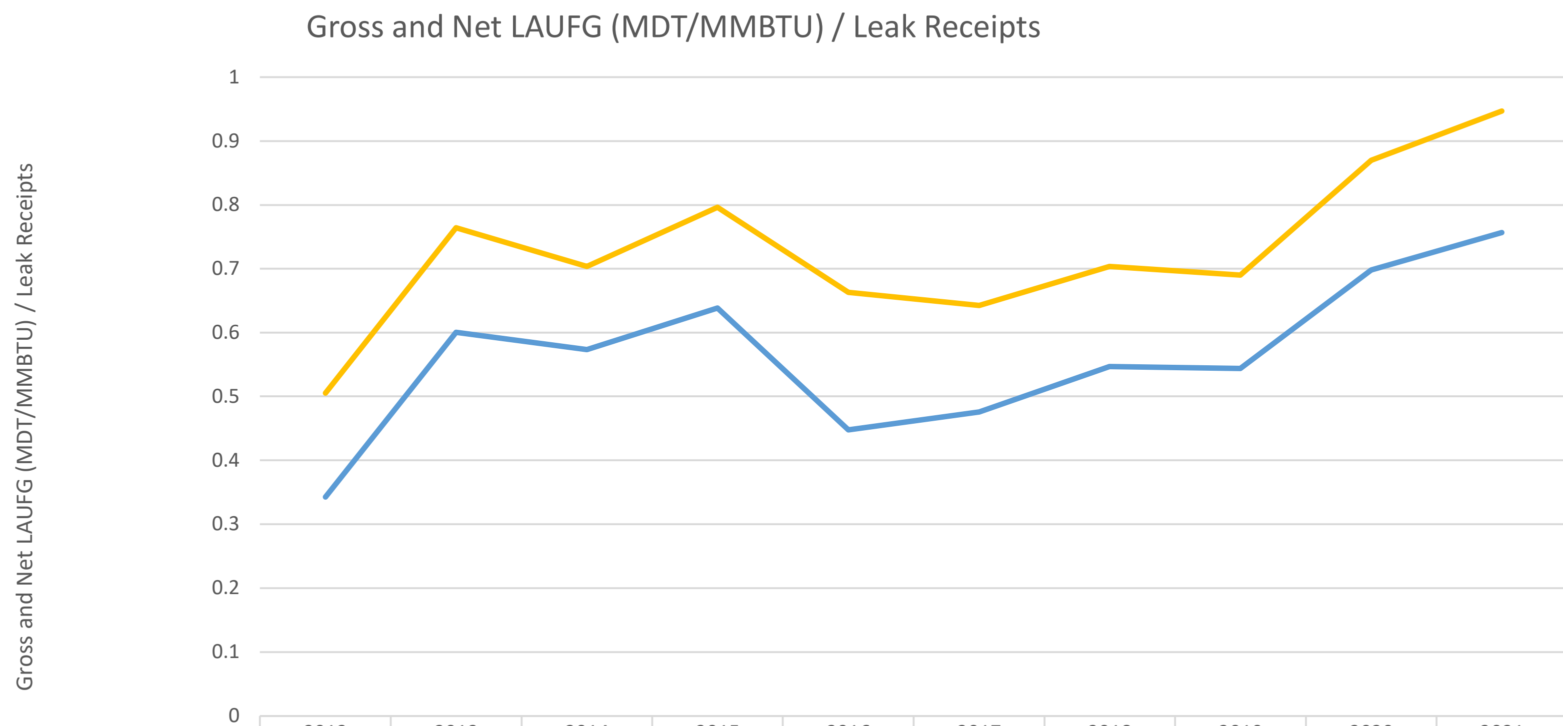
Request:

Referencing RIE's response to Division 1-4, please plot a graph of Gross LAUF divided by Leak Receipts from 2011 to present (or, 2012, if data does not go back farther). On the same graph, plot Net LAUF divided by leak receipts.

Response:

Please see Attachment PUC 4-17.

Prepared by or under the supervision of: Corey Hogg



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Gross LAUFG (MDT/MMBTU)	1,222	1,721	1,937	1,738	1,022	1,236	1,399	1,454	1,512	1,428
Net LAUFG (MDT/MMBTU)	828	1,352	1,580	1,395	690	915	1,088	1,146	1,213	1,141
Leak Receipts	2,417	2,252	2,753	2,183	1,541	1,924	1,989	2,107	1,738	1,508
Gross LAUFG (MDT/MMBTU) / Leak Receipts	0.506	0.764	0.704	0.796	0.663	0.642	0.703	0.690	0.870	0.947
Net LAUFG (MDT/MMBTU) / Leak Receipts	0.343	0.601	0.574	0.639	0.448	0.476	0.547	0.544	0.698	0.757

Gross LAUFG (MDT/MMBTU) / Leak Receipts   Net LAUFG (MDT/MMBTU) / Leak Receipts

PUC 4-18
Emissions

Request:

Referencing RIE's response to Division 1-2, please provide the details of the "system change" in 2019 and why it caused an apparent increase in emissions reporting.

Response:

From the Company's review of the legacy reports, there was a conversion of the Company's GIS System that led to an increase in the accuracy of the Company's overall service pipe lengths. This increased the overall total of the Company's service pipe inventory. When the Company inputted the new (increased total) service lengths into the EPA formula for emissions, the leak prone service inventory increased and essentially cancelled out any emissions reductions resulting from the abandonment of leak prone pipe (mains and services) for that year. From that point forward, there is an annual reduction in leak prone pipe (mains and services) inventory in the GIS System, which results in a year-over-year lower emissions factor (reduction) from the Company's gas distribution system.

Prepared by or under the supervision of: Barry J. Foster

PUC 4-19
Emissions

Request:

Please update the response to 3-23 in Docket 5210, regarding LAUF and emissions. Please include three analogous rows for Gross LAUF and Total Emissions.

Response:

Please refer to Attachment PUC 4-19. Please note, the emission factor has been updated to 0.0551 metric tons of CO2/MCF. The previous value was 0.0548 metric tons (Source: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-revision-history)

Prepared by or under the supervision of: Corey Hogg

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Net Lost and Unaccounted For Gas (LAUF) in MDT	1,086	822	1,346	1,573	1,395	690	915	1,088	1,146	1,213	1,141
Net LAUF in Metric Cubic Feet (MCF)	1,058,425.25	801,169.59	1,311,890.84	1,533,138.40	1,359,522.84	672,514.62	891,812.87	1,060,428.85	1,116,959.06	1,182,261.21	1,112,085.77
Metric Tons of CO2 Equivalent	58,319.23	44,144.44	72,285.19	84,475.93	74,909.71	37,055.56	49,138.89	58,429.63	61,544.44	65,142.59	61,275.93

Note:
https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-revision-history

MCF of natural gas : The emission factor has been updated to 0.0551 metric tons of CO2/MCF. The previous value was 0.0548 metric tons.

PUC 4-20

Emissions

Request:

Referencing the forecasted emissions reductions calculated by RIE in response to Division 1-4:

a. Please calculate the emissions reduction for a single year associated with the 53 miles forecasted in the Proactive Main Program,

b. Please recalculate the emissions reduction for a singly year if the forecasted miles were reduced by ten miles, and assuming all miles were cast iron.

c. Please calculate the incremental cost of carbon emissions by delaying remediation of these ten hypothetical miles by one, two, and three years (please use the same avoided cost of carbon as used in the most recent energy efficiency BCA).

Response:

a. The emissions reduction for a single year associated with the current work/material mix planned to be completed under the Proactive Main Replacement program is 11,729.53 MCF. The emission factors from Table W-7 from the following link were used in the calculation: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W. Please note, this calculation was done using the planned work/material mix as of March 7, 2023 and the exact work/material mix is subject to change.

b. The emissions reduction for a single year for the scenario presented would be 9,175.14 MCF. The calculation was performed using the same process as was used in part a), except for the portion of the calculation relating to mains, in which the abandonment of cast iron was reduced by 10 miles and the service totals were adjusted accordingly (in proportion).

c. The difference in emissions reduction between scenario a) and scenario b) is 2,554.39 MCF. Through consultation with colleagues familiar with the most recent energy efficiency BCA, dollar amounts were established for avoided carbon costs in dollars per MMBtu (established for the present year 2023) as a result of delaying emissions reduction by 1, 2, and 3 years. , By not performing the hypothetical abandonment, the Company would not be avoiding associated carbon costs for the 1, 2, and 3 year time periods. To get the incremental cost of delaying the abandonment of these main segments as requested, the difference in emissions reduction between scenario a) and

PUC 4-20, Page 2

Emissions

b) (2,554.39 MCF) was converted to MMBtu and multiplied by the established $/MMBtu factors. The calculated incremental cost of carbon emissions which would result from the hypothetical scenario presented would be $26,072, $46,249, and $66,523 for a 1, 2, and 3 year delay, respectively.

PUC 4-21
System Reliability Procurement—LNG—Weld Shop

Request:

Regarding the decisions to purchase portable LNG equipment:

a. Who does RIE understand bears the risk of obsolescence of this equipment if RIE purchases the equipment as part of the FY24 Plan?

b. Did RIE weigh the risk of obsolescence of the equipment in light of the Act on Climate when determining to buy, rather than rent, the equipment? If so, please provide that analysis. If not, please explain why.

c. Please explain how, if at all, this nature of this procurement decision is different from the proposal to procure heaters that was thoroughly examined by the PUC during the FY23 Plan review in Docket 5210.

Response:

a. The Company does not believe there is a risk of obsolescence. Based on the Company's current long-range plan, the equipment is needed to support customer demand. However, if customer demand decreased to the point that the equipment became no longer necessary at the Cumberland LNG site it could be repurposed at another Company location (if needed) or sold with sale proceeds credited to the customers, via the ISR. The equipment and operation are scalable and can be adjusted to maintain alignment with customer demand.

b. Yes, please see the Company's response to Division Response 1-39 for the analysis the Company performed regarding the purchase of the portable LNG equipment vs. leasing.

c. The Company's decision to purchase portable LNG equipment for Cumberland, instead of renting or using contracted services is different from the decisions made for the procurement of gas heaters in Docket No. 5210. Currently, Rhode Island Energy does not own any portable LNG equipment. The Company's purchasing decision was based upon the following justifications:

  - The market for portable equipment is increasing, particularly in New England with constrained interstate pipeline capacity. By purchasing equipment, the

PUC 4-21, Page 2
System Reliability Procurement—LNG—Weld Shop

Company is more able to control availability and cost to provide adequate supply under design day conditions.

- As discussed in Division Response 1-39, the Company expects the equipment's purchase price to be recouped within seven years through the avoidance of rental and contractor labor charges. After a permanent solution is in place the equipment will be repurposed at another location or sold with proceeds credited to customers, via the ISR.

- Purchased equipment will decrease the response time to vaporize that is currently experienced with contracted services as the staffing and equipment will be mobilized in Cumberland year-round.

- Purchased equipment ensures that the Company will have equipment to support customer demand, whereas contracted or rented equipment can vary each season.

- Purchased portable equipment is scalable, can be repurposed at other Company locations, or sold with proceeds credited to customers, via the ISR.

PUC 4-22
System Reliability Procurement—LNG—Weld Shop

Request:

Regarding RIE's response to PUC 1-5a, RIE explains that having "only one welding supervisor" is a constraint that leads to a "logistical challenge and inefficiency" that RIE seeks to address with the Weld Shop project. Please explain why hiring one or more incremental welding supervisors would not also solve the constraint? If an alternatives analysis was performed rejecting this non-capital alternative, please provide it. If not, please explain why one was not performed.

Response:

Only having one welding supervisor was a factor when determining how to approach the build out of a new welding space, but it was not the main driver of the decision to construct the Weld Shop. The main driver of the Company's decision to construct the Weld Shop was the inadequacy of the current facilities to support the Company's Gas ISR work. The Company performed an initial analysis on whether to construct one or two facilities and quickly determined that one centrally located facility would be more economical from a capital investment perspective and operational standpoint. One benefit of having a single centralized Weld Shop was the ability to have a single welding supervisor at one facility. Training and qualification of both internal and external welding resources will be provided at one facility. Oversight of internally fabricated projects will also be condensed. The Company did not perform a cost comparison of adding an additional welding supervisor because it was not a primary factor in the decision to build the proposed Weld Shop, though it was a factor that tended to support the Company's decision to construct a single facility. Additional conversations have taken place regarding the need for additional welding department personnel, that are unrelated to the need for building the Weld Shop, but those additional department personnel would support the overall operations of welding in order to ensure compliance and system safety.

PUC 4-23
Low Pressure System

Request:

Are there any areas of low pressure mains, other than the Middletown portion already planned for remediation, that will need to be addressed in future years. If so, please provide some geographic and basic count statistics for these area (e.g., miles, customers, etc.), if known.

Response:

The Middletown low-pressure ("LP") system is one of three remaining LP single feed systems remaining on the Rhode Island gas system throughout the state. There is one in Warren, where the LP regulator station is located at Market Street @ Kickemuit Road. The other is in Lincoln, which is actively being replaced with high-pressure ("HP") gas.

LP Single Feed System Descriptions:

Station RIS-BW014 – Market Street @ Kickemuit Road LP – Warren
Length of LP mains – 1.46 miles
Customers – 231

Station RIN-C014 – Railroad Street @ Winter Street LP – Lincoln
Length of LP mains – 3.92 miles
Customers - 421

PUC 4-24
Retroactive Rate Recovery

Request:

Refer to the Testimony of Kocon & Hunt at page 14, which states:

"The Company intends to seek recovery of this equipment purchase during the FY 2023 ISR Reconciliation process;" and page 15 which states: "The Company will also seek recovery of this tool purchase during the FY 2023 ISR Reconciliation process"

a. Please explain whether the Company intends to seek retroactive recovery of all or a portion of the revenue requirement incurred prior to April 1, 2023, or only the prospective revenue requirement incurred on and after April 1, 2023.

b. Please provide a list of all investments that were made during FY 2023 which were not approved by the Commission in the FY 2023 ISR plan for which the Company will be seeking any retroactive recovery of revenue requirement in the FY 2023 Reconciliation process.

Response:

a. The Company does not intend to seek retroactive recovery of any portion of the revenue requirement incurred prior to April 1, 2023 because the Company's current FY 2023 forecast for Projected Capital Additions Placed In-Service, including the Tools & Equipment purchases referenced in the Joint Rebuttal Testimony of Company witnesses Nathan Kocon & Laeyeng H. Hunt at page 14 does not exceed the FY 2023 target of $162.924 million.

   The FY 2023 revenue requirement component of the proposed FY 2024 rates to be implemented on April 1, 2023, assume that the FY 2023 Projected Capital Additions Placed In-Service will be at target; therefore, the Tools & Equipment purchases will be included in the prospective revenue requirement incurred on and after April 1, 2023. Notwithstanding the above, other factors, such as revenue from the sale of gas during FY 2023, will be considered in the calculation of the FY 2023 Reconciliation factor to determine if any over/under collections result in any corresponding credits/adjustment charges to customers.

b. There were no investments that were made during FY 2023 which were not approved by the Commission in the FY 2023 ISR Plan for which the Company believes it will be seeking any retroactive recovery in the FY 2023 Reconciliation process.

Prepared by or under the supervision of: Nathan Kocon and Stephanie A. Briggs

PUC 4-24, Page 2
Retroactive Rate Recovery

Notwithstanding the above, the following investments were made in FY 2023 that constitute variances from the approved budgets for FY 2023:.

- The ongoing **Allens Avenue Multi Station Rebuild** project has been included in the Gas ISR plans prior to FY 2023, and is an approved investment. Spending for this project was not initially included in the FY 2023 Gas ISR Plan budget because the project was originally expected to reach its completion in FY 2022. As of the end of Q3 FY2023, the project was forecast to incur project closeout costs totaling $1.085 million.

- Within the approved FY 2023 **Tools & Equipment** budget category, the notable equipment purchase was the **T.D. Williamson** ProStopp for approximately $0.589 million, which was originally forecasted to arrive/be purchased and go in-service in FY 2024. Because of timing issues outside the control of the Company, this equipment arrived earlier than expected and is currently in use in FY 2023. Please see the Company's response to subpart (a), above for the impact of this equipment purchase on the FY 2023 forecast for Projected Capital Additions Placed In-Service.

- The **Cumberland Portable LNG Equipment,** which the Company identified as a new ISR category instead of including it within the overall LNG category, has a forecasted spend of $7.00 million for FY 2023; however, the Company will not be seeking recovery for any Capital Additions Placed In-Service for this investment within the FY 2023 Reconciliation as the Cumberland Portable LNG Equipment is forecasted to go in-service in FY 2024. Thus, the Company included the Cumberland Portable LNG Equipment in the proposed FY 2024 Gas ISR Plan for review and approval by the Commission.

Prepared by or under the supervision of: Nathan Kocon