The Narragansett Electric Company
d/b/a Rhode Island Energy

Proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan

Responses to Division Data Requests – Set 1

Book 2 of 2

December 22, 2022

Docket No. 22-54-NG

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™

a PPL company

Motion

STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

FY 2024 Gas Infrastructure, Safety and Reliability Plan	)	Docket No. 22-54-NG

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

Rhode Island Energy[1] respectfully requests that the Rhode Island Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as well as certain critical energy infrastructure information as permitted by 810-RICR-00-00-1.3(H) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B) and (4)(F). The Company also respectfully requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On December 22, 2022, the Company submitted its FY 2024 Gas Infrastructure, Safety and Reliability Plan (the "Plan" or "Gas ISR Plan") filing in the above-captioned docket. The Gas ISR Plan filing includes the Company's responses to fifty-one data requests propounded by the Division of Public Utilities and Carriers (the "Division") in connection with its pre-filing review of the Plan. The Company's response to data request Division 1-10, and Attachments DIV 1-8, Attachment DIV 1-35, Attachment DIV 1-38-3, Attachment DIV 1-41-1, and

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

Attachment DIV 1-41-2 (the "Confidential Attachments") contain information that is not subject to disclosure under Rhode Island's Access to Public Records Act. Specifically, the response to Division 1-10, and Attachment DIV 1-8 and Attachment DIV 1-35 contain critical energy infrastructure information ("CEII") the disclosure of which could present a threat to public safety. The CEII contained in the Company's response to Division 1-10 and the Confidential Attachments includes plans, descriptions, design standards and schematic drawings of natural gas transmission and distribution infrastructure. Additionally, Attachment 1-38-3, Attachment 1-41-1, and Attachment 1-41-2 contain certain confidential and commercially sensitive information related the Company's Exeter liquified natural gas ("LNG") Facility and the Company's contractual arrangement with the U.S. Navy for certain LNG facilities in Newport, Rhode Island, respectively, which include pricing and other commercially sensitive information. In addition to sensitive commercial information, Attachment 1-41-1 and Attachment 1-41-2 also contain personally identifiable information of military personnel that has been redacted in order to protect their privacy.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the CEII and confidential commercial information contained in the response to Division 1-10 and the Confidential Attachments.

II. LEGAL STANDARD

Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-

2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) and (4)(F) provide that the following types of records shall not be deemed public:

> (B) Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature…
>
> (F) Scientific and technological secrets and the security plans of military and law enforcement agencies, the disclosure of which would endanger the public welfare and security.

With respect to the commercial information exception to the definition of "public record," the Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal v. Convention Ctr. Auth.*, 774 A.2d 40 (R.I. 2001). The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47.

With respect to other exceptions to the definition of public record, the Rhode Island Supreme Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established by the Court in *Providence Journal v. Kane*, 577 A.2d 661 (R.I. 1990). Under this balancing test, the PUC may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

III. BASIS FOR CONFIDENTIALITY

The commercial information contained in Attachment DIV 1-38-3, Attachment DIV 1-41-1 and Attachment DIV 1-41-2 is confidential and privileged information and is the type of information that Rhode Island Energy would not ordinarily make public. Attachment DIV 1-38-3 is an operational assessment and study of the Exeter LNG facility (the "LNG Study") and was prepared by a third party for National Grid USA. The LNG Study is subject to confidentiality restrictions and is of the type that would not ordinarily be made public. Attachment DIV 1-41-1 and Attachment DIV 1-41-2 contain the lease and operating agreements between the Company and the U.S. Navy for the LNG transfer station in Newport, Rhode Island. This information includes commercial terms such as pricing, trucking details, and Navy identification data. Public disclosure of such information could impair Rhode Island Energy's ability to negotiate advantageous pricing or other terms with the Navy in the future and compromise the safety and security of the LNG site, thereby causing substantial harm to the detriment of the Company and its customers. Attachment DIV 1-41-1 and Attachment DIV 1-41-2 also contain the names of military personnel, their contact information and signatures of the individuals executing the Company's lease and operating agreements with the Navy. This information is not material to this regulatory proceeding and the legitimate interest in maintaining it as confidential significantly outweighs any interest the public might have in accessing it. Accordingly, Rhode Island Energy is providing the information on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

With respect to the CEII contained in the Company's response to Division 1-10 and Attachment DIV 1-8 and Attachment DIV 1-35, CEII is defined by the Federal Energy Regulatory Commission ("FERC") as:

> [S]pecific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
>
> 1. Relates details about the production, generation, transmission, or distribution of energy;
> 2. Could be useful to a person planning an attack on critical infrastructure;
> 3. Is exempt from mandatory disclosure under the [Federal] Freedom of Information Act, 5 U.S.C. § 552; and
> 4. Does not simply give the general location of the critical information.

18 CFR § 388.113(c)(2). In turn, "critical infrastructure" is defined as:

> [E]xisting and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

18 CFR § 388.113(c)(4). The design specifications and schematic drawings, maps and related information contained in the response to Division 1-10 and Attachment DIV 1-8 and Attachment DIV 1-35 fall squarely within FERC's definition of CEII. Public dissemination of this information could pose a grave threat to public health and safety as it could be used to identify vulnerabilities in, and plan attacks against, natural gas transmission and distribution infrastructure. Under the Rhode Island Supreme Court's balancing test set forth in *Providence Journal v. Kane*, the public interest in access to this information is far outweighed by the threat to the public's health and safety that could result from public dissemination of these technical details concerning natural gas infrastructure.

IV. CONCLUSION

For the foregoing reasons, Rhode Island Energy respectfully requests that the PUC grant its Motion for Protective Treatment of the response to Division 1-10 and the Confidential

Attachments. In accordance with Rule 1.3(H) the Company has submitted redacted versions of Division 1-10 and the Confidential Attachments for the public file in this matter and unredacted confidential versions subject to this motion for protective treatment.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a RHODE ISLAND ENERGY

By its attorney,

Jennifer Brooks Hutchinson (Bar #6176)
Rhode Island Energy
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Providence, RI 02907
Tel. 401-316-7429
JHutchinson@pplweb.com

Dated: December 22, 2022

Filing Letters

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PPL Services Corporation
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Phone 401-784-7288

Rhode Island Energy™
a PPL company

November 23, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1 (Batch 1)

Dear Ms. Massaro:

I have enclosed the electronic version of Rhode Island Energy's[1] first batch of responses to the Division's First Set of Data Requests in the above-referenced matter.

The Company received an extension of time until Tuesday, November 29, 2022, in which to submit its remaining responses.

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: 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").

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Rhode Island Energy™
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November 29, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1 (Batch 2)

Dear Ms. Massaro:

I have enclosed the electronic version of Rhode Island Energy's[1] second batch of responses to the Division's First Set of Data Requests in the above-referenced matter.

In batch 2, the Company is providing the following responses: Division 1-4, 1-15, 1-16, 1-18, 1-19, 1-21, 1-22, 1-26, 1-30, 1-33, 1-34, 1-43, 1-45, 1-46, 1-48, 1-49, and 1-51

The Company received an extension of time until Friday, December 2, 2022, to submit its final batch of responses.

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: Leo Wold, Esq.
John Bell, Division
Al Mancini, Division

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Rhode Island Energy™
a PPL company

December 1, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 1 (Batch 3)</u>

Dear Ms. Massaro:

I have enclosed the electronic version of Rhode Island Energy's[1] third batch of responses to the Division's First Set of Data Requests in the above-referenced matter.

In Batch 3, the Company is providing the following responses: Division 1-3, 1-6, 1-7, 1-10, 1-13, 1-20, 1-28, 1-35, and 1-50.

Please be advised that the Company's response to Division 1-10 and Attachment Division 1-35 include site plans that contain critical energy infrastructure information. Due to the highly sensitive and confidential nature of this response and attachment, the Company is providing its response to Division 1-10 and Attachment Division1-35 via a separate link. The Company is providing this information to the Division pursuant to the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022.

The Company received an extension of time until Friday, December 2, 2022, to submit its final batch of responses.

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: John Bell, Division (w/confidential attachment)
Al Mancini, Division (w/confidential attachment)
Leo Wold, Esq.

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Rhode Island Energy™
a PPL company

December 2, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1 (Batch 4)

Dear Ms. Massaro:

I have enclosed the electronic version of Rhode Island Energy's[1] fourth batch of responses to the Division's First Set of Data Requests in the above-referenced matter.

In Batch 4, the Company is providing the following: Division 1-2, Revised Attachment Division 1-16-1, 1-17, 1-38, 1-39, 1-40, 1-41, 1-42, 1-44 and 1-47.

Please be advised that Attachments Division 1-38-2, 1-38-3, 1-41-1, and 1-41-2 contain confidential information. The Company is providing these confidential attachments to the Division pursuant to the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022.

The Company's response to Division 1-1 is pending.

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: John Bell, Division (w/confidential attachment)
Al Mancini, Division (w/confidential attachment)
Leo Wold, Esq.

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Rhode Island Energy™
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December 7, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1 (Complete Set)

Dear Ms. Massaro:

I have enclosed the electronic version of Rhode Island Energy's[1] complete set of responses to the Division's First Set of Data Requests in the above-referenced matter.

In this transmittal, the Company is submitting its response to Division 1-1, together with Attachment Division 1-8 that was inadvertently omitted in the Company's transmittal dated November 23, 2022. This transmittal completes the Company's responses in this matter.

Attachment Division 1-8 consists of a site plan that contains confidential critical energy infrastructure information. The Company is providing Attachment Division 1-8 to the Division pursuant to the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022. Also, the Company previously identified Attachment Division 1-38-2 as confidential in its transmittal dated December 2, 2022; however, the Company has since determined that this attachment is not confidential.

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: John Bell, Division (w/confidential attachment)
Al Mancini, Division (w/confidential attachment)
Leo Wold, Esq.

Division Set 1

Division 1-1

Request:

Discuss the Division and Commission administrative processes the Company envisions will take place in the following periods pursuant to R.I. Gen. Laws § 39-1-27.7.1 if the Proposed FY 2024 Gas ISR Plan were adopted by the Commission.

(a) CY 2023;

(b) CY 2024; and

(c) CY 2025.

Response:

Below is a summary of the Gas ISR plan filing timeline that Rhode Island Energy envisions will take place for calendar year ("CY") 2023, CY 2024, and CY 2025, assuming the Fiscal Year ("FY") 2024 (21-Month) Gas ISR Plan ("21-Month Plan") is approved by the Rhode Island Public Utilities Commission ("Commission").

(a) and (b)

Rhode Island Energy will file the 21-Month Plan with the Commission by December 22, 2022, with an anticipated approval in March 2023 and a rate effective date of April 1, 2023. The term of the 21-Month Plan would be for the 21-month period of April 1, 2023, through December 31, 2024.

The Company envisions submitting a reconciliation filing as soon as possible following the end of the 21-Month Plan for the 21-month period of April 1, 2023, through December 31, 2024, the timing of which may depend on, among other things, the Commission's regulatory calendar and when the data needed for the reconciliation filing, including tax information, is available.

(c) Rhode Island Energy will file the proposed FY 2025 Gas ISR Plan with the Division between April 1, 2024, and May 1, 2024. Using this timeline, the Company would file the FY 2025 Gas ISR Plan with the Commission on or around July 1, 2024, with an anticipated approval on or around October 1, 2024. The term of the plan would be for the twelve-month period from January 1, 2025, through December 31, 2025. Moving the procedural timeline forward may result in the FY 2025 Gas ISR Plan having less project specific information and more general work volumes.

Prepared by or under the supervision of: Nathan Kocon

Division 1-1, page 2

The Company envisions filing its reconciliation filing with the Commission as soon as possible following the end of the FY 2025 Gas ISR Plan, for the 12-month period of January 1, 2025, through December 31, 2025, the timing of which may depend on, among other things, the Commission's regulatory calendar and when the data needed for the reconciliation filing, including tax information, is available.

Prepared by or under the supervision of: Nathan Kocon

Division 1-2

Request:

On Page 7, [1] the Company states that "Through the Proactive Main Replacement Program the Company measures methane emissions reductions on a calendar year basis. From 2012 through 2021, the Company has reduced emissions from its gas distribution system by 92,918 MCF. In CY 2023 the Company plans to reduce emissions by 17,697 MCF and another 19,369 MCF in 2024."

(a) For each calendar the year (2012-2021) provide the methane reduction (MCF/yr) and calculations achieving the identified yearly reduction.

(b) If the Company's measurement methods have changed since 2012, please describe what those changes have been.

(c) Explain how the Company will achieve a 17,697 MCF reduction in CY 2023 through the program and provide the calculation.

(d) Explain how the Company will achieve a 19,369 MCF reduction in CY 2024 through the program and provide the calculation.

(e) Identify and discuss the methodologies for estimating leak quantities by pipe material.

Response:

(a) Please see the summary table below for the methane reduction (MCF/yr) and calculations achieving the identified yearly reduction.

[1] Page numbers refer to the Bates Stamp Page number contained in the lower right-hand corner of RIE's Proposed FY 2024 Gas ISR Plan dated October 21, 2022.

Division 1-2, page 2

Year	Emission (MCF)	Reduction (MCF)
2012	373,157	NA
2013	360,764	12,393
2014	349,053	11,711
2015	334,078	14,975
2016	323,068	11,010
2017	312,314	10,753
2018	302,482	9,832
2019	302,734	(252)[1]
2020	291,105	11,630
2021	280,239	10,866

Note 1: The negative reduction occurred due to a National Grid system change.

(b) There has been no change in the Company's methods for measuring methane emissions since 2012. The Company follows the Environmental Protection Agency's ("EPA") model for methane emissions calculations, at 40 CFR Part 98 Subpart W, Table W-7 for Petroleum and Natural Gas Systems, provided as Attachment Division 1-2. The EPA model is an industry accepted approach for measuring methane emissions reductions.

(c) & (d) The Company is planning to replace a total of 65 and 70 miles of leak prone pipe in CY 2023 & CY 2024, which results in the methane reduction as shown below. Please note that methane emissions reductions vary by material type.

Division 1-2, page 3

CY 2023		Miles/ Services	Resulting Methane Reduction (MCF)
Bare Steel/ Unprotected Coated Steel	Other Programs	4	
	Proactive	12	
	Total Bare Steel	**16**	
Cast Iron/ Wrought Iron/ Ducticle Iron	Other Programs	10	
	Proactive	39	
	Total Cast Iron	**49**	
Main Abandonment: Leak Prone Pipe	**Total Miles Main**	**65**	**12,784**
Services: Leak Prone Services replaced with Main Replacement*&**&***	**Total Services**	**2,967**	**4,913**
Total Methane Reduction			**17,697**

CY 2024		Miles/ Services	Resulting Methane Reduction (MCF)
Bare Steel/ Unprotected Coated Steel	Other Programs	3	
	Proactive	11	
	Total Bare Steel	**14**	
Cast Iron/ Wrought Iron/ Ducticle Iron	Other Programs	11	
	Proactive	45	
	Total Cast Iron	**56**	
Main Abandonment: Leak Prone Pipe	**Total Miles Main**	**70**	**14,116**
Services: Leak Prone Services replaced with Main Replacement*&**&***	**Total Services**	**2,967**	**5,253**
Total Methane Reduction			**19,369**

Assumptions:
*For each mile of LPP main replaced, there is an average of 83 services replaced per mile of main replacement
**On average, 55% of the services replaced were leak prone services
***Currently 99.8% of LPP services are Unprotected Steel; the model assumes 100% services are unprotected steel.

Prepared by or under the supervision of: Lee Gresham

(e) The EPA model of calculating methane emissions does not provide a way to estimate leak quantities by pipe material. The table below provides an emission rate by pipe material over time. (See 40 CFR Part 98 Subpart W, Table W-7 in Attachment Division 1-2)

MAINS	**Factor (scf/hour/mile)**	**Mcf/year/mile**
Cast Iron	27.25	238.71
Protected Steel	0.35	3.066
Unprotected Steel	12.58	110.201
Plastic	1.13	9.8988
SERVICES	**Factor (scf/hour/# of services)**	**Mcf/year/# of services**
Copper	0.03	0.2628
Protected Steel	0.02	0.1752
Unprotected Steel/CI	0.19	1.6644
Plastic	0.001	0.00876

Title 40 - Protection of Environment
Chapter I - Environmental Protection Agency
Subchapter C - Air Programs
Part 98 - Mandatory Greenhouse Gas Reporting

Authority: 42 U.S.C. 7401-7671q.

Source: 74 FR 56374, Oct. 30, 2009, unless otherwise noted.

Subpart W - Petroleum and Natural Gas Systems

Source: 75 FR 74488, Nov. 30, 2010, unless otherwise noted.

§ 98.230 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) ***Offshore petroleum and natural gas production.*** Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production

includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) ***Onshore petroleum and natural gas production.*** Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Onshore petroleum and natural gas production also means all equipment on or associated with a single enhanced oil recovery (EOR) well pad using CO_2 or natural gas injection.

(3) ***Onshore natural gas processing.*** Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

(4) ***Onshore natural gas transmission compression.*** Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

(5) ***Underground natural gas storage.*** Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) ***Liquefied natural gas (LNG) storage.*** LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) ***LNG import and export equipment.*** LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) ***Natural gas distribution.*** Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

(9) ***Onshore petroleum and natural gas gathering and boosting.*** Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).

(10) ***Onshore natural gas transmission pipeline.*** Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in § 98.238.

(b) [Reserved]

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011; 79 FR 70385, Nov. 25, 2014; 80 FR 64283, Oct. 22, 2015]

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of § 98.2(a)(2), except for the industry segments in paragraphs (a)(1) through (4) of this section.

(1) Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year.

(2) Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(3) Facilities must report emissions from the onshore petroleum and natural gas gathering and boosting industry segment only if emission sources specified in § 98.232(j) emit 25,000 metric tons of CO_2 equivalent or more per year.

(4) Facilities must report emissions from the onshore natural gas transmission pipeline industry segment only if emission sources specified in § 98.232(m) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in § 98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

[75 FR 74488, Nov. 30, 2010, as amended at 80 FR 64284, Oct. 22, 2015]

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a single well-pad or associated with a single well-pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Well venting during well completions with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Well venting during well workovers with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

(22) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in § 98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). The other components subject to this paragraph (e)(8) also do not include thief

hatches or other openings on a storage vessel. If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(f) For underground natural gas storage, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) Flare stack emissions.

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters associated with storage stations.

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(7) Equipment leaks from valves, connectors, open-ended lines, and pressure relief valves associated with storage wellheads.

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a, of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(g) For LNG storage, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Flare stack emissions.

(4) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(5) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (g)(6) of this section.

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(h) LNG import and export equipment, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Flare stack emissions.

(5) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(6) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (h)(7) of this section.

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(i) For natural gas distribution, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines at above grade transmission-distribution transfer stations.

(2) Equipment leaks at below grade transmission-distribution transfer stations.

(3) Equipment leaks at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(4) Equipment leaks at below grade metering-regulating stations.

(5) Distribution main equipment leaks.

(6) Distribution services equipment leaks.

(7) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z).

(j) For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Natural gas pneumatic device venting.

(2) Natural gas driven pneumatic pump venting.

(3) Acid gas removal vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Storage tank vented emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

(11) Gathering pipeline equipment leaks.

(12) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas gathering and boosting facility as defined in § 98.238. Stationary or portable equipment includes the following equipment, which are integral to the movement of natural gas: Natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011; 79 FR 70385, Nov. 25, 2014; 80 FR 64284, Oct. 22, 2015; 81 FR 86511, Nov. 30, 2016]

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For calculations that specify measurements in actual conditions, reporters may use a flow or volume measurement system that corrects to standard conditions and determine the flow or volume at standard conditions; otherwise, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) ***Natural gas pneumatic device venting.*** Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W-1 of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types “t” (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type “t” (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type “t” listed in Tables W-1A, W-3B, and W-4B to this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W-1A to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type “t”, were operational using engineering estimates based on best available data. Default is 8,760 hours.

(1) For all industry segments, determine “$Count_t$” for Equation W-1 of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the devices, except as specified in paragraph (a)(2) of this section. The reported number of devices must represent the total number of devices for the reporting year.

(2) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine “$Count_t$” for Equation W-1 of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two

consecutive calendar years to determine "$Count_t$" for Equation W-1 for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(b) [Reserved]

(c) ***Natural gas driven pneumatic pump venting.***

(1) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pump venting using Equation W-2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under this paragraph (c).

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-2)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps.

EF = Population emissions factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W-1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

T = Average estimated number of hours in the operating year the pumps were operational using engineering estimates based on best available data. Default is 8,760 hours.

(2) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(d) ***Acid gas removal (AGR) vents.*** For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through a flare, engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant, using any of the calculation methods described in this paragraph (d), as applicable.

(1) ***Calculation Method 1.*** If you operate and maintain a continuous emissions monitoring system (CEMS) that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and

volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Method in subpart C of this part (General Stationary Fuel Combustion Sources). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGR units.

(2) ***Calculation Method 2.*** If a CEMS is not available but a vent meter is installed, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.

$$E_{a,CO_2} = V_s * Vol_{CO_2} \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_{CO2} = Annual average volumetric fraction of CO_2 content in vent gas flowing out of the AGR unit as determined in paragraph (d)(6) of this section.

(3) ***Calculation Method 3.*** If a CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations W-4A or W-4B of this section. If inlet gas flow rate is known, use Equation W-4A. If outlet gas flow rate is known, use Equation W-4B.

$$E_{a,CO2} = V_{in} * \left[\frac{Vol_I - Vol_O}{1 - Vol_O} \right] \qquad \text{(Eq. W-4A)}$$

$$E_{a,CO2} = V_{out} * \left[\frac{Vol_I - Vol_O}{1 - Vol_I} \right] \qquad \text{(Eq. W-4B)}$$

Where:

$E_{a,\,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

Vol_I = Annual average volumetric fraction of CO_2 content in natural gas flowing into the AGR unit as determined in paragraph (d)(7) of this section.

> Vol_o = Annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) ***Calculation Method 4.*** If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CO_2 emissions. A minimum of the following, determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data, must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) For Calculation Method 3, determine the gas flow rate of the inlet when using Equation W-4A of this section or the gas flow rate of the outlet when using Equation W-4B of this section for the natural gas stream of an AGR unit using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) For Calculation Method 2, if a continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream for each quarter that the AGR unit is operating to determine Vol_{CO2} in Equation W-3 of this section, according to the methods set forth in § 98.234(b).

(7) For Calculation Method 3, if a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream for each quarter that the AGR unit is operating to determine Vol_I in Equation W-4A or W-4B of this section, according to the methods set forth in § 98.234(b).

(8) For Calculation Method 3, determine annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit using one of the methods specified in paragraphs (d)(8)(i) through (d)(8)(iii) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream for each quarter that the AGR unit is operating to determine Vol_O in Equation W-4A or W-4B of this section, according to the methods set forth in § 98.234(b).

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas.

(9) Calculate annual volumetric CO_2 emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Calculate annual mass CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if CO_2 emissions from the AGR unit are recovered and transferred outside the facility. Adjust the CO_2 emissions estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of CO_2 emissions recovered and transferred outside the facility.

(e) ***Dehydrator vents.*** For dehydrator vents, calculate annual CH_4 and CO_2 emissions using the applicable calculation methods described in paragraphs (e)(1) through (e)(4) of this section. If emissions from dehydrator vents are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (e)(5) of this section. If emissions from dehydrator vents are routed to a flare or regenerator fire-box/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(6) of this section.

(1) ***Calculation Method 1.*** Calculate annual mass emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day by using a software program, such as AspenTech HYSYS® or GRI-GLYCalc™, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. The following parameters must be determined by engineering estimate based on best available data and must be used at a minimum to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (*e.g.*, natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type (*e.g.*, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG)).

(vii) Use of stripping gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) through (D) of this section.

(A) Use the GHG mole fraction as defined in paragraph (u)(2)(i) or (ii) of this section.

(B) If the GHG mole fraction cannot be determined using paragraph (u)(2)(i) or (ii) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) ***Calculation Method 2.*** Calculate annual volumetric emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day using Equation W-5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

(3) ***Calculation Method 3.*** For dehydrators of any size that use desiccant, you must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W-6 of this section. Desiccant dehydrator emissions covered in this paragraph do not have to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

$$E_{s,n} = \frac{(H * D^2 * \pi * P_2 * \%G * N)}{(4 * P_1 * 100)} \qquad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

π = pi (3.14).

%G = Percent of packed vessel volume that is gas.

N = Number of dehydrator openings in the calendar year.

100 = Conversion of %G to fraction.

(4) For glycol dehydrators that use the calculation method in paragraph (e)(2) of this section, calculate both CH_4 and CO_2 mass emissions from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For desiccant dehydrators that use the calculation method in paragraph (e)(3) of this section, calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1), (2), and (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(6) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(i) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) through (5) of this section, as applicable.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(f) ***Well venting for liquids unloadings.*** Calculate annual volumetric natural gas emissions from well venting for liquids unloading using one of the calculation methods described in paragraphs (f)(1), (2), or (3) of this section. Calculate annual CH_4 and CO_2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section.

(1) ***Calculation Method 1.*** Calculate emissions from wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter on the vent line used to vent gas from the well (*e.g.,* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate the total emissions from well venting to the atmosphere for liquids unloading using Equation W-7A of this section. For any tubing diameter group and pressure group combination in a sub-basin where liquids unloading occurs both with and without plunger lifts, Equation W-7A will be used twice, once for wells with plunger lifts and once for wells without plunger lifts.

$$E_a = FR \sum_{p=1}^{h} T_p \qquad \text{(Eq. W-7A)}$$

Where:

E_a = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions, a, in cubic feet. Calculate emission from wells with plunger lifts and wells without plunger lifts separately.

h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin either with or without plunger lifts.

p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.

T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, T_p, using Equation W-7B of this section.

FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

$$T_p = \frac{HR_p}{MP_p} \text{ x } D_p \qquad \text{(Eq. W-7B)}$$

Where:

HR_p = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.

MP_p = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

D_p = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate (“FR” in Equation W-7A of this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with plunger lifts and wells without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) Calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) ***Calculation Method 2.*** Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W-8 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-8)}$$

Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period per well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p = Casing internal diameter for each well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p = For each well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for each well, you may determine the casing pressure by multiplying the tubing pressure of each well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(3) ***Calculation Method 3.*** Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-9)}$$

Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period for each well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet.

SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

(4) Calculate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) ***Well venting during completions and workovers with hydraulic fracturing.*** Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W-10A or Equation W-10B of this section. Equation W-10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and Equation W-10B applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W-10A, you must follow the procedures specified in paragraph (g)(1). If you elect to use Equation W-10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2

volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_{p,s} \times FRM_s \quad \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times PR_{s,p} \right] \right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2 \right] \right] \quad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b).

(1) If you elect to use Equation W-10A of this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section, or Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section, to determine the value of FRM_s and FRM_i. If you elect to use Equation W-10A of this section on oil wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) ***Calculation Method 1.*** You must use Equation W-12A of this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W-12B of this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in Equations W-12A and W-12B of this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b).

(ii) ***Calculation Method 2 (for gas wells).*** You must use Equation W-12A as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W-12B as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) also apply. When calculating the flowback rates for use in Equations W-12A and W-12B of this section based on well parameters, you must record the well flowing pressure immediately upstream (and immediately downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate the well flowback. The upstream pressure must be surface pressure and reservoir pressure cannot be assumed. The downstream pressure must be measured after the choke and atmospheric pressure cannot be assumed. Calculate flowback rate using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow. You must use best engineering estimates based on best available data along with Equation W-11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W-11C of this section is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic. Convert calculated FR_a values from actual conditions upstream of the restriction orifice to standard conditions ($FR_{s,p}$ and $FR_{i,p}$) for use in Equations W-12A and W-12B of this section using Equation W-33 in paragraph (t) of this section.

$$FR_a = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \quad \text{(Eq. W-11A)}$$

Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Pressure immediately upstream of the choke (psia).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

P_2 = Pressure immediately downstream of the choke (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR_a = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. W-11B)}$$

Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$R = {}^{P1}\!/_{P2} \quad \text{(Eq. W-11C)}$$

Where:

R = Pressure ratio.

P_1 = Pressure immediately upstream of the choke (psia).

P_2 = Pressure immediately downstream of the choke (psia).

(iii) For Equation W-10A of this section, calculate FRM_s using Equation W-12A of this section.

$$FRM_s = \frac{\sum_{p=1}^{N} FR_{s,p}}{\sum_{p=1}^{N} PR_{s,p}} \quad \text{(Eq. W-12A)}$$

Where:

FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W-33 in paragraph (t) of this section. You may not use flow volume as used in Equation W-10B of this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) For Equation W-10A of this section, calculate FRM_i using Equation W-12B of this section.

$$FRMi = \frac{\sum_{p=1}^{N} FR_{i,p}}{\sum_{p=1}^{N} PR_{s,p}} \quad \text{(Eq. W-12B)}$$

Where:

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/ pits.

$FR_{i,p}$ = Initial measured gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or initial calculated flow rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s), p, for each sub-basin and well type combination. Measured and calculated $FR_{i,p}$ values must be based on flow conditions at the beginning of the separation period and must be expressed at standard conditions.

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(v) For Equation W-10A of this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

(vi) For Equations W-12A and W-12B of this section, calculate new flowback rates for well completions and well workovers in each sub-basin and well type combination once every two years starting in the first calendar year of data collection.

(vii) For oil wells where the gas production rate is not metered and you elect to use Equation W-10A of this section, calculate the average gas production rate ($PR_{s,p}$) using Equation W-12C of this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

(i) Vertical or horizontal (directional drilling).

(ii) With flaring or without flaring.

(iii) Reduced emission completion/workover or not reduced emission completion/workover.

(iv) Oil well or gas well.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions from total natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(4) Calculate annual emissions from well venting during well completions and workovers from hydraulic fracturing where all or a portion of the gas is flared as specified in paragraphs (g)(4)(i) and (ii) of this section.

(i) Use the volumetric total natural gas emissions vented to the atmosphere during well completions and workovers as determined in paragraph (g) of this section to calculate volumetric and mass emissions using paragraphs (u) and (v) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to adjust emissions for the portion of gas flared during well completions and workovers using hydraulic fracturing. This adjustment to emissions from completions using flaring, versus completions without flaring, accounts for the conversion of CH_4 to CO_2 in the flare and for the formation on N_2O during flaring.

(h) ***Gas well venting during completions and workovers without hydraulic fracturing.*** Calculate annual volumetric natural gas emissions from each gas well venting during workovers without hydraulic fracturing using Equation W-13A of this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using Equation W-13B of this section. You must convert annual volumetric natural gas emissions to CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (h)(1) of this section. If emissions from gas well venting during completions and workovers without hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (h)(2) of this section.

$$E_{s,wo} = N_{wo} * EF_{wo} \qquad \text{(Eq. W-13A)}$$

$$E_{s,p} = \sum_{p=1}^{f} V_p * T_p \qquad \text{(Eq. W-13B)}$$

Where:

$E_{s,wo}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well workovers without hydraulic fracturing.

N_{wo} = Number of workovers per sub-basin category that do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. Use 3,114 standard cubic feet natural gas per well workover without hydraulic fracturing.

$E_{s,p}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well completions without hydraulic fracturing.

p = Well completions 1 through f in a sub-basin.

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

V_p = Average daily gas production rate in standard cubic feet per hour for each well, p, undergoing completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

> T_p = Time that gas is vented to either the atmosphere or a flare for each well, p, undergoing completion without hydraulic fracturing, in hours during the year.

(1) Calculate both CH_4 and CO_2 volumetric emissions from natural gas volumetric emissions using calculations in paragraph (u) of this section. Calculate both CH_4 and CO_2 mass emissions from volumetric emissions vented to atmosphere using calculations in paragraph (v) of this section.

(2) Calculate annual emissions of CH_4, CO_2, and N_2O from gas well venting to flares during well completions and workovers not involving hydraulic fracturing as specified in paragraphs (h)(2)(i) and (ii) of this section.

(i) Use the gas well venting volume and gas composition during well completions and workovers that are flared as determined using the methods specified in paragraphs (h) and (h)(1) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine emissions from the flare for gas well venting to a flare during completions and workovers without hydraulic fracturing.

(i) ***Blowdown vent stacks.*** Calculate CO_2 and CH_4 blowdown vent stack emissions from the depressurization of equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance as specified in either paragraph (i)(2) or (3) of this section. You may use the method in paragraph (i)(2) of this section for some blowdown vent stacks at your facility and the method in paragraph (i)(3) of this section for other blowdown vent stacks at your facility. Equipment with a unique physical volume of less than 50 cubic feet as determined in paragraph (i)(1) of this section are not subject to the requirements in paragraphs (i)(2) through (4) of this section. The requirements in this paragraph (i) do not apply to blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading.

(1) ***Method for calculating unique physical volumes.*** You must calculate each unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves, in cubic feet, by using engineering estimates based on best available data.

(2) ***Method for determining emissions from blowdown vent stacks according to equipment or event type.*** If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. For industry segments other than onshore natural gas transmission pipeline, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event. For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the following eight categories: Pipeline

integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

(i) Calculate the total annual natural gas emissions from each unique physical volume that is blown down using either Equation W-14A or W-14B of this section.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s Z_a} \right) - V * C \right) \quad \text{(Eq. W-14A)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume between isolation valves, in cubic feet, as calculated in paragraph (i)(1) of this section.

C = Purge factor is 1 if the unique physical volume is not purged, or 0 if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the temperature.

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the pressure.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

$$E_{s,n} = \sum_{p=1}^{N}\left[V_p\left(\frac{(459.67+T_s)(P_{a,b,p}-P_{a,e,p})}{(459.67+T_{a,p})P_s Z_a}\right)\right] \qquad \text{(Eq. W-14B)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V_p = Unique physical volume between isolation valves, in cubic feet, for each blowdown "p."

T_s = Temperature at standard conditions (60 °F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown "p".

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p".

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(ii) Except as allowed in paragraph (i)(2)(iii) of this section, calculate annual CH_4 and CO_2 volumetric and mass emissions from each unique physical volume that is blown down by using the annual natural gas emission value as calculated in either Equation W-14A or Equation W-14B of paragraph (i)(2)(i) of this section and the calculation method specified in paragraph (i)(4) of this section. Calculate the total annual CH_4 and CO_2 emissions for each equipment or event type by summing the annual CH_4 and CO_2 mass emissions for all unique physical volumes associated with the equipment or event type.

(iii) For onshore natural gas transmission compression facilities and LNG import and export equipment, as an alternative to using the procedures in paragraph (i)(2)(ii) of this section, you may elect to sum the annual natural gas emissions as calculated using either Equation W-14A or Equation W-14B of paragraph (i)(2)(i) of this section for all unique physical volumes associated with the equipment type or event type. Calculate the total annual CH_4 and CO_2 volumetric and mass emissions for each equipment type or event type using the sums of the total annual natural gas emissions for each equipment type and the calculation method specified in paragraph (i)(4) of this section.

(3) ***Method for determining emissions from blowdown vent stacks using a flow meter.*** In lieu of determining emissions from blowdown vent stacks as specified in paragraph (i)(2) of this section, you may use a flow meter and measure blowdown vent stack emissions for any unique physical volumes determined according to paragraph (i)(1) of this section to be greater than or equal to 50 cubic feet. If you choose to use this method, you must measure the natural gas emissions from the blowdown(s) through the monitored stack(s) using a flow meter according to methods in § 98.234(b), and calculate annual CH_4 and CO_2 volumetric and mass emissions measured by the meters according to paragraph (i)(4) of this section.

(4) ***Method for converting from natural gas emissions to GHG volumetric and mass emissions.*** Calculate both CH_4 and CO_2 volumetric and mass emissions using the methods specified in paragraphs (u) and (v) of this section.

(j) ***Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.*** Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) ***Calculation Method 1.*** Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator or non-separator equipment enters an atmospheric pressure storage tank. The following parameters must be determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

(i) Separator or non-separator equipment temperature.

(ii) Separator or non-separator equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator or non-separator equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) ***Calculation Method 2.*** Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) ***Flow to storage tank after passing through a separator.*** Assume that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(ii) ***Flow to storage tank direct from wells.*** Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production oil and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(B) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(iii) ***Flow to storage tank direct from non-separator equipment.*** Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment liquid and gas compositions are available through a previous analysis, select the latest available analysis that is representative of liquid and gas from non-separator equipment in the same county and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment liquid and gas compositions are not available, use default liquid and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) ***Calculation Method 3.*** Calculate CH_4 and CO_2 emissions using Equation W-15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(4) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(5) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W-16 of this section.

$$E_{s,i,o} = \left(CF_n * \frac{E_n}{8760} * T_n \right) \quad \text{(Eq. W-16)}$$

Where:

$E_{s,i,o}$ = Annual volumetric GHG emissions at standard conditions from each storage tank in cubic feet that resulted from the dump valve on the gas-liquid separator not closing properly.

E_n = Storage tank emissions as determined in paragraphs (j)(1), (j)(2) and, if applicable, (j)(4) of this section in standard cubic feet per year.

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_n = Correction factor for tank emissions for time period T_n is 2.87 for crude oil production. Correction factor for tank emissions for time period T_n is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

(7) Calculate both CH_4 and CO_2 mass emissions from natural gas volumetric emissions using calculations in paragraph (v) of this section.

(k) ***Transmission storage tanks.*** For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (k)(4) of this section. If emissions from compressor scrubber dump valve leakage are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (k)(5) of this section.

(1) Except as specified in paragraph (k)(1)(iv) of this section, you must monitor the tank vapor vent stack annually for emissions using one of the methods specified in paragraphs (k)(1)(i) through (iii) of this section.

(i) Use an optical gas imaging instrument according to methods set forth in § 98.234(a)(1).

(ii) Measure the tank vent directly using a flow meter or high volume sampler according to methods in § 98.234(b) or (d) for a duration of 5 minutes.

(iii) Measure the tank vent using a calibrated bag according to methods in § 98.234(c) for a duration of 5 minutes or until the bag is full, whichever is shorter.

(iv) You may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the optical gas imaging instrument or acoustic leak detection device detects a leak, then you must use one of the methods in either paragraph (k)(2)(i) or (ii) of this section.

(i) Use a flow meter, such as a turbine meter, calibrated bag, or high volume sampler to estimate tank vapor volumes from the vent stack according to methods set forth in § 98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (k)(1)(ii) or (iii) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(3) If a leaking dump valve is identified, the leak must be counted as having occurred since the beginning of the calendar year, or from the previous test that did not detect leaking in the same calendar year. If the leaking dump valve is fixed following leak detection, the leak duration will end upon being repaired. If a leaking dump valve is identified and not repaired, the leak must be counted as having occurred through the rest of the calendar year.

(4) Use the requirements specified in paragraphs (k)(4)(i) and (ii) of this section to quantify annual emissions.

(i) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(ii) Calculate CH_4 and CO_2 volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(5) Calculate annual emissions from storage tanks to flares as specified in paragraphs (k)(5)(i) and (ii) of this section.

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions sent to a flare.

(l) ***Well testing venting and flaring.*** Calculate CH_4 and CO_2 annual emissions from well testing venting as specified in paragraphs (l)(1) through (5) of this section. If emissions from well testing venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (l)(6) of this section.

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the procedures specified in paragraph (l)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W-17A (for oil wells) or Equation W-17B (for gas wells) of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17A)}$$

$$E_{a,n} = PR * D \quad \text{(Eq. W-17B)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Average annual flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the calendar year that the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing if emissions are routed to a flare as specified in paragraphs (l)(6)(i) and (ii) of this section.

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) ***Associated gas venting and flaring.*** Calculate CH_4 and CO_2 annual emissions from associated gas venting not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as specified in paragraphs (m)(1) through (4) of this section. If emissions from associated gas venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (m)(5) of this section.

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

(2) If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraphs (m)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W-18 of this section.

$$E_{s,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} \left[\left(GOR_{p,q} * V_{p,q} \right) - SG_{p,q} \right] \quad \text{(Eq. W-18)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting at standard conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year during time periods in which associated gas was vented or flared.

$SG_{p,q}$ = Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year during time periods in which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate emissions from associated natural gas if emissions are routed to a flare as specified in paragraphs (m)(5)(i) and (ii) of this section.

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) ***Flare stack emissions.*** Calculate CO_2, CH_4, and N_2O emissions from a flare stack as specified in paragraphs (n)(1) through (9) of this section.

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in paragraphs (n)(2)(i) through (iii) of this section.

(i) For onshore natural gas production and onshore petroleum and natural gas gathering and boosting, determine the GHG mole fraction using paragraph (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole fraction in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole fraction in feed natural gas liquid for all streams.

(iii) For any industry segment required to report to flare stack emissions under § 98.232, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W-19 and W-20 of this section.

$$E_{s,CH4} = V_s * X_{CH4} * \left[(1-\eta) * Z_L + Z_U\right] \qquad \text{(Eq. W-19)}$$

$$E_{s,CO2} = V_s * X_{CO2} + \sum_{j=1}^{5}\left(\eta * V_s * Y_j * R_j * Z_L\right) \qquad \text{(Eq. W-20)}$$

Where:

$E_{s,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare in standard cubic feet, during the year as determined in paragraph (n)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).

X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

Z_U = Fraction of the feed gas sent to an un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

Z_L = Fraction of the feed gas sent to a burning flare (equal to 1 − Z_U).

Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare as determined in paragraph (n)(1) of this section.

R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculation in paragraph (v) of this section.

(7) Calculate N_2O emissions from flare stacks using Equation W-40 in paragraph (z) of this section.

(8) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the flare, you must calculate only CO_2 emissions for the flare. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (7) of this section are not required.

(9) The flare emissions determined under this paragraph (n) must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) ***Centrifugal compressor venting.*** If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11).

(1) ***General requirements for conducting volumetric emission measurements.*** You must conduct volumetric emission measurements on each centrifugal compressor as specified in this paragraph. Compressor sources (as defined in § 98.238) without manifolded vents must use a measurement method specified in paragraph (o)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in § 98.238) must use a measurement method specified in paragraph (o)(1)(i), (ii), (iii), or (iv) of this section.

(i) Centrifugal compressor source as found measurements. Measure venting from each compressor according to either paragraph (o)(1)(i)(A) or (B) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraphs (o)(1)(i)(C) and (D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (o)(2)(i)(A) or (B) of this section and, if the compressor has wet seal oil degassing vents, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (o)(2)(i)(A), (B), or (C) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) You must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If three consecutive calendar years occur without measuring the compressor in not-operating-depressurized-mode, you must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at the next scheduled depressurized shutdown. The requirement specified in this paragraph does not apply if the compressor has blind flanges in place throughout the reporting year. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(D) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (o)(6)(ii) of this section.

(ii) Centrifugal compressor source continuous monitoring. Instead of measuring the compressor source according to paragraph (o)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (o)(3) of this section.

(iii) Manifolded centrifugal compressor source as found measurements. For a compressor source that is part of a manifolded group of compressor sources (as defined in § 98.238), instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (o)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (o)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) Manifolded centrifugal compressor source continuous monitoring. For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressor sources as specified in paragraph (o)(5) of this section.

(2) ***Methods for performing as found measurements from individual centrifugal compressor sources.*** If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, and the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(i) For blowdown valves on compressors in operating-mode and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (o)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer according to methods set forth in § 98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(D) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraph (o)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the methods.

(ii) For wet seal oil degassing vents in operating-mode, determine vapor volumes at standard conditions, using a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(3) ***Methods for continuous measurement from individual centrifugal compressor sources.*** If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (o)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (o)(3)(i) and (ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor source at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) ***Methods for performing as found measurements from manifolded groups of centrifugal compressor sources.*** If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (o)(4)(i) and (ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in § 98.234(b).

(B) Calibrated bagging according to methods set forth in § 98.234(c).

(C) A high volume sampler according to methods set forth § 98.234(d).

(D) An acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(E) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (o)(4)(ii)(D) of this section. If emissions are not detected using the methods in § 98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method.

(5) ***Methods for continuous measurement from manifolded groups of centrifugal compressor sources.*** If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (o)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) ***Method for calculating volumetric GHG emissions from as found measurements for individual centrifugal compressor sources.*** For compressor sources measured according to paragraph (o)(1)(i) of this section, you must calculate annual GHG emissions from the compressor sources as specified in paragraphs (o)(6)(i) through (iv) of this section.

(i) Using Equation W-21 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) and (B) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-21)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (o)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section that was measured for the reporting year.

(ii) Using Equation W-22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (o)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section that was not measured in the reporting year.

(iii) Using Equation W-23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section. These emission factors must be calculated annually and used in Equation W-22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-23)}$$

Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in Equation W-21 of this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section.

(iv) The reporter emission factor in Equation W-23 of this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) ***Method for calculating volumetric GHG emissions from continuous monitoring of individual centrifugal compressor sources.*** For compressor sources measured according to paragraph (o)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using Equation W-24A of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \qquad \text{(Eq. W-24A)}$$

Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) ***Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of centrifugal compressor sources.*** For manifolded groups of compressor sources measured according to paragraph (o)(1)(iii) of this section, you must calculate annual volumetric GHG emissions using Equation W-24B of this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(8) or paragraph (p)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \quad \text{(Eq. W-24B)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (o)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) ***Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of centrifugal compressor sources.*** For a manifolded group of compressor sources measured according to paragraph (o)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using Equation W-24C of this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(9) or paragraph (p)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \quad \text{(Eq. W-24C)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(10) ***Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.*** You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-25 of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from centrifugal compressor wet seals, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors that have wet seal oil degassing vents.

$EF_{i,s}$ = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(11) ***Method for converting from volumetric to mass emissions.*** You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(12) ***General requirements for calculating volumetric GHG emissions from centrifugal compressors routed to flares.*** You must calculate and report emissions from all centrifugal compressor sources that are routed to a flare as specified in paragraphs (o)(12)(i) through (iii) of this section.

(i) Paragraphs (o)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in § 98.236(o).

(p) ***Reciprocating compressor venting.*** If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11).

(1) ***General requirements for conducting volumetric emission measurements.*** You must conduct volumetric emission measurements on each reciprocating compressor as specified in this paragraph. Compressor sources (as defined in § 98.238) without manifolded vents must use a measurement method specified in paragraph (p)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in § 98.238) must use a measurement method specified in paragraph (p)(1)(i), (ii), (iii), or (iv) of this section.

(i) Reciprocating compressor source as found measurements. Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraphs (p)(1)(i)(D) and (E) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) of this section.

(B) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section.

(C) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (p)(2)(i)(A), (B), or (C) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(D) You must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If there is no scheduled shutdown within three consecutive calendar years, you must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at the next scheduled depressurized shutdown. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(E) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (p)(6)(ii) of this section.

(ii) Reciprocating compressor source continuous monitoring. Instead of measuring the compressor source according to paragraph (p)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (p)(3) of this section.

(iii) Manifolded reciprocating compressor source as found measurements. For a compressor source that is part of a manifolded group of compressor sources (as defined in § 98.238), instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (p)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (p)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) Manifolded reciprocating compressor source continuous monitoring. For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressors sources as specified in paragraph (p)(5) of this section.

(2) ***Methods for performing as found measurements from individual reciprocating compressor sources.*** If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section.

(i) For blowdown valves on compressors in operating-mode or standby-pressurized-mode, and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer, according to methods set forth in § 98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(D) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraphs (p)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method.

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(ii)(A) through (C) of this section.

(A) Determine the volumetric flow at standard conditions from the open-ended vent line using calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the open-ended vent line using a temporary meter such as a vane anemometer, according to methods set forth in § 98.234(b).

(C) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraph (p)(2)(ii)(A) and (p)(4)(ii)(B) of this section. If emissions are not detected using the methods in § 98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method.

(iii) For reciprocating rod packing not equipped with an open-ended vent line on compressors in operating-mode, you must determine the volumetric emissions using the method specified in paragraphs (p)(2)(iii)(A) and (B) of this section.

(A) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or for compressors with a closed distance piece, conduct annual detection of gas emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

(B) You must measure emissions found in paragraph (p)(2)(iii)(A) of this section using an appropriate meter, calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(3) ***Methods for continuous measurement from individual reciprocating compressor sources.*** If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (p)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (p)(3)(i) and (p)(3)(ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor sources at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) ***Methods for performing as found measurements from manifolded groups of reciprocating compressor sources.*** If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (p)(4)(i) and (ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraph (p)(4)(ii)(A) through (E) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in § 98.234(b).

(B) Calibrated bagging according to methods set forth in § 98.234(c).

(C) A high volume sampler according to methods set forth § 98.234(d).

(D) An acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(E) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraph (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method.

(5) ***Methods for continuous measurement from manifolded groups of reciprocating compressor sources.*** If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (p)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) ***Method for calculating volumetric GHG emissions from as found measurements for individual reciprocating compressor sources.*** For compressor sources measured according to paragraph (p)(1)(i) of this section, you must calculate GHG emissions from the compressor sources as specified in paragraphs (p)(6)(i) through (iv) of this section.

(i) Using Equation W-26 of this section, calculate the annual volumetric GHG emissions for each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (p)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using Equation W-27 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-27)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (p)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section that was not measured for the reporting year.

(iii) Using Equation W-28 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section. These emission factors must be calculated annually and used in Equation W-27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \quad \text{(Eq. W-28)}$$

Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in Equation W-26 of this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section.

(iv) The reporter emission factor in Equation W-28 of this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) ***Method for calculating volumetric GHG emissions from continuous monitoring of individual reciprocating compressor sources.*** For compressor sources measured according to paragraph (p)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using Equation W-29A of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \quad \text{(Eq. W-29A)}$$

Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) ***Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of reciprocating compressor sources.*** For manifolded groups of compressor sources measured according to paragraph (p)(1)(iii) of this section, you must calculate annual GHG emissions using Equation W-29B of this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(8) or paragraph (o)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \qquad \text{(Eq. W-29B)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (p)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) ***Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of reciprocating compressor sources.*** For a manifolded group of compressor sources measured according to paragraph (p)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using Equation W-29C of this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(9) or paragraph (o)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \qquad \text{(Eq. W-29C)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(10) ***Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.*** You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-29D of this section.

$$E_{s,i} = Count * EF_{i,s} \quad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(11) ***Method for converting from volumetric to mass emissions.*** You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(12) ***General requirements for calculating volumetric GHG emissions from reciprocating compressors routed to flares.*** You must calculate and report emissions from all reciprocating compressor sources that are routed to a flare as specified in paragraphs (p)(12)(i) through (iii) of this section.

(i) Paragraphs (p)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in § 98.236(p).

(q) ***Equipment leak surveys.*** For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported.

(1) ***Survey requirements.***

(i) For the components listed in § 98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods listed in § 98.234(a) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(ii) For the components listed in § 98.232(d)(7) and (i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a)(1) through (5) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iii) For the components listed in § 98.232(c)(21), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), and (j)(10) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(6) or (7) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iv) For the components listed in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), or (j)(10), that are not subject to fugitive emissions standards in § 60.5397a of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in § 98.234(a).

(A) If you elect to use a leak detection method in § 98.234(a)(1) through (5) for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) using the procedures in paragraph (q)(2) of this section.

(B) If you elect to use a leak detection method in § 98.234(a)(1) through (5) for the surveyed component types in § 98.232(e)(8), (f)(6), (f)(8), (g)(7), and (h)(8), then you must use the procedures in paragraph (q)(2) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(6) or (7) for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) using the emission calculation requirements in paragraph (q)(2) of this section.

(2) ***Emission calculation methodology.*** For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W-30 of this section and the requirements specified in paragraphs (q)(2)(i) through (xi) of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W-30 are used to calculate population emission factors on a meter/regulator run basis using Equation W-31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(2)(x)(A) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

$$E_{s,p,i} = GHG_i * EF_{s,p} * \sum_{z=1}^{x_p} T_{p,z} \quad \text{(Eq. W-30)}$$

Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHGi from specific component type "p" (in accordance with paragraphs (q)(1)(i) through (iv) of this section) in standard ("s") cubic feet, as specified in paragraphs (q)(2)(ii) through (x) of this section.

x_p = Total number of specific component type "p" detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor for specific component types listed in Tables W-1E, W-2, W-3A, W-4A, W-5A, W-6A, and W-7 to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

$T_{p,z}$ = The total time the surveyed component "z," component type "p," was assumed to be leaking and operational, in hours. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(i) You must conduct at least one leak detection survey in a calendar year. The leak detection surveys selected must be conducted during the calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using Equation W-30. For components subject to the well site and compressor station fugitive emissions standards in § 60.5397a of this chapter, each survey conducted in accordance with § 60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(ii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors for components in gas service, light crude service, and heavy crude service listed in Table W-1E to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas leaker factors for components in gas service listed in Table W-1E to this subpart.

(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W-2 to this subpart.

(vi) Onshore natural gas transmission compression facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W-3A to this subpart.

(vii) Underground natural gas storage facilities must use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in Table W-4A to this subpart.

(viii) LNG storage facilities must use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in Table W-5A to this subpart.

(ix) LNG import and export facilities must use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in Table W-6A to this subpart.

(x) Natural gas distribution facilities must use Equation W-30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W-7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations. Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section.

(A) Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years “n,” not exceeding a five year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(B) Use Equation W-31 of this section to determine the meter/regulator run population emission factors for each GHG_i. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHG_i annually according to paragraph (q)(2)(x)(C) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \quad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over “n” years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type “p” during year “y” in standard (“s”) cubic feet, as calculated using Equation W-30 of this section.

p = Seven component types listed in Table W-7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run “w” was operational, in hours during survey year “y” using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year “y”.

y = Year of data included in emission factor “$EF_{s,MR,i}$” according to paragraph (q)(2)(x)(C) of this section.

n = Number of years of data, according to paragraph (q)(2)(x)(A) of this section, whose results are used to calculate emission factor “$EF_{s,MR,i}$” according to paragraph (q)(2)(x)(C) of this section.

(C) The emission factor “$EFs_{MR,i,}$” based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, “n,” according to paragraph (q)(2)(x)(A) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor “$EF_{s,MR,i}$” from Equation W-31 of this section. After the first survey cycle of “n” years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year “y” and survey results from all previous (n−1) calendar years, such that each annual calculation of the emission factor “$EF_{s,MR,i}$” from Equation W-31 is based on survey results from “n” years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate “$EF_{s,MR,i}$” from Equation W-31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, "n_{new}," in the new cycle is smaller than the number of years in the previous cycle, "n," calculate "$EF_{s,MR,i}$" from Equation W-31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous (n_{new}−1) calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(2)(x)(A) of this section, you must use the meter/regulator run population emission factors calculated using Equation W-31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W-32B in paragraph (r) of this section.

(r) ***Equipment leaks by population count.*** This paragraph (r) applies to emissions sources listed in § 98.232(c)(21), (f)(7), (g)(5), (h)(6), and (j)(10) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in § 98.232(i)(2), (i)(3), (i)(4), (i)(5), (i)(6), and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W-32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W-32B of this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \qquad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \qquad \text{(Eq. W-32B)}$$

Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a component (*e.g.* connector, open-ended line, etc.), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W-1B and Table W-1C to this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W-1D to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W-4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W-7 to this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W-1A, W-4B, W-5B, W-6B, and W-7 to this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W-1D to this subpart.

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W-31 of this section.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, using engineering estimate based on best available data.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W-1A of this subpart. Major equipment and components associated with gas wells and onshore petroleum and natural gas gathering and boosting systems are considered gas service components in reference to Table W-1A of this subpart and major natural gas equipment in reference to Table W-1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W-1A of this subpart and major crude oil equipment in reference to Table W-1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W-1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using

either of the calculation methods described in this paragraph (r)(2), except for miles of gathering pipelines by material type, which must be determined using Component Count Method 2 in paragraph (r)(2)(ii) of this section. The same calculation method must be used for the entire calendar year.

(i) ***Component Count Method 1.*** For all onshore petroleum and natural gas production operations and onshore petroleum and natural gas gathering and boosting operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W-1B and Table W-1C of this subpart. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

(B) Multiply major equipment counts by the average component counts listed in Table W-1B of this subpart for onshore natural gas production and onshore petroleum and natural gas gathering and boosting; and Table W-1C of this subpart for onshore oil production. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(ii) ***Component Count Method 2.*** Count each component individually for the facility. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in Table W-4B to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factor for LNG storage compressors in gas service listed in Table W-5B to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factor for LNG terminal compressors in gas service listed in Table W-6B to this subpart.

(6) Natural gas distribution facilities must use the appropriate methane emission factors as described in paragraphs (r)(6)(i) and (ii) of this section.

(i) Below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in Table W-7 of this subpart. Below grade transmission-distribution transfer stations must use the emission factor for below grade metering-regulating stations.

(ii) Above grade metering-regulating stations that are not above grade transmission-distribution transfer stations must use the meter/regulator run population emission factor calculated in Equation W-31. Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in § 98.236(r)(2)(v).

(s) ***Offshore petroleum and natural gas production facilities.*** Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction must use the most recent monitoring methods and calculation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report annual emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, you may report the most recently reported emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle must use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report emissions.

(t) ***GHG volumetric emissions using actual conditions.*** If equation parameters in § 98.233 are already determined at standard conditions as provided in the introductory text in § 98.233, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation W-33 of this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet, except $E_{s,n}$ equals $FR_{s,p}$ for each well p when calculating either subsonic or sonic flowrates under § 98.233(g).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet, except $E_{a,n}$ equals $FR_{a,p}$ for each well p when calculating either subsonic or sonic flowrates under § 98.233(g).

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W-34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \quad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for GHG i.

You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) ***GHG volumetric emissions at standard conditions.*** Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W-35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W-35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) ***GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.*** If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) ***GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.*** You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(iv) ***GHG mole fraction in natural gas stored in the underground natural gas storage industry segment.*** You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) ***GHG mole fraction in natural gas stored in the LNG storage industry segment.*** You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vi) ***GHG mole fraction in natural gas stored in the LNG import and export industry segment.*** For export facilities that receive gas from transmission pipelines, you may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vii) ***GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.*** You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) ***GHG mass emissions.*** Calculate GHG mass emissions in metric tons by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W-36 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. W-36)}$$

Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

(w) ***EOR injection pump blowdown.*** Calculate CO_2 pump blowdown emissions from each EOR injection pump system as follows:

(1) Calculate the total injection pump system volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual CO_2 emissions from each EOR injection pump system using Equation W-37 of this section:

$$Mass_{CO2} = N * V_v * R_c * GHG_{CO2} * 10^{-3} \qquad \text{(Eq. W-37)}$$

Where:

$Mass_{CO2}$ = Annual EOR injection pump system emissions in metric tons from blowdowns.

N = Number of blowdowns for the EOR injection pump system in the calendar year.

V_v = Total volume in cubic feet of EOR injection pump system chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_{CO2} = Mass fraction of CO_2 in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) ***EOR hydrocarbon liquids dissolved CO_2*** . Calculate CO_2 emissions downstream of the storage tank from dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples of hydrocarbon liquids downstream of the storage tank must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W-38 of this section.

$$Mass_{CO2} = S_{hl} * V_{hl} \qquad \text{(Eq. W-38)}$$

Where:

$Mass_{CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) ***Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.*** Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraphs (z)(3) and (4) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to paragraph (z)(1)(i) of this section. If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation method described in paragraph (z)(1)(i) of this section and you may use the emission factor provided for natural gas as listed in Table C-1. If the fuel is natural gas, and is not pipeline quality or has a high heat value of less than 950 Btu per standard cubic feet, calculate emissions according to paragraph (z)(2) of this section. If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (z)(2) of this section.

(i) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities will be reported according to the requirements specified in § 98.236(z) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W-39A and W-39B of this section:

$$E_{a,CO2} = (V_a * Y_{CO2}) + \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH4} = V_a * (1-\eta) * Y_{CH4} \qquad \text{(Eq. W-39B)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 constituent in gas sent to combustion unit.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to combustion unit.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.

Y_{CH4} = Mole fraction of methane constituent in gas sent to combustion unit.

(iv) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(v) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(vi) Calculate N_2O mass emissions using Equation W-40 of this section.

$$Mass_{N2O} = \left(1 \times 10^{-3}\right) \times Fuel \times HHV \times EF \quad \text{(Eq. W-40)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value. For natural gas that is not of pipeline quality or that has a high heat value less than 950 Btu per standard cubic foot, use a site-specific higher heating value.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each internal fuel combustion unit.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80575, Dec. 23, 2011; 77 FR 51490, Aug. 24, 2012; 78 FR 71960, Nov. 29, 2013; 79 FR 70408, Nov. 25, 2014; 80 FR 64284, Oct. 22, 2015; 81 FR 86511, Nov. 30, 2016]

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of through-valve leakage from all source types listed in § 98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(i) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(ii) that occur during a calendar year. You must use one of the methods described in paragraph (a)(6) or (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii). If electing to comply with § 98.233(q) as specified in § 98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from component types as specified in § 98.233(q)(1)(iv) that occur during a calendar year.

(1) ***Optical gas imaging instrument as specified in § 60.18 of this chapter.*** Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the *Alternative work practice for monitoring equipment leaks,* § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels;* § 60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and § 60.18(i)(2)(iv) and (v); § 60.18(i)(3); § 60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) ***Method 21.*** Use the equipment leak detection methods in 40 CFR part 60, appendix A-7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) ***Infrared laser beam illuminated instrument.*** Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) ***Acoustic leak detection device.*** Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.

(6) Optical gas imaging instrument as specified in § 60.5397a of this chapter. Use an optical gas imaging instrument for equipment leak detection in accordance with § 60.5397a(b), (c)(3), (c)(7), and (e) of this chapter and paragraphs (a)(6)(i) through (iii) of this section. Unless using methods in paragraph (a)(7) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(i) For the purposes of this subpart, any visible emissions from a component listed in § 98.232 observed by the optical gas imaging instrument is a leak.

(ii) For the purposes of this subpart, the term "fugitive emissions component" in § 60.5397a of this chapter means "component."

(iii) For the purpose of complying with § 98.233(q)(1)(iv), the phrase "the collection of fugitive emissions components at well sites and compressor stations" in § 60.5397a(b) of this chapter means "the collection of components for which you elect to comply with § 98.233(q)(1)(iv)."

(7) Method 21 as specified in § 60.5397a of this chapter. Use the equipment leak detection methods in appendix A-7 to part 60 of this chapter, Method 21, in accordance with § 60.5397a(b), (c)(8), and (e) of this chapter and paragraphs (a)(7)(i) through (iii) of this section. Inaccessible emissions sources, as defined in part 60 of this chapter, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(6) of this section to monitor inaccessible equipment leaks.

(i) For the purposes of this subpart, any instrument reading from a component listed in § 98.232 of this chapter of 500 ppm or greater using Method 21 is a leak.

(ii) For the purposes of this subpart, the term "fugitive emissions component" in § 60.5397a of this chapter means "component."

(iii) For the purpose of complying with § 98.233(q)(1)(iv), the phrase "the collection of fugitive emissions components at well sites and compressor stations" in § 60.5397a(b) of this chapter means "the collection of components for which you elect to comply with § 98.233(q)(1)(iv)."

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methods relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W-41 of this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \text{(Eq. W-41)}$$

Where:

p = Absolute pressure.

R = Universal gas constant.

T = Absolute temperature.

V_m = Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 RT_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

(f) ***Special reporting provisions for best available monitoring methods in reporting year 2015*** -

(1) ***Best available monitoring methods.*** From January 1, 2015 to March 31, 2015, for a facility subject to this subpart, you must use the calculation methodologies and equations in § 98.233 "Calculating GHG Emissions", but you may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2015 as specified in paragraphs (f)(2) and (3) of this section. Starting no later than April 1, 2015, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (f)(4) of this section. Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) ***Best available monitoring methods for well-related measurement data.*** You may use best available monitoring methods for well-related measurement data identified in paragraphs (f)(2)(i) and (ii) of this section that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart.

(i) If Calculation Method 1 for liquids unloading in § 98.233(f)(1) was used in calendar year 2014 and will be used again in calendar year 2015, the vented natural gas flow rate for any well in a unique tubing diameter group and pressure group combination that has not been previously measured.

(ii) If using Equation W-10A of this subpart to determine natural gas emissions from completions and workovers for representative wells, the initial and average flowback rates (when using Calculation Method 1 in § 98.233(g)(1)(i)) or pressures upstream and downstream of the choke (when using Calculation Method 2 in § 98.233(g)(1)(ii)) for any well in a well type combination that has not been previously measured.

(3) ***Best available monitoring methods for emissions measurement.*** You may use best available monitoring methods for sources listed in paragraphs (f)(3)(i) and (ii) of this section if the required measurement data cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part.

(i) Centrifugal compressor as found measurements of manifolded emissions from groups of centrifugal compressor sources according to § 98.233(o)(4) and (5), in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(ii) Reciprocating compressor as found measurements of manifolded emissions from groups of reciprocating compressor sources according to § 98.233(p)(4) and (5), in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(4) ***Requests for extension of the use of best available monitoring methods beyond March 31, 2015.*** You may submit a request to the Administrator to use one or more best available monitoring methods for sources listed in paragraphs (f)(2) and (3) of this section beyond March 31, 2015.

(i) ***Timing of request.*** The extension request must be submitted to EPA no later than January 31, 2015.

(ii) ***Content of request.*** Requests must contain the following information:

(A) A list of specific source types and parameters for which you are seeking use of best available monitoring methods.

(B) For each specific source type for which you are requesting use of best available monitoring methods, a description of the reasons that the needed equipment could not be obtained and installed before April 1, 2015.

(C) A description of the specific actions you will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) ***Approval criteria.*** To obtain approval to use best available monitoring methods after March 31, 2015, you must submit a request demonstrating to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2015. The use of best available methods under paragraph (f) of this section will not be approved beyond December 31, 2015.

(g) ***Special reporting provisions for best available monitoring methods in reporting year 2016*** -

(1) ***Best available monitoring methods.*** From January 1, 2016, to December 31, 2016, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method as described in paragraph (g)(2) of this section for any parameter specified in paragraphs (g)(3) through (6) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016. Starting no later than January 1, 2017, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part. For onshore petroleum and natural gas production, this paragraph (g)(1) only applies if emissions from well completions and workovers of oil wells with hydraulic fracturing cause your facility to exceed the reporting threshold in § 98.231(a)(1).

(2) Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(3) ***Best available monitoring methods for well-related measurement data for oil wells with hydraulic fracturing.*** You may use best available monitoring methods for any well-related measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for venting during well completions and workovers of oil wells with hydraulic fracturing.

(4) ***Best available monitoring methods for measurement data for onshore petroleum and natural gas gathering and boosting facilities.*** You may use best available monitoring methods for any leak detection and/or measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in § 98.233(d).

(5) ***Best available monitoring methods for measurement data for natural gas transmission pipelines.*** You may use best available monitoring methods for any measurement data for natural gas transmission pipelines that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for blowdown vent stacks.

(6) ***Best available monitoring methods for specified activity data.*** You may use best available monitoring methods for activity data as listed in paragraphs (g)(6)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for well completions and workovers of oil wells with hydraulic fracturing, onshore petroleum and natural gas gathering and boosting facilities, or natural gas transmission pipelines.

(i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (g), (o), (p), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in § 98.233(g) and (i).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (n), and (z).

(h) For well venting for liquids unloading, if a monitoring period other than the full calendar year is used to determine the cumulative amount of time in hours of venting for each well (the term "T_p" in Equation W-7A and W-7B of § 98.233) or the number of unloading events per well (the term "V_p" in Equations W-8 and W-9 of § 98.233), then the monitoring period must begin before February 1 of the reporting year and must not end before December 1 of the reporting year. The end of one monitoring period must immediately precede the start of the next monitoring period for the next reporting year. All production days must be monitored and all venting accounted for.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 22827, Apr. 25, 2011; 76 FR 59540, Sept. 27, 2011; 76 FR 80586, Dec. 23, 2011; 78 FR 25395, May 1, 2013; 79 FR 70410, Nov. 25, 2014; 80 FR 64291, Oct. 22, 2015; 81 FR 86514, Nov. 30, 2016]

§ 98.235 Procedures for estimating missing data.

Except as specified in § 98.233, whenever a value of a parameter is unavailable for a GHG emission calculation required by this subpart (including, but not limited to, if a measuring device malfunctions during unit operation or activity data are not collected), you must follow the procedures specified in paragraphs (a) through (i) of this section, as applicable.

(a) For stationary and portable combustion sources that use the calculation methods of subpart C of this part, you must use the missing data procedures in subpart C of this part.

(b) For each missing value of a parameter that should have been measured quarterly or more frequently using equipment including, but not limited to, a continuous flow meter, composition analyzer, thermocouple, or pressure gauge, you must substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value is not obtained by the end of the reporting year, you may use the “before” value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, you must use the first quality-assured value obtained after the missing data period as the substitute data value. A value is quality-assured according to the procedures specified in § 98.234.

(c) For each missing value of a parameter that should have been measured annually, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection.

(d) For each missing value of a parameter that should have been measured biannually (every two years), you must conduct the estimation or measurement activity for those sources as soon as possible in the subsequent calendar year if the estimation or measurement was not made in the appropriate year (first year of data collection and every two years thereafter), until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used to alternate or postpone subsequent biannual emissions estimations or measurements.

(e) For the first 6 months of required data collection, facilities that become newly subject to this subpart W may use best engineering estimates for any data that cannot reasonably be measured or obtained according to the requirements of this subpart.

(f) For the first 6 months of required data collection, facilities that are currently subject to this subpart W and that acquire new sources from another facility that were not previously subject to this subpart W may use best engineering estimates for any data related to those newly acquired sources that cannot reasonably be measured or obtained according to the requirements of this subpart.

(g) Unless addressed in another paragraph of this section, for each missing value of any activity data, you must substitute data value(s) using the best available estimate(s) of the parameter(s), based on all applicable and available process or other data (including, but not limited to, processing rates, operating hours).

(h) You must report information for all measured and substitute values of a parameter, and the procedures used to substitute an unavailable value of a parameter per the requirements in § 98.236(bb).

(i) You must follow recordkeeping requirements listed in § 98.237(f).

[79 FR 70410, Nov. 25, 2014]

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in § 98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure.

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10), and each applicable emission source listed in paragraphs (b) through (z) of this section.

(1) ***Onshore petroleum and natural gas production.*** For the equipment/activities specified in paragraphs (a)(1)(i) through (xvii) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Natural gas pneumatic devices.*** Report the information specified in paragraph (b) of this section.

(ii) ***Natural gas driven pneumatic pumps.*** Report the information specified in paragraph (c) of this section.

(iii) ***Acid gas removal units.*** Report the information specified in paragraph (d) of this section.

(iv) ***Dehydrators.*** Report the information specified in paragraph (e) of this section.

(v) ***Liquids unloading.*** Report the information specified in paragraph (f) of this section.

(vi) ***Completions and workovers with hydraulic fracturing.*** Report the information specified in paragraph (g) of this section.

(vii) ***Completions and workovers without hydraulic fracturing.*** Report the information specified in paragraph (h) of this section.

(viii) ***Onshore production storage tanks.*** Report the information specified in paragraph (j) of this section.

(ix) ***Well testing.*** Report the information specified in paragraph (l) of this section.

(x) ***Associated natural gas.*** Report the information specified in paragraph (m) of this section.

(xi) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(xii) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(xiii) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(xiv) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(xv) ***Equipment leaks by population count.*** Report the information specified in paragraph (r) of this section.

(xvi) ***EOR injection pumps.*** Report the information specified in paragraph (w) of this section.

(xvii) ***EOR hydrocarbon liquids.*** Report the information specified in paragraph (x) of this section.

(xviii) ***Combustion equipment.*** Report the information specified in paragraph (z) of this section.

(2) ***Offshore petroleum and natural gas production.*** Report the information specified in paragraph (s) of this section.

(3) ***Onshore natural gas processing.*** For the equipment/activities specified in paragraphs (a)(3)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Acid gas removal units.*** Report the information specified in paragraph (d) of this section.

(ii) ***Dehydrators.*** Report the information specified in paragraph (e) of this section.

(iii) ***Blowdown vent stacks.*** Report the information specified in paragraph (i) of this section.

(iv) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(v) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(vi) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(vii) ***Equipment leak surveys.*** Report the information specified in paragraph (q) of this section.

(4) ***Onshore natural gas transmission compression.*** For the equipment/activities specified in paragraphs (a)(4)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Natural gas pneumatic devices.*** Report the information specified in paragraph (b) of this section.

(ii) ***Blowdown vent stacks.*** Report the information specified in paragraph (i) of this section.

(iii) ***Transmission storage tanks.*** Report the information specified in paragraph (k) of this section.

(iv) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(v) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(vi) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(vii) ***Equipment leak surveys.*** Report the information specified in paragraph (q) of this section.

(5) ***Underground natural gas storage.*** For the equipment/activities specified in paragraphs (a)(5)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Natural gas pneumatic devices.*** Report the information specified in paragraph (b) of this section.

(ii) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(iii) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(iv) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(v) ***Equipment leak surveys.*** Report the information specified in paragraph (q) of this section.

(vi) ***Equipment leaks by population count.*** Report the information specified in paragraph (r) of this section.

(6) ***LNG storage.*** For the equipment/activities specified in paragraphs (a)(6)(i) through (v) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(ii) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(iii) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(iv) ***Equipment leak surveys.*** Report the information specified in paragraph (q) of this section.

(v) ***Equipment leaks by population count.*** Report the information specified in paragraph (r) of this section.

(7) ***LNG import and export equipment.*** For the equipment/activities specified in paragraphs (a)(7)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Blowdown vent stacks.*** Report the information specified in paragraph (i) of this section.

(ii) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(iii) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(iv) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(v) ***Equipment leak surveys.*** Report the information specified in paragraph (q) of this section.

(vi) ***Equipment leaks by population count.*** Report the information specified in paragraph (r) of this section.

(8) ***Natural gas distribution.*** For the equipment/activities specified in paragraphs (a)(8)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Combustion equipment.*** Report the information specified in paragraph (z) of this section.

(ii) ***Equipment leak surveys.*** Report the information specified in paragraph (q) of this section.

(iii) ***Equipment leaks by population count.*** Report the information specified in paragraph (r) of this section.

(9) ***Onshore petroleum and natural gas gathering and boosting.*** For the equipment/activities specified in paragraphs (a)(9)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) ***Natural gas pneumatic devices.*** Report the information specified in paragraph (b) of this section.

(ii) ***Natural gas driven pneumatic pumps.*** Report the information specified in paragraph (c) of this section.

(iii) ***Acid gas removal units.*** Report the information specified in paragraph (d) of this section.

(iv) ***Dehydrators.*** Report the information specified in paragraph (e) of this section.

(v) ***Blowdown vent stacks.*** Report the information specified in paragraph (i) of this section.

(vi) ***Storage tanks.*** Report the information specified in paragraph (j) of this section.

(vii) ***Flare stacks.*** Report the information specified in paragraph (n) of this section.

(viii) ***Centrifugal compressors.*** Report the information specified in paragraph (o) of this section.

(ix) ***Reciprocating compressors.*** Report the information specified in paragraph (p) of this section.

(x) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(xi) ***Equipment leaks by population count.*** Report the information specified in paragraph (r) of this section.

(xii) ***Combustion equipment.*** Report the information specified in paragraph (z) of this section.

(10) ***Onshore natural gas transmission pipeline.*** For blowdown vent stacks, report the information specified in paragraph (i) of this section.

(b) ***Natural gas pneumatic devices.*** You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (b)(4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) The total number of devices of each type, determined according to § 98.233(a)(1) and (2).

(ii) If the reported value in paragraph (b)(1)(i) of this section is an estimated value determined according to § 98.233(a)(2), then you must report the information specified in paragraphs (b)(1)(ii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are counted.

(B) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device, the estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) of this section were operating in the calendar year ("T_t" in Equation W-1 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and § 98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(4) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and § 98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(c) ***Natural gas driven pneumatic pumps.*** You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (4) of this section.

(1) Count of natural gas driven pneumatic pumps.

(2) Average estimated number of hours in the calendar year the pumps were operational ("T" in Equation W-2 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps combined, calculated according to § 98.233(c)(1) and (2).

(4) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps combined, calculated according to § 98.233(c)(1) and (2).

(d) ***Acid gas removal units.*** You must indicate whether your facility has any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. If your facility contains any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant, then you must report the information specified in paragraphs (d)(1) and (2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (vi) of this section for each acid gas removal unit.

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

(ii) Total feed rate entering the acid gas removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million cubic feet per year.

(iii) The calculation method used to calculate CO_2 emissions from the acid gas removal unit, as specified in § 98.233(d).

(iv) Whether any CO_2 emissions from the acid gas removal unit are recovered and transferred outside the facility, as specified in § 98.233(d)(11). If any CO_2 emissions from the acid gas removal unit were recovered and transferred outside the facility, then you must report the annual quantity of CO_2, in metric tons CO_2, that was recovered and transferred outside the facility under subpart PP of this part.

(v) Annual CO_2 emissions, in metric tons CO_2, from the acid gas removal unit, calculated using any one of the calculation methods specified in § 98.233(d) and as specified in § 98.233(d)(10) and (11).

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the unit (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (iii) of this section, applicable to the calculation method reported in paragraph (d)(1)(iii) of this section, for each acid gas removal unit.

(i) If you used Calculation Method 1 or Calculation Method 2 as specified in § 98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) and (B) of this section.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual volume of gas vented from the acid gas removal unit, in cubic feet.

(ii) If you used Calculation Method 3 as specified in § 98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (D) of this section.

(A) Indicate which equation was used (Equation W-4A or W-4B).

(B) Annual average volumetric fraction of CO_2 in the natural gas flowing out of the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(C) Annual average volumetric fraction of CO_2 content in natural gas flowing into the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(D) The natural gas flow rate used, as specified in Equation W-4A of this subpart, reported as either total annual volume of natural gas flow into the acid gas removal unit in cubic feet at actual conditions; or total annual volume of natural gas flow out of the acid gas removal unit, as specified in Equation W-4B of this subpart, in cubic feet at actual conditions.

(iii) If you used Calculation Method 4 as specified in § 98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (L) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Natural gas feed temperature, in degrees Fahrenheit.

(C) Natural gas feed pressure, in pounds per square inch.

(D) Natural gas flow rate, in standard cubic feet per minute.

(E) Acid gas content of the feed natural gas, in mole percent.

(F) Acid gas content of the outlet natural gas, in mole percent.

(G) Unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(H) Exit temperature of the natural gas, in degrees Fahrenheit.

(I) Solvent pressure, in pounds per square inch.

(J) Solvent temperature, in degrees Fahrenheit.

(K) Solvent circulation rate, in gallons per minute.

(L) Solvent weight, in pounds per gallon.

(e) ***Dehydrators.*** You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day, glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day, and dehydrators that use desiccant. If your facility contains any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3).

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

(ii) Dehydrator feed natural gas flow rate, in million standard cubic feet per day, determined by engineering estimate based on best available data.

(iii) Dehydrator feed natural gas water content, in pounds per million standard cubic feet.

(iv) Dehydrator outlet natural gas water content, in pounds per million standard cubic feet.

(v) Dehydrator absorbent circulation pump type (*e.g.,* natural gas pneumatic, air pneumatic, or electric).

(vi) Dehydrator absorbent circulation rate, in gallons per minute.

(vii) Type of absorbent (*e.g.,* triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG)).

(viii) Whether stripper gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating, in hours.

(xi) Temperature of the wet natural gas, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas, in pounds per square inch gauge.

(xiii) Mole fraction of CH_4 in wet natural gas.

(xiv) Mole fraction of CO_2 in wet natural gas.

(xv) Whether any dehydrator emissions are vented to a vapor recovery device.

(xvi) Whether any dehydrator emissions are vented to a flare or regenerator firebox/fire tubes. If any emissions are vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(1)(xvi)(A) through (C) of this section for these emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator, calculated according to § 98.233(e)(6).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator, calculated according to § 98.233(e)(6).

(C) Annual N_2O emissions, in metric tons N_2O, for the dehydrator, calculated according to § 98.233(e)(6).

(xvii) Whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox/fire tubes. If any emissions are not routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(1)(xvii)(A) and (B) of this section for those emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1), and, if applicable, (e)(5).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(5).

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day (as specified in § 98.233(e)(2)), you must report the information specified in paragraphs (e)(2)(i) through (v) of this section for the entire facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrator emissions were vented to a vapor recovery device. If any dehydrator emissions were vented to a vapor recovery device, then you must report the total number of dehydrators at the facility that vented to a vapor recovery device.

(iii) Whether any dehydrator emissions were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a control device(s) other than a vapor recovery device or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were vented to each type of control device.

(iv) Whether any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (D) of this section.

(A) The total number of dehydrators venting to a flare or regenerator firebox/fire tubes.

(B) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(6).

(C) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(6).

(D) Annual N_2O emissions, in metric tons N_2O, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(6).

(v) For dehydrator emissions that were not vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(3) For dehydrators that use desiccant (as specified in § 98.233(e)(3)), you must report the information specified in paragraphs (e)(3)(i) through (iii) of this section for the entire facility.

(i) The same information specified in paragraphs (e)(2)(i) through (iv) of this section for glycol dehydrators, and report the information under this paragraph for dehydrators that use desiccant.

(ii) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(iii) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(f) ***Liquids unloading.*** You must indicate whether well venting for liquids unloading occurs at your facility, and if so, which methods (as specified in § 98.233(f)) were used to calculate emissions. If your facility performs well venting for liquids unloading and uses Calculation Method 1, then you must report the information specified in paragraph (f)(1) of this section. If the facility performs liquids unloading and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells with plunger lifts and wells without plunger lifts.

(i) Sub-basin ID.

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin and well tubing diameter and pressure group ID.

(iii) Plunger lift indicator.

(iv) Count of wells vented to the atmosphere for the sub-basin/well tubing diameter and pressure group.

(v) Percentage of wells for which the monitoring period used to determine the cumulative amount of time venting was not the full calendar year.

(vi) Cumulative amount of time wells were vented (sum of "T_p" from Equation W-7A or W-7B of this subpart), in hours.

(vii) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells in the sub-basin/well tubing diameter and pressure group.

(viii) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to § 98.233(f)(1).

(ix) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to § 98.233(f)(1) and (4).

(x) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to § 98.233(f)(1) and (4).

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (E) of this section for each individual well not using a plunger lift that was tested during the year.

(A) Well ID number of tested well.

(B) Casing pressure, in pounds per square inch absolute.

(C) Internal casing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (E) of this section for each individual well using a plunger lift that was tested during the year.

(A) Well ID number.

(B) The tubing pressure, in pounds per square inch absolute.

(C) The internal tubing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in § 93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in (f)(2)(i) through (x) of this section. Report information separately for each calculation method.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin.

(ii) Calculation method.

(iii) Plunger lift indicator.

(iv) Number of wells vented to the atmosphere.

(v) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells.

(vi) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to § 98.233(f)(2) or (3), as applicable.

(vii) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to § 98.233(f)(2) or (3), as applicable, and § 98.233(f)(4).

(viii) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to § 98.233(f)(2) or (3), as applicable, and § 98.233(f)(4).

(ix) For wells without plunger lifts, the average internal casing diameter, in inches.

(x) For wells with plunger lifts, the average internal tubing diameter, in inches.

(g) ***Completions and workovers with hydraulic fracturing.*** You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.

(1) Sub-basin ID and a list of the well ID numbers associated with each sub-basin that had completions or workovers with hydraulic fracturing during the calendar year.

(2) Well type combination (horizontal or vertical, gas well or oil well).

(3) Number of completions or workovers in the sub-basin and well type combination category.

(4) Calculation method used.

(5) If you used Equation W-10A of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of "$T_{p,i}$" and sum of "$T_{p,s}$" values used in Equation W-10A of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per hour (average of "$FR_{s,p}$" values used in Equation W-12A of § 98.233), and the well ID numbers of the wells for which it is measured. You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured flowback rate during well completion or workover and the well ID number(s) for the well(s) included in the measurement.

(iii) If you used Equation W-12C of § 98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil ("GOR_p" in Equation W-12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the gas to oil ratio for the well and the well ID number for the well.

(B) Volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels ("V_p" in Equation W-12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced during the first 30 days of production after well completion or workover and the well ID number for the well.

(6) If you used Equation W-10B of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin ("$FV_{s,p}$" in Equation W-10B of § 98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin ("$FR_{p,i}$" in Equation W-10B of § 98.233).

(iii) The well ID number for which vented natural gas volume was measured.

(7) Annual gas emissions, in standard cubic feet ("$E_{s,n}$" in Equation W-10A or W-10B).

(8) Annual CO_2 emissions, in metric tons CO_2.

(9) Annual CH_4 emissions, in metric tons CH_4.

(10) If the well emissions were vented to a flare, then you must report the total N_2O emissions, in metric tons N_2O.

(h) ***Completions and workovers without hydraulic fracturing.*** You must indicate whether the facility had any gas well completions without hydraulic fracturing or any gas well workovers without hydraulic fracturing, and if the activities occurred with or without flaring. If the facility had gas well completions or workovers without hydraulic fracturing, then you must report the information specified in paragraphs (h)(1) through (4) of this section, as applicable.

(1) For each sub-basin with gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and without flaring.

(ii) Number of well completions that vented gas directly to the atmosphere without flaring.

(iii) Total number of hours that gas vented directly to the atmosphere during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to the atmosphere as used in Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all "V_p" used in Equation W-13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions venting gas directly to the atmosphere ("$E_{s,p}$" from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to § 98.233(h)(1)).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions venting gas directly to the atmosphere ("$E_{s,p}$" from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to § 98.233(h)(1)).

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (vii) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and with flaring.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas vented to a flare during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to a flare from Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all "V_p" from Equation W-13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(vii) Annual N_2O emissions, in metric tons N_2O, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(3) For each sub-basin with gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and without flaring.

(ii) Number of workovers that vented gas to the atmosphere without flaring.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers venting gas directly to the atmosphere ("$E_{s,wo}$" in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in § 98.233(h)(1)).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers venting gas directly to the atmosphere ("$E_{s,wo}$" in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in § 98.233(h)(1)).

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (v) of this section.

(i) Sub-basin ID and a list of well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and with flaring.

(ii) Number of workovers that flared gas.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers that flared gas, calculated as specified in § 98.233(h)(2).

(v) Annual N_2O emissions, in metric tons N_2O per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(i) ***Blowdown vent stacks.*** You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section.

(1) ***Report by equipment or event type.*** If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2) for industry segments other than the onshore natural gas transmission pipeline segment, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each "equipment or event type" (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the "equipment or event type" (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

(i) Total number of blowdowns in the calendar year for the equipment or event type (the sum of equation variable "N" from Equation W-14A or Equation W-14B of this subpart, for all unique physical volumes for the equipment or event type).

(ii) Annual CO_2 emissions for the equipment or event type, in metric tons CO_2, calculated according to § 98.233(i)(2)(iii).

(iii) Annual CH_4 emissions for the equipment or event type, in metric tons CH_4, calculated according to § 98.233(i)(2)(iii).

(2) ***Report by flow meter.*** If you elect to calculate emissions from blowdown vent stacks by using a flow meter according to § 98.233(i)(3), then you must report the information specified in paragraphs (i)(2)(i) and (ii) of this section for the facility.

(i) Annual CO_2 emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CO_2 (the sum of all CO_2 mass emission values calculated according to § 98.233(i)(3), for all flow meters).

(ii) Annual CH_4 emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CH_4, (the sum of all CH_4 mass emission values calculated according to § 98.233(i)(3), for all flow meters).

(3) ***Onshore natural gas transmission pipeline segment.*** Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) ***Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.*** You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraphs (j)(1)(ix) and (xi) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual oil volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized oil API gravity, in degrees.

(vii) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(ix) The number of wells sending oil to gas-liquid separators or directly to atmospheric tanks.

(x) The number of atmospheric tanks.

(xi) An estimate of the number of atmospheric tanks, not on well-pads, receiving your oil.

(xii) If any emissions from the atmospheric tanks at your facility were controlled with vapor recovery systems, then you must report the information specified in paragraphs (j)(1)(xii)(A) through (E) of this section.

(A) The number of atmospheric tanks that control emissions with vapor recovery systems.

(B) Total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(C) Total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(D) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks equipped with vapor recovery systems.

(E) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks equipped with vapor recovery systems.

(xiii) If any atmospheric tanks at your facility vented gas directly to the atmosphere without using a vapor recovery system or without flaring, then you must report the information specified in paragraphs (j)(1)(xiii)(A) through (C) of this section.

(A) The number of atmospheric tanks that vented gas directly to the atmosphere without using a vapor recovery system or without flaring.

(B) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere.

(C) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere.

(xiv) If you controlled emissions from any atmospheric tanks at your facility with one or more flares, then you must report the information specified in paragraphs (j)(1)(xiv)(A) through (D) of this section.

(A) The number of atmospheric tanks that controlled emissions with flares.

(B) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with one or more flares.

(C) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with one or more flares.

(D) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with one or more flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of § 98.233(j). Onshore gathering and boosting facilities do not report the information specified in paragraphs (j)(2)(i)(E) and (F) of this section.

(A) The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil/condensate production less than 10 barrels per day and that send oil/condensate to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual oil/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The number of wells with gas-liquid separators (“Count” from Equation W-15 of this subpart) in the basin.

(F) The number of wells without gas-liquid separators (“Count” from Equation W-15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that did not control emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W-15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W-15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that controlled emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with flares.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with flares.

(E) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with flares.

(3) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting).

(i) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the “T_n” values used in Equation W-16 of this subpart).

(iii) Annual CO_2 emissions, in metric tons CO_2, that resulted from dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(iv) Annual CH_4 emissions, in metric tons CH_4, that resulted from the dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(k) ***Transmission storage tanks.*** You must indicate whether your facility contains any transmission storage tanks. If your facility contains at least one transmission storage tank, then you must report the information specified in paragraphs (k)(1) through (3) of this section for each transmission storage tank vent stack.

(1) For each transmission storage tank vent stack, report the information specified in (k)(1)(i) through (iv) of this section.

(i) The unique name or ID number for the transmission storage tank vent stack.

(ii) Method used to determine if dump valve leakage occurred.

(iii) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to § 98.233(k)(2).

(iv) Indicate if there is a flare attached to the transmission storage tank vent stack.

(2) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each transmission storage vent stack where scrubber dump valve leakage occurred.

(i) Method used to measure the leak rate.

(ii) Measured leak rate (average leak rate from a continuous flow measurement device), in standard cubic feet per hour.

(iii) Duration of time that the leak is counted as having occurred, in hours, as determined in § 98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(k)(1) through (4).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(k)(1) through (4).

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii), and the vent stack vented to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (vi) of this section.

(i) Method used to measure the leak rate.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in § 98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from flaring gas, calculated according to § 98.233(k)(5).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from flaring gas, calculated according to § 98.233(k)(5).

(vi) Annual N_2O emissions, in metric tons N_2O, that resulted from flaring gas, calculated according to § 98.233(k)(5).

(l) ***Well testing.*** You must indicate whether you performed gas well or oil well testing, and if the testing of gas wells or oil wells resulted in vented or flared emissions during the calendar year. If you performed well testing that resulted in vented or flared emissions during the calendar year, then you must report the information specified in paragraphs (l)(1) through (4) of this section, as applicable.

(1) If you used Equation W-17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(2) If you used Equation W-17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (viii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(viii) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(l).

(3) If you used Equation W-17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(4) If you used Equation W-17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vii) of this section.

(i) Number of wells tested in calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(vii) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(l).

(m) ***Associated natural gas.*** You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented or flared during the calendar year, then you must report the information specified in paragraphs (m)(1) through (8) of this section for each sub-basin.

(1) Sub-basin ID and a list of well ID numbers for wells for which associated gas was vented or flared.

(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicate whether any associated gas was flared.

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the "GOR" values used in Equation W-18 of this subpart).

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of "$V_{p,q}$" used in Equation W-18 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of "SG" values used in Equation W-18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (iii) of this section for each sub-basin.

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(3) and (4).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (iv) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(5).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(5).

(iv) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(m)(5).

(n) ***Flare stacks.*** You must indicate if your facility contains any flare stacks. You must report the information specified in paragraphs (n)(1) through (12) of this section for each flare stack at your facility, and for each industry segment applicable to your facility.

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(2) Indicate whether the flare stack has a continuous flow measurement device.

(3) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(4) Volume of gas sent to the flare, in standard cubic feet ("V_s" in Equations W-19 and W-20 of this subpart).

(5) Fraction of the feed gas sent to an un-lit flare ("Z_u" in Equation W-19 of this subpart).

(6) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(7) Mole fraction of CH_4 in the feed gas to the flare ("X_{CH4}" in Equation W-19 of this subpart).

(8) Mole fraction of CO_2 in the feed gas to the flare ("X_{CO2}" in Equation W-20 of this subpart).

(9) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W-20 of this subpart).

(10) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W-19 of this subpart).

(11) Annual N_2O emissions, in metric tons N_2O (refer to Equation W-40 of this subpart).

(12) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then you are not required to report N_2O and CH_4 emissions for the flare stack.

(o) ***Centrifugal compressors.*** You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

(1) ***Compressor activity data.*** Report the information specified in paragraphs (o)(1)(i) through (xiv) of this section for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in not-operating-depressurized-mode.

(iv) Indicate whether the compressor was measured in operating-mode.

(v) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(vii) Indicate which, if any, compressor sources are routed to a flare.

(viii) Indicate which, if any, compressor sources have vapor recovery.

(ix) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(x) Indicate whether the compressor has blind flanges installed and associated dates.

(xi) Indicate whether the compressor has wet or dry seals.

(xii) If the compressor has wet seals, the number of wet seals.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) ***Compressor source.***

(i) For each compressor source at each compressor, report the information specified in paragraphs (o)(2)(i)(A) through (C) of this section.

(A) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(i) of this section.

(B) Centrifugal compressor source (wet seal, isolation valve, or blowdown valve).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in § 98.233(o)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in § 98.233(o)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (o)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) ***As found measurement sample data.*** If the measurement methods specified in § 98.233(o)(2) or

(4) are conducted, report the information specified in paragraph (o)(3)(i) of this section. If the calculation specified in § 98.233(o)(6)(ii) is performed, report the information specified in paragraph (o)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (o)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-23 was used to calculate emissions in Equation W-22, report the information specified in paragraphs (o)(3)(ii)(A) through (D) of this section.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-23).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-23).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) ***Continuous measurement data.*** If the measurement methods specified in § 98.233(o)(3) or

(5) are conducted, report the information specified in paragraphs (o)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in § 98.233(o)(3)(ii) and (o)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) ***Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.*** Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Number of centrifugal compressors that have wet seal oil degassing vents.

(ii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with wet seal oil degassing vents.

(iii) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with wet seal oil degassing vents.

(p) ***Reciprocating compressors.*** You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

(1) ***Compressor activity data.*** Report the information specified in paragraphs (p)(1)(i) through (xiv) of this section for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) Indicate whether the compressor was measured in operating-mode.

(vi) Indicate whether the compressor was measured in standby-pressurized-mode.

(vii) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(viii) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(ix) Indicate which, if any, compressor sources are routed to a flare.

(x) Indicate which, if any, compressor sources have vapor recovery.

(xi) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(xii) Indicate whether the compressor has blind flanges installed and associated dates.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) ***Compressor source.***

(i) For each compressor source at each compressor, report the information specified in paragraphs (p)(2)(i)(A) through (C) of this section.

(A) Reciprocating compressor name or ID. Use the same ID as in paragraph (p)(1)(i) of this section.

(B) Reciprocating compressor source (isolation valve, blowdown valve, or rod packing).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (p)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in § 98.233(p)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in § 98.233(p)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (p)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) ***As found measurement sample data.*** If the measurement methods specified in § 98.233(p)(2) or

(4) are conducted, report the information specified in paragraph (p)(3)(i) of this section. If the calculation specified in § 98.233(p)(6)(ii) is performed, report the information specified in paragraph (p)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (p)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-28 was used to calculate emissions in Equation W-27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-28).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-28).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) ***Continuous measurement data.*** If the measurement methods specified in § 98.233(p)(3) or

(5) are conducted, report the information specified in paragraphs (p)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in § 98.233(p)(3)(ii) and (p)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) ***Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.*** Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Number of reciprocating compressors.

(ii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors.

(iii) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors.

(q) Equipment leak surveys. For any components subject to or complying with the requirements of § 98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (v) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iii) Except for onshore natural gas processing facilities and natural gas distribution facilities, indicate whether any equipment components at your facility are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter. Report the indication per facility, not per component type.

(iv) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with § 98.233(q) according to § 98.233(q)(1)(iv) for any equipment components at your facility.

(v) Report each type of method described in § 98.234(a) that was used to conduct leak surveys.

(2) You must indicate whether your facility contains any of the component types subject to or complying with § 98.233(q) that are listed in § 98.232(c)(21), (d)(7), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero ("0") for the information required according to paragraphs (q)(2)(ii) through (v) of this section.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year ("x_p" in Equation W-30 of this subpart for the component type).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of "$T_{p,z}$" from Equation W-30 of this subpart for the component type).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W-30 (for surveyed components only).

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W-30 (for surveyed components only).

(3) Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraphs (q)(3)(i) through (viii) and, if applicable, (q)(3)(ix) of this section.

(i) Number of above grade transmission-distribution transfer stations surveyed in the calendar year.

(ii) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in the calendar year ("$Count_{MR,y}$" from Equation W-31 of this subpart, for the current calendar year).

(iii) Average time that meter/regulator runs surveyed in the calendar year were operational, in hours (average of "$T_{w,y}$" from Equation W-31 of this subpart, for the current calendar year).

(iv) Number of above grade transmission-distribution transfer stations surveyed in the current leak survey cycle.

(v) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in current leak survey cycle (sum of "$Count_{MR,y}$" from Equation W-31 of this subpart, for all calendar years in the current leak survey cycle).

(vi) Average time that meter/regulator runs surveyed in the current leak survey cycle were operational, in hours (average of "$T_{w,y}$" from Equation W-31 of this subpart, for all years included in the leak survey cycle).

(vii) Meter/regulator run CO_2 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CO_2 per operational hour of all meter/regulator runs ("$EF_{s,MR,i}$" for CO_2 calculated using Equation W-31 of this subpart).

(viii) Meter/regulator run CH_4 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CH_4 per operational hour of all meter/regulator runs ("$EF_{s,MR,i}$" for CH_4 calculated using Equation W-31 of this subpart).

(ix) If your natural gas distribution facility performs equipment leak surveys across a multiple year leak survey cycle, you must also report:

(A) The total number of meter/regulator runs at above grade transmission-distribution transfer stations at your facility ("$Count_{MR}$" in Equation W-32B of this subpart).

(B) Average estimated time that each meter/regulator run at above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run ("$T_{w,avg}$" in Equation W-32B of this subpart).

(C) Annual CO_2 emissions, in metric tons CO_2, for all above grade transmission-distribution transfer stations at your facility.

(D) Annual CH_4 emissions, in metric tons CH_4, for all above grade transmission-distribution transfer stations at your facility.

(r) ***Equipment leaks by population count.*** If your facility is subject to the requirements of § 98.233(r), then you must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable.

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W-32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W-32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the component type, service type and geographic location.

(ii) Total number of the emission source type at the facility ("$Count_e$" in Equation W-32A of this subpart).

(iii) Average estimated time that the emission source type was operational in the calendar year, in hours ("T_e" in Equation W-32A of this subpart).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(v) Annual CH_4 emissions, in metric tons CH_4, for the emission source type.

(2) Natural gas distribution facilities must also report the information specified in paragraphs (r)(2)(i) through (v) of this section.

(i) Number of above grade transmission-distribution transfer stations at the facility.

(ii) Number of above grade metering-regulating stations that are not transmission-distribution transfer stations at the facility.

(iii) Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations ("$Count_{MR}$" in Equation W-32B of this subpart).

(iv) Average estimated time that each meter/regulator run at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run ("$T_{w,avg}$" in Equation W-32B of this subpart).

(v) If your facility has above grade metering-regulating stations that are not above grade transmission-distribution transfer stations and your facility also has above grade transmission-distribution transfer stations, you must also report:

(A) Annual CO_2 emissions, in metric tons CO_2, from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(B) Annual CH_4 emissions, in metric tons CH_4, from above grade metering regulating stations that are not above grade transmission-distribution transfer stations.

(3) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

(i) Calculation method used.

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W-1B and W-1C to this subpart for which equipment leak emissions are calculated using the methodology in § 98.233(r).

(A) An indication of whether the facility contains the major equipment type.

(B) If the facility does contain the equipment type, the count of the major equipment type.

(s) ***Offshore petroleum and natural gas production.*** You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEMRE study.

(1) Annual CO_2 emissions, in metric tons CO_2.

(2) Annual CH_4 emissions, in metric tons CH_4.

(3) Annual N_2O emissions, in metric tons N_2O.

(t) [Reserved]

(u) [Reserved]

(v) [Reserved]

(w) ***EOR injection pumps.*** You must indicate whether CO_2 EOR injection was used at your facility during the calendar year and if any EOR injection pump blowdowns occurred during the year. If any EOR injection pump blowdowns occurred during the calendar year, then you must report the information specified in paragraphs (w)(1) through (8) of this section for each EOR injection pump system.

(1) Sub-basin ID.

(2) EOR injection pump system identifier.

(3) Pump capacity, in barrels per day.

(4) Total volume of EOR injection pump system equipment chambers, in cubic feet ("V_v" in Equation W-37 of this subpart).

(5) Number of blowdowns for the EOR injection pump system in the calendar year.

(6) Density of critical phase EOR injection gas, in kilograms per cubic foot ("R_c" in Equation W-37 of this subpart).

(7) Mass fraction of CO_2 in critical phase EOR injection gas ("GHG_{CO2}" in Equation W-37 of this subpart).

(8) Annual CO_2 emissions, in metric tons CO_2, from EOR injection pump system blowdowns.

(x) ***EOR hydrocarbon liquids.*** You must indicate whether hydrocarbon liquids were produced through EOR operations. If hydrocarbon liquids were produced through EOR operations, you must report the information specified in paragraphs (x)(1) through (4) of this section for each sub-basin category with EOR operations.

(1) Sub-basin ID.

(2) Total volume of hydrocarbon liquids produced through EOR operations in the calendar year, in barrels ("V_{hl}" in Equation W-38 of this subpart).

(3) Average CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel under standard conditions ("S_{hl}" in Equation W-38 of this subpart).

(4) Annual CO_2 emissions, in metric tons CO_2, from CO_2 retained in hydrocarbon liquids produced through EOR operations downstream of the storage tank ("$Mass_{CO2}$" in Equation W-38 of this subpart).

(y) [Reserved]

(z) ***Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.*** If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xviii), (a)(8)(i), or (a)(9)(xii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) and (ii) of this section for each unit type.

(i) The type of combustion unit.

(ii) The total number of combustion units.

(2) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or, internal fuel combustion units of any heat capacity that are compressor-drivers. If your facility contains: External fuel combustion units with a rated heat capacity greater than 5 mmBtu/hr; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or internal fuel combustion units of any heat capacity that are compressor-drivers, then you must report the information specified in paragraphs (z)(2)(i) through (vi) of this section for each combustion unit type and fuel type combination.

(i) The type of combustion unit.

(ii) The type of fuel combusted.

(iii) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) and (2).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) and (2).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) and (2).

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.

(1) For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (ii) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (C) of this section for the basin as a whole.

(A) The quantity of gas produced in the calendar year from wells, in thousand standard cubic feet. This includes gas that is routed to a pipeline, vented or flared, or used in field operations. This does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production.

(B) The quantity of gas produced in the calendar year for sales, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced in the calendar year for sales, in barrels.

(ii) Report the information specified in paragraphs (aa)(1)(ii)(A) through (M) of this section for each unique sub-basin category.

(A) State.

(B) County.

(C) Formation type.

(D) The number of producing wells at the end of the calendar year and a list of the well ID numbers (exclude only those wells permanently taken out of production, *i.e.*, plugged and abandoned).

(E) The number of producing wells acquired during the calendar year and a list of the well ID numbers.

(F) The number of producing wells divested during the calendar year and a list of the well ID numbers.

(G) The number of wells completed during the calendar year and a list of the well ID numbers.

(H) The number of wells permanently taken out of production (*i.e.*, plugged and abandoned) during the calendar year and a list of the well ID numbers.

(I) Average mole fraction of CH_4 in produced gas.

(J) Average mole fraction of CO_2 in produced gas.

(K) If an oil sub-basin, report the average GOR of all wells, in thousand standard cubic feet per barrel.

(L) If an oil sub-basin, report the average API gravity of all wells.

(M) If an oil sub-basin, report average low pressure separator pressure, in pounds per square inch gauge.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) and (ii) of this section.

(i) The total quantity of gas handled at the offshore platform in the calendar year, in thousand standard cubic feet, including production volumes and volumes transferred via pipeline from another location.

(ii) The total quantity of oil and condensate handled at the offshore platform in the calendar year, in barrels, including production volumes and volumes transferred via pipeline from another location.

(3) For natural gas processing, report the information specified in paragraphs (aa)(3)(i) through (vii) of this section.

(i) The quantity of natural gas received at the gas processing plant in the calendar year, in thousand standard cubic feet.

(ii) The quantity of processed (residue) gas leaving the gas processing plant in the calendar year, in thousand standard cubic feet.

(iii) The cumulative quantity of all NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.

(iv) The cumulative quantity of all NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.

(v) Average mole fraction of CH_4 in natural gas received.

(vi) Average mole fraction of CO_2 in natural gas received.

(vii) Indicate whether the facility fractionates NGLs.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of gas transported through the compressor station in the calendar year, in thousand standard cubic feet.

(ii) Number of compressors.

(iii) Total compressor power rating of all compressors combined, in horsepower.

(iv) Average upstream pipeline pressure, in pounds per square inch gauge.

(v) Average downstream pipeline pressure, in pounds per square inch gauge.

(5) For underground natural gas storage, report the quantities specified in paragraphs (aa)(5)(i) through (iii) of this section.

(i) The quantity of gas injected into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(6) For LNG import equipment, report the quantity of LNG imported in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported in the calendar year, in thousand standard cubic feet.

(8) For LNG storage, report the quantities specified in paragraphs (aa)(8)(i) through (iii) of this section.

(i) The quantity of LNG added into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of LNG withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) For natural gas distribution, report the quantities specified in paragraphs (aa)(9)(i) through (vii) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas delivered to end users, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(v) The quantity of natural gas transferred to third parties such as other LDCs or pipelines, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(vi) The quantity of natural gas consumed by the LDC for operational purposes, in thousand standard cubic feet.

(vii) The estimated quantity of gas stolen in the calendar year, in thousand standard cubic feet.

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (iv) of this section.

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline for each state in the facility.

(bb) For any missing data procedures used, report the information in § 98.3(c)(8) except as provided in paragraphs (bb)(1) and (2) of this section.

(1) For quarterly measurements, report the total number of quarters that a missing data procedure was used for each data element rather than the total number of hours.

(2) For annual or biannual (once every two years) measurements, you do not need to report the number of hours that a missing data procedure was used for each data element.

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (g)(5)(iii)(A), (g)(5)(iii)(B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

[79 FR 70411, Nov. 24, 2014, as amended at 80 FR 64291, Oct. 22, 2015; 81 FR 86515, Nov. 30, 2016]

§ 98.237 Records that must be retained.

Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by § 98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

(e) The records required under § 98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

(f) For each time a missing data procedure was used, keep a record listing the emission source type, a description of the circumstance that resulted in the need to use missing data procedures, the missing data provisions in § 98.235 that apply, the calculation or analysis used to develop the substitute value, and the substitute value.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011; 79 FR 70424, Nov. 25, 2014]

§ 98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (*e.g.,* an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Associated gas venting or flaring means the venting or flaring of natural gas which originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. This does not include venting or flaring resulting from activities that are reported elsewhere, including tank venting, well completions, and well workovers.

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. Onshore production storage tanks on or associated with a single well-pad are considered a part of the onshore production facility.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see § 98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see § 98.7).

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Compressor mode means the operational and pressurized status of a compressor. For a centrifugal compressor, "mode" refers to either operating-mode or not-operating-depressurized-mode. For a reciprocating compressor, "mode" refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor source means the source of certain venting or leaking emissions from a centrifugal or reciprocating compressor. For centrifugal compressors, "source" refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and wet seal oil degassing vents. For reciprocating compressors, "source" refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and rod packing emissions.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Distribution pipeline means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements
means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements
means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements
means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in this section. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in this subpart.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements
means all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Facility with respect to the onshore natural gas transmission pipeline segment means the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator as defined in this section. The facility does not include pipelines that are part of any other industry segment defined in this subpart.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see § 98.7).

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and -pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to −260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Manifolded compressor source means a compressor source (as defined in this section) that is manifolded to a common vent that routes gas from multiple compressors.

Manifolded group of compressor sources means a collection of any combination of manifolded compressor sources (as defined in this section) that are manifolded to a common vent.

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow, or both, in the natural gas distribution industry segment. At least one meter, at least one regulator, or any combination of both on a single run of piping is considered one meter/regulator run.

Metering-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in § 98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pressure groups as applicable to each sub-basin are defined as follows: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reduced emissions completion means a well completion following hydraulic fracturing where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions completion may occur.

Reduced emissions workover means a well workover with hydraulic fracturing (*i.e.,* refracturing) where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions workover may occur.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and *Residue Gas Compression* mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce only from high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids (with or without gas) and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight gas reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-distribution (T-D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994).

Tubing diameter groups are defined as follows: Outer diameter less than or equal to 1 inch; outer diameter greater than 1 inch and less than 2.375 inch; and outer diameter greater than or equal to 2.375 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well identification (ID) number means the unique and permanent identification number assigned to a petroleum or natural gas well. If the well has been assigned a US Well Number, the well ID number required in this subpart is the US Well Number. If a US Well Number has not been assigned to the well, the well ID number is the identifier established by the well's permitting authority.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011; 79 FR 63794, Oct. 24, 2014; 79 FR 70424, Nov. 25, 2014; 80 FR 64296, Oct. 22, 2015]

Table W-1A to Subpart W of Part 98 - Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities

Table W-1A to Subpart W of Part 98 - Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/ component)
Eastern U.S.	
Population Emission Factors - All Components, Gas Service[1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors - All Components, Light Crude Service[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors - All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors - Gathering Pipelines, by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
Western U.S.	
Population Emission Factors - All Components, Gas Service[1]	

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/ component)
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors - All Components, Light Crude Service[4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors - All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors - Gathering Pipelines by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1] For multi-phase flow that includes gas, use the gas service emissions factors.

[2] Emission Factor is in units of "scf/hour/device."

[3] Emission Factor is in units of "scf/hour/pump."

[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."

[7] Emission factors are in units of "scf/hour/mile of pipeline."

[80 FR 64297, Oct. 22, 2015]

Table W-1B to Subpart W of Part 98 - Default Average Component Counts for Major Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

[75 FR 74488, Nov. 30, 2010, as amended at 80 FR 64298, Oct. 22, 2015]

Table W-1C to Subpart W of Part 98 - Default Average Component Counts For Major Crude Oil Production Equipment

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

Table W-1D to Subpart W of Part 98 - Designation Of Eastern And Western U.S.

Eastern U.S.	Western U.S.
Connecticut	Alabama
Delaware	Alaska
Florida	Arizona
Georgia	Arkansas
Illinois	California
Indiana	Colorado
Kentucky	Hawaii
Maine	Idaho
Maryland	Iowa
Massachusetts	Kansas
Michigan	Louisiana
New Hampshire	Minnesota
New Jersey	Mississippi
New York	Missouri
North Carolina	Montana
Ohio	Nebraska
Pennsylvania	Nevada
Rhode Island	New Mexico
South Carolina	North Dakota
Tennessee	Oklahoma
Vermont	Oregon
Virginia	South Dakota
West Virginia	Texas
Wisconsin	Utah
	Washington
	Wyoming

Table W-1E to Subpart W of Part 98 - Default Whole Gas Leaker Emission Factors for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting

Equipment components	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors - All Components, Gas Service[1]		
Valve	4.9	3.5

Equipment components	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Flange	4.1	2.2
Connector (other)	1.3	0.8
Open-Ended Line[2]	2.8	1.9
Pressure Relief Valve	4.5	2.8
Pump Seal	3.7	1.4
Other[3]	4.5	2.8
Leaker Emission Factors - All Components, Light Crude Service[1]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other[3]	3.1	2.0
Leaker Emission Factors - All Components, Heavy Crude Service[1]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other[3]	3.1	2.0

[1] For multi-phase flow that includes gas, use the gas service emission factors.

[2] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.

[3] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).

[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

[5] Hydrocarbon liquids less than 20°API are considered "heavy crude."

[81 FR 86515, Nov. 30, 2016]

Table W-2 to Subpart W of Part 98 - Default Total Hydrocarbon Emission Factors for Onshore

Natural Gas Processing

Onshore natural gas processing plants	Emission factor (scf/hour/component)
Leaker Emission Factors - Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors - Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

[1] Valves include control valves, block valves and regulator valves.

[76 FR 80592, Dec. 23, 2011]

Table W-3A to Subpart W of Part 98 - Default Total Hydrocarbon Leaker Emission Factors for Onshore Natural Gas Transmission Compression

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors - Compressor Components, Gas Service		
Valve[1]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter or Instrument	19.33	12.39
Other[2]	4.1	2.63
Leaker Emission Factors - Non-Compressor Components, Gas Service		
Valve[1]	6.42	4.12
Connector	5.71	3.66
Open-Ended Line	11.27	7.22
Pressure Relief Valve	2.01	1.29
Meter or Instrument	2.93	1.88

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Other[2]	4.1	2.63

[1] Valves include control valves, block valves and regulator valves.

[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(e)(8).

[81 FR 86516, Nov. 30, 2016]

Table W-3B to Subpart W of Part 98 - Default Total Hydrocarbon Population Emission Factors for Onshore Natural Gas Transmission Compression

Table W-3B to Subpart W of Part 98 - Default Total Hydrocarbon Population Emission Factors for Onshore Natural Gas Transmission Compression

Population emission factors - gas service onshore natural gas transmission compression	Emission factor (scf/hour/ component)
Low Continuous Bleed Pneumatic Device Vents[1]	1.37
High Continuous Bleed Pneumatic Device Vents[1]	18.20
Intermittent Bleed Pneumatic Device Vents[1]	2.35

[1] Emission Factor is in units of "scf/hour/device."

[81 FR 86516, Nov. 30, 2016]

Table W-4A to Subpart W of Part 98 - Default Total Hydrocarbon Leaker Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors - Storage Station, Gas Service		
Valve[1]	14.84	9.51
Connector (other)	5.59	3.58

Underground natural gas storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[2]	4.1	2.63
Leaker Emission Factors - Storage Wellheads, Gas Service		
Valve[1]	4.5	3.2
Connector (other than flanges)	1.2	0.7
Flange	3.8	2.0
Open-Ended Line	2.5	1.7
Pressure Relief Valve	4.1	2.5
Other[2]	4.1	2.5

[1] Valves include control valves, block valves and regulator valves.

[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(f)(6) and (8).

[81 FR 86517, Nov. 30, 2016]

Table W-4B to Subpart W of Part 98 - Default Total Hydrocarbon Population Emission Factors for Underground Natural Gas Storage

Table W-4B to Subpart W of Part 98 - Default Total Hydrocarbon Population Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission factor (scf/hour/component)
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Population Emission Factors - Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[1]	1.37
High Continuous Bleed Pneumatic Device Vents[1]	18.20
Intermittent Bleed Pneumatic Device Vents[1]	2.35

[1] Emission Factor is in units of "scf/hour/device."

[81 FR 86517, Nov. 30, 2016]

Table W-5A to Subpart W of Part 98 - Default Methane Leaker Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors - LNG Storage Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other[1]	1.77	0.99
Leaker Emission Factors - LNG Storage Components, Gas Service		
Valve[2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and	19.33	12.39

LNG storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Instrument		
Other[3]	4.1	2.63

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[2] Valves include control valves, block valves and regulator valves.

[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(g)(6) and (7).

[81 FR 86518, Nov. 30, 2016]

Table W-5B to Subpart W of Part 98 - Default Methane Population Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[1]	4.17

[1] Emission Factor is in units of "scf/hour/device."

[81 FR 86518, Nov. 30, 2016]

Table W-6A to Subpart W of Part 98 - Default Methane Leaker Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors - LNG Terminals Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11

LNG import and export equipment	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Other[1]	1.77	0.99
Leaker Emission Factors - LNG Terminals Components, Gas Service		
Valve[2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[3]	4.1	2.63

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[2] Valves include control valves, block valves and regulator valves.

[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(h)(7) and (8).

[81 FR 86518, Nov. 30, 2016]

Table W-6B to Subpart W of Part 98 - Default Methane Population Emission Factors for LNG Import and Export Equipment

Table W-6B to Subpart W of Part 98 - Default Methane Population Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor[1]	4.17

[1] Emission Factor is in units of "scf/hour/compressor."

[81 FR 86518, Nov. 30, 2016]

Table W-7 to Subpart W of Part 98 - Default Methane Emission Factors for Natural Gas Distribution

Natural gas distribution	Emission factor (scf/hour/ component)
Leaker Emission Factors - Transmission-Distribution Transfer Station[1] Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors - Below Grade Metering-Regulating station[1] Components, Gas Service[2]	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population Emission Factors - Distribution Mains, Gas Service[3]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors - Distribution Services, Gas Service[4]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] Excluding customer meters.

[2] Emission Factor is in units of "scf/hour/station."

[3] Emission Factor is in units of "scf/hour/mile."

[4] Emission Factor is in units of "scf/hour/number of services."

[76 FR 80594, Dec. 23, 2011]

Division 1-3

Request:

Provide the most recent calendar year estimate of the total calculated methane emission associated with all remaining leak prone pipe throughout the Company's Rhode Island gas distribution system. Explain and provide the calculation for the Company's estimate.

Response:

For 2021, estimated methane emission associated with leak prone pipe is 259,013 MCF. Estimated emissions associated with total system inventory is 280,239 MCF. The table below shows the 2021 Main and Service inventory by material type along with the estimated emissions. The cells shaded gray are the emissions related to leak prone pipe, which total the estimated 259,013 MCF.

		Unprotected		Protected									
		BARE	COATED	BARE	COATED	DUCTILE IRON	COPPER	CAST/ WROUGHT IRON	PLASTIC	OTHER	RECONDITIONED CAST IRON	TOTAL	
2021 INVENTORY	MAIN	158	139	-	586	13	-	632	1,698	0	0	3,227	MILES
	SERVICE	37,915	5,496	-	7,153	-	71	25	142,839	951	-	194,450	COUNT
2021 EMISSION	MAIN	17,459	15,354	-	1,797	3,017	-	150,859	16,811	2	114	205,413	MCF
	SERVICE	63,106	9,148	-	1,253	-	19	42	1,251	8	-	74,826	MCF
												280,239	MCF

Prepared by or under the supervision of: Lee Gresham

Division 1-4

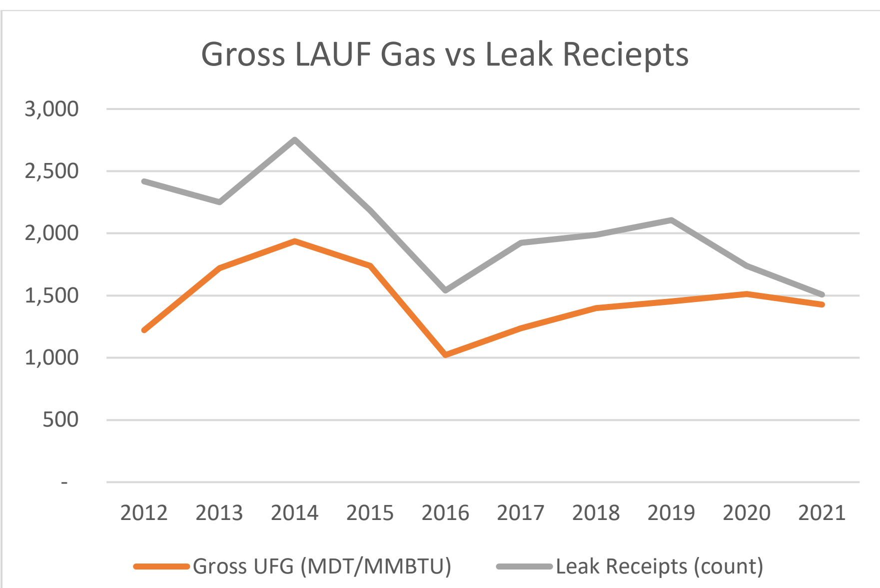
Request:

What percentage of the Company's overall unaccounted for gas is associated with leak prone pipe? Provide the Company's unaccounted for gas for each CY from 2012 to 2021? Explain the relationship between the trend in unaccounted for gas and leak receipts over the same period.

Response:

Please see the table below for the Company's lost and unaccounted for gas for calendar year 2012 through 2021. As of 2021, leak prone main and service contributes 20.1% of overall lost and unaccounted for gas. Please note, the lost and unaccounted for gas values that are reported in the Company's annual System Integrity Reports deduct the volume of gas associated with leak prone pipe, since there is a known estimated value for that gas, thus it is accounted for.

	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
Leak Receipts (count)	2,417	2,252	2,753	2,183	1,541	1,924	1,989	2,107	1,738	1,508



Prepared by or under the supervision of: Barry Foster

Division 1-4, page 2

As shown above, the relationship between the trend in gross lost and unaccounted for gas and leak receipts could be weather related.

Division 1-5

Request:

On Page 8, the Company states that the 21-Month Plan will result in an abandonment target of 49.6 miles of leak prone pipe for CY 2023 and 66.6 miles for CY 2024. Please provide a chart showing the actual abandoned miles for CY 2017 – CY 2021 by the Company. In the chart, for each calendar year show the abandoned miles of pipe for each proactive pipe replacement program.

Response:

The last paragraph on Page 8 of the 21-month ISR proposal contained a typographical error in relation to the specific abandonment targets for the 9-month CY 2023 Plan and 12-month CY 2024 Plan. The incorrect sentence stated: *"This results in abandonment targets of 49.6 miles for CY 2023 and 66.6 miles for CY 2024."* The **correct values** (which is not a change in the plan) are as follows:
"This results in abandonment targets of 51.0 miles for 9-month CY 2023 and 69.5 miles for CY 2024."

The Company will make this correction in the 21-month ISR plan proposal that will be submitted to the Rhode Island Public Utilities Commission ("PUC") in December 2022.

The Company has tracked its abandonment progress by Fiscal Year, rather than Calendar Year, in the past. The table below, therefore, represents the period from April 1, 2017 through March 31, 2022.

Year	Public Works	Proactive Main Replacement	Other	Total Installed		Public Works	Proactive Main Replacement	Other	Total Abandoned
FY18	12.4	46.0	3.1	61.5		12.1	48.5	1	61.6
FY19	8.9	46.6	6.1	61.6		12.2	47.7	0.5	60.4
FY20	14.6	46.9	1.9	63.4		11.8	48.3	1.5	61.6
FY21	9.9	45.1	2.2	57.2		5.4	23.4	1.3	30.1
FY22	14.0	41.1	1.4	56.5		14	53.2	0.7	67.9

Prepared by or under the supervision of: Phil Lafond

Division 1-6

Request:

On Pages 17-18, the Company states with respect to its Purchase Meter Replacement Program it will require 14,820 meters for CY 2023 and 19,759 meters for CY 2024. The FY 2023 Gas ISR quarterly report through June 30, 2022 states that the Company has a physical count inventory of 7,354. The Company then states it is "planning to purchase 21,770 meters in CY 2023" and "planning to purchase 32,107 meters in CY 2024." With respect to these statements, please provide the following:

(a) What is the most recent physical count of meters?

(b) Explain in much greater detail than is contained in the filing why the Company is proposing to purchase 21,770 meters for CY 2023 and 32,107 meters for CY 2024.

(c) Why does the Company need to increase its current inventory above previous levels?

(d) Provide documentation and analysis that support the proposed 21,770 and 32,107 meter purchase figures.

Response:

(a) There are 6,201 meters in inventory as of the most recent physical count taken on October 31, 2022.

(b) The Company is proposing to purchase 21,770 meters for CY 2023 and 32,107 meters for CY 2024 to compensate for the adverse effects of supply chain disruptions on its current inventory, and to increase the supply of meters to prevent risk to future work caused by continued supply chain issues. During CY 2022, meter vendor lead times have lengthened to more than a year beyond the original scheduled delivery dates for meter orders placed prior to January 2022, and in many cases even longer for meter orders placed in mid-CY 2022 for CY 2023 and CY 2024. These deferrals resulted in a reduction in the number of meters forecasted to arrive during FY 2023 and increased the number of meters forecasted to arrive during CY 2023 and CY 2024. In response to these supply chain issues, the Company plans to maintain a 12-month inventory of meters (between 21,000 and 22,000 meters), which is an increase from the prior practice of maintaining a 3-month inventory of meters, or between 5,250 and 5,500 meters.

Division 1-6, page 2

(c) The Company is proposing to increase its meter inventory to maintain a 12-month supply of meters to prevent the risk of meter shortages caused by supply chain issues, as discussed in part (b), above. Supply chain problems have resulted in a declining inventory throughout CY 2022 and created prolonged lead times for meter orders placed for the CY 2023 and CY 2024. With an increased meter inventory, the Company will be able to continue its planned and mandated meter work unhindered by meter supply issues.

(d) To determine the predicted year-end inventory for the proposed 9-month period of CY 2023, the starting inventory for CY 2023 (i.e., end of FY 2023) was projected based on the current meter inventory plus refurbished meters and anticipated deliveries as scheduled by the vendor, less planned meter installations. As the delivery schedule has fluctuated frequently in CY 2022 due to vendor supply chain problems, the anticipated delivery dates have been altered by the vendors on a nearly continuous basis. The most recent meter vendor delivery dates combined with the Company's planned installations and meter changes yielded an anticipated starting inventory for the 9-month period in CY 2023 of 3,809 meters. From this value, the anticipated 9-month CY 2023 mandated, growth, and miscellaneous meter installations were subtracted, and the anticipated 9-month CY 2023 refurbishment and purchase values were added to yield a projected 9-month CY 2023 ending inventory of 9,419 meters, or just below 6 months' worth of meter inventory. The purchase quantity of 21,770 meters for the 9-month period of CY 2023, therefore, represents our effort to expand the inventory toward the 12-month target and reflects the actual number of meters projected to arrive in the 9-month CY 2023 period, based on the most recent delivery schedules from the vendors.

To determine the required purchase quantity for CY 2024 to maintain a 12-month inventory, the CY 2024 ending inventory was set equal to the annual number of meters planned for mandated, growth and miscellaneous installations, less the number of meters anticipated to return to the inventory through refurbishment. Then, the required purchase amount was determined based on the difference between the projected starting and ending inventory values for CY 2024, less the anticipated refurbishment quantity, plus the meters planned for installation in mandated growth and miscellaneous categories. This assessment was conducted again with the most recent vendor schedules and refurbishment numbers during the week of November 14, 2022 and yielded a required purchase number of 32,871 meters for CY 2024.

Please see the table, below, which displays the factors and outcomes of the assessment described above in this part (d). The table indicates the given and calculated quantities the Company uses to create the annual meter purchase plan. By the end of CY 2024,

Division 1-6, page 3

the goal is to have an inventory of 21,145 meters to achieve the 12-month supply, which will insulate the meter program from supply chain risk.

RI	+	-	+	+	-	-	
FY	Starting Inventory	Mandated	Refurbished Meters	Purchase	Growth	Misc	Ending inventory
CY 2023 (9-month)	3,809	13,980	1,035	21,770	2,375	840	9,419
CY 2024 (12-month)	9,419	18,640	1,380	32,871	2,765	1,120	21,145

Division 1-7

Request:

With respect to the main and service replacement work at Oxbow Farms in Middletown, RI on Page 19:

(a) Are the costs associated with the main and service replacements for work at Oxbow Farms included in the $2.04 million 21-month forecast?

(b) Update the Division as to the status of the discussions of the "long-range solution" with the owner of the property.

Response:

(a) No, the 21-month budget does not include the costs for the Oxbow Farms main and service replacement project.

(b) The Company presented the electrification option to the customer at an approximate out of pocket cost of $8 million, and the customer was not interested in pursuing that option. The Company is assessing whether this location is a good candidate for electrification, ground source heat pump, or other non-pipes alternatives. The Company will likely make a decision regarding its assessment during the 21-month period and will communicate that decision to the customer.

If the ultimate solution is determined to be the original gas main and service replacement, the Company is prepared to move forward with the project as soon as practical by substituting it in lieu of another project or projects from the current portfolio in consultation with the Division.

Division 1-8

Request:

On Page 19, for Proactive Low-Pressure System Elimination, provide a breakdown of all phases of the Middletown project including a description, a site plan and a cost estimate for each phase that will contribute to the eventual abandonment of the Walcott Avenue/Briarwood Avenue Low Pressure regulator station.

Response:

Phase 1 - Purgatory Road, Public works project (related to LP System Elimination
but not sponsored by this budget)
This is the first of the 3 phases due to the priority level of the work required.
28 Services involved, Estimate: $0.67M
Install 3,565 ft of PL 99 psi main
Abandon 3,205 ft of Low Pressure ("LP") main (2,010 ft of Leak Prone Pipe ("LPP"), 1195 ft of non LPP)

Phase 2 - Tuckerman Avenue, Low Pressure System Elimination
112 services, Estimate: $1.56M
Install 8,300 ft of PL 99 psi
Abandon 8,400 ft of LP (300 ft of LPP, 8,100 of non LPP)
Temporary Regulator Station Run at single feed station required during the phase due to lower demand from LP to 99 psi service transfers.

Phase 3 - Wolcott Ave, Low Pressure System Elimination
125 services, Estimate: $2.10M
Install 10,735 ft of PL 99 psi
Abandon 11,200 ft of LP (2,470 ft LPP, 8,730 ft of non LPP
Abandon Regulator Station Wolcott @ St. George

Please see Attachment Division 1-8 for the requested site plans for each phase of this project.

Wolcott Ave LP to 99# & LP Station Abandonment

Scope Overview -

- Phase 1 Description: (Public Works job, Separate from LP System Elimination Program) 90000230192 – 240-443 Purgatory Rd MDT- Install 3,565 ft PL 99#, Abandon 3,205 ft (2,010 ft of LPP, 1195 ft of non LPP) 28 services. (Estimate: $673,079.89)
- Phase 2 Description: 90000221104- Tuckerman Av MDT – 8,300 ft main installation PL 99#, 8,400 ft of main abandonment (300 ft LPP, 8100 ft of non LPP. 112 Services. - (Estimate: $1,557,916.89)
- Phase 2- Temp Reg Run required- Lower flow requires swapping out regulator with smaller size run.
- Phase 3 Description: 90000229980 – Wolcott Ave MDT-10735 ft main installation PL 99#, 11,200 ft LP main abandonment (2,470 ft LPP, 8,730 ft non LPP. 125 services (Estimate: $2,082,709.85)
- Phase 3-LP station Abandonment

The site plan contains confidential critical
energy infrastructure information
and is being provided to the Division via a separate link.

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energy infrastructure information
and is being provided to the Division via a separate link.

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Division 1-9

Request:

For the Scott Road Take Station Project on Page 21, provide an update of the project and in your update include a detailed description, a site plan, the updated total costs, and a construction timeline. Also explain why this project has been delayed.

Response:

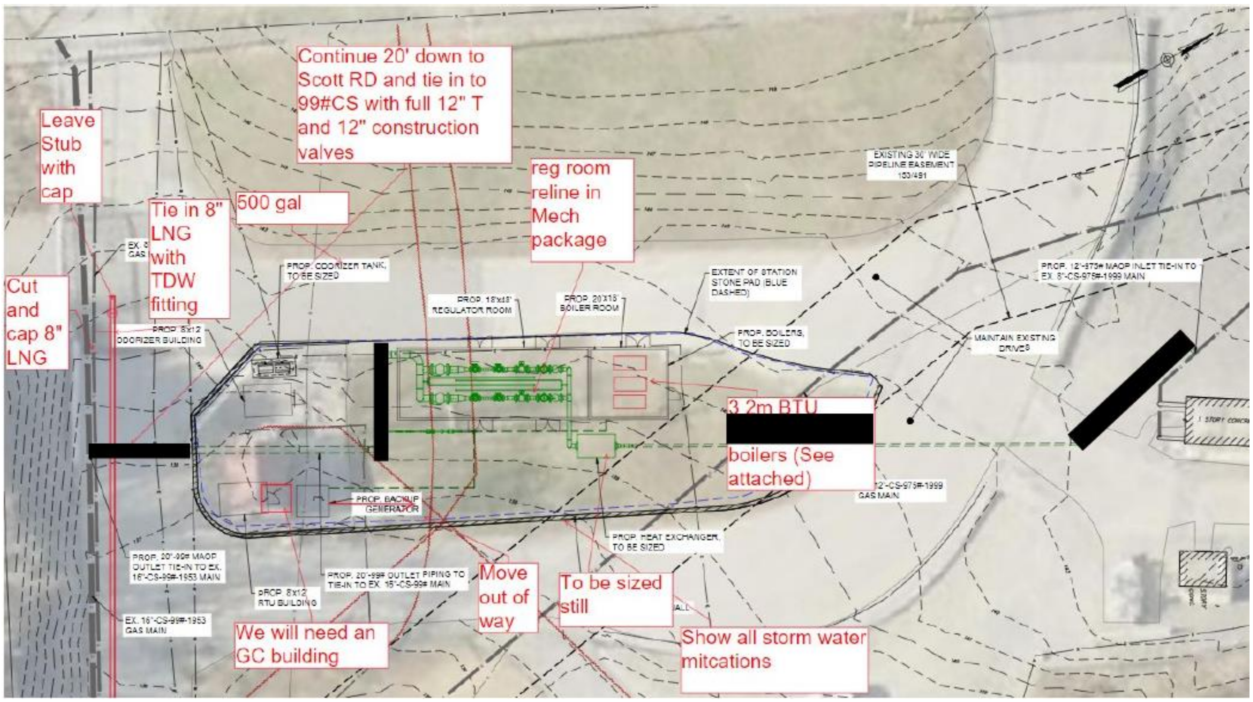
The final proposed scope of work for the Scott Road Take Station Project has been completed. The engineering is now 60 percent complete with some long-lead time materials on order. The scope of work is to install a new above-ground gate station building with new regulator runs, heating system, odorant system, communication/electrical installation, as well as new 975 PSIG inlet piping and 99 PSIG outlet piping. An updated cost breakdown and total costs are provided in the table below. A detailed construction timeline will be developed when design is approximately 90% completed. The current timeline is to complete a tie-in tap to the Tennessee Gas pipeline in summer 2023, start station construction in March 2024, and gas-in during October 2024.

Time period	**Cost**	**Description**
Pre FY 2023 Actuals	$0.257M	Engineering, survey, test holes
FY 2023 Forecast	$0.270M	Engineering, long-lead material procurement, and pipe integrity testing
9-Month CY 2023	$3.500M	Final Engineering and material procurement, initial site preparation and initial inlet tapping
CY 2024	$7.460M	Complete construction and fall gas-in target
Total Cost	**$11.487M**	

The total projected spend of $11.487 million will contribute to plant additions of $11.01 million in CY 2024. The abandonment costs projected in CY2024 may carry over into CY2025; however, this will not be determined until a detailed construction schedule is developed. The project has been delayed due to design changes following testing of existing 1953 outlet piping that will now need to be replaced. There were also storm water runoff concerns, which required additional civil engineering. Additional delays were related to concerns over station sizing because of existing and future upstream supply capacity.

Please see the requested site plan below.

Division 1-9, Page 2



Division 1-10

Request:

Provide a detailed description of the Wampanoag Trail Gate Station project on Page 21. Please include a site plan, the total costs, and a construction timeline. Also include before and after plans depicting what components are or will be owned by RIE and answer the following additional questions:

(a) Who will be responsible for construction, Enbridge or RIE?

(b) Explain what problems occur due to not owning and maintaining this facility.

(c) Will this work continue around the newly installed heaters? Please explain.

Response:

The following is a description of the Wampanoag Trail Gate Station project, including a site plan, total costs and construction timeline, as well as ownership plans. Responses to parts (a) through (c) begin on the following page.

The forecasted total costs and construction timeline are as follows:

9 Month CY 2023	$0.660M	Engineering and long-lead materials
CY 2024	$1.710M	Material procurement, outlet piping, site prep
CY2025	$5.400M	Station construction and closeout
Total	**$7.770M**	

Several design options will be considered including, without limitation, one building housing both Enbridge and Rhode Island Energy assets or two separate buildings. Enbridge will own and operate the filter separator, metering runs, and associated piping. Rhode Island Energy will own and operate the heaters as well as regulation equipment, and associated piping. Existing and proposed Rhode Island Energy ownership is highlighted below as well as the configuration which proposes metering runs upstream of regulation.

<u>Division 1-10, page 2</u>

Below is a site plan overview of the replacement project at Wampanoag Trail Gate Station. This site plan contains confidential critical energy infrastructure information. The Company is providing this information to the Division pursuant to the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022.

Due to the highly sensitive and confidential nature of the site plan embedded in this response, the Company is providing the confidential version of this response via separate link.

[redacted]

Prepared by or under the supervision of: Justin Zaccari

Division 1-10, page 3

The tables below show the current and proposed ownership configurations of the gate station:

Pressure Regulation		**X**
Outlet Piping	**X**	

Proposed Ownership

	Rhode Island Energy	**Enbridge**
Inlet Piping		**X**
Filter Separator		**X**
Heaters	**X**	
Metering		**X**
Pressure Regulation	**X**	
Outlet Piping	**X**	

a) Enbridge will be responsible for construction.

b) Not owning this facility prevents Rhode Island Energy from making necessary upgrades to improve safety and reliability of the system. Ownership would allow Rhode Island Energy to provide pressure control and have direct oversight over three layers of overpressure protection to its downstream customers. Upstream operators are required to provide gas supply and ensure that maximum allowable operating pressure of its own piping is not exceeded, but they are not required to provide pressure regulation and overpressure protection to downstream customers. Additionally, records reviews are difficult to perform and require voluntary turnover of information from the upstream operator to ensure that records are traceable, verifiable, and complete. In addition, it prevents Rhode Island Energy from performing non-destructive testing and examination that ensures the integrity of the piping that directly feeds its system. Not maintaining this facility prevents Rhode Island Energy from having responsibility for annual inspection, performing general proactive maintenance activities including annual boot replacements on its regulators, and controlling corrosion of the facility to extend the operational life of the facility and ensure deficiencies are identified and remediated.

c) This work will continue around the newly installed heaters, and they would be protected during construction. The new station is downstream of the heaters and new piping with a flange that separates new inlet piping from existing piping that would be replaced because of this project.

Prepared by or under the supervision of: Justin Zaccari

Division 1-11

Request:

Provide an updated risk ranking of the 12 of 24 transmission stations on Page 21 that are in scope for re-testing and/or replacing equipment.

Response:

The table below shows the list of stations, the relative overall risk ranking based on the complete station risk ranking as shown in Division 1-33 as well as an independent risk ranking associated with the number of missing asset records.

Station Name	Town	Original Install Year	Inlet MAOP	Downstream MAOP	Overall Risk Ranking	Records Integrity Risk Ranking
EL PASO (TGT1) 68 Scott Rd TS	Cumberland	1956	975	99	1	3
Wampanoag Trail TS (Wampanoag Trail @ Tripps Lane)	East Providence	1954	750	200	2	1
67 Laten Knight Rd TS	Cranston	1992	975	200	3	8
135 Old Mill Lane TS	Portsmouth	1999	750	99	4	9
EL PASO (TGT2 116) 600 George Washington Hwy	Lincoln	1992	975	99	5	7
347 Putnam Pike TS (Rt 44) (RIS-125/RIS402)	Smithfield	1999	975	99	6/7	10/11
71 Canal St TS	Westerly	1951	750	75	8	2
28 Brown St	Warren	2010	750	99	9	12

Division 1-11, Page 2

Station Name	Town	Original Install Year	Inlet MAOP	Downstream MAOP	Overall Risk Ranking	Records Integrity Risk Ranking
30 Allens Ave (Manchester St) TS	Providence	1993	750	99	10	5
1085 Wallum Lake Rd TS	Burrillville	1971	750	99	11	4
DUKE (AGT) 4317 Diamond Hill Rd	Cumberland	1990	750	60	12	6

Prepared by or under the supervision of: Justin Zaccari

Division 1-12

Request:

Provide an update for the Wampanoag Trail Pipeline Replacement on Page 22, including the total costs and a construction timeline.

Response:

Preliminary engineering started in October 2022 and is expected to take nine to twelve months. Construction is anticipated to start in Spring of 2024 and to be completed in fall of 2025. The high-level estimated cost is $4.13 million; a detailed estimate of the cost will be performed when the engineering design is complete.

Division 1-13

Request:

For the year to year increases in Main Replacement (Proactive) (<16-inch) on Page 24, identify the principal cost drivers (in terms of % and in $) for the following:

(a) New contract impacts;

(b) Local paving requirements;

(c) Professional engineering; and

(d) Higher proportion of cast iron main replacement.

Also provide the overall average cost per mile installed.

Response:

The cost for the Proactive Main Replacement program for the CY 2023 9-month period is slightly lower than the budgeted cost for the same program in the FY 2023 ISR plan due to the shortened year. For the CY 2024 12-month period, the proposed cost is approximately $10 million greater than for the FY 2023 ISR budget. Impacts related to the itemized categories above are:

(a) Outside contractor and internal union costs are expected to increase by 2% - 3.5% resulting in approximately $1.5 million in additional cost.

(b) No new local paving requirements are expected in addition to those imposed following the curb-to-curb paving law enacted by the state in 2019.

(c) No new additional professional engineering expenses are expected in addition to those required as a result of the 2019 changes to R.I. Gen. Laws § 5-8-21.

(d) The proportion of cast iron replacement relative to bare steel is not expected to change substantially during the 21-month FY 2024 period.

Prepared by or under the supervision of: Phil LaFond

Division 1-13, page 2

The cost increase is also driven by 3 additional major factors:

1. **Cost of materials**

   The Company has not yet observed a significant increase in material cost expected due to the high inflation factor observed in other business sectors. It is expected that material costs could rise by up to 25%, resulting in approximately $0.85 million in additional cost for the 12-month CY 2024 period.

2. **Fuel costs**

   The cost of fuel is a major factor in the material cost for the Company's paving operations. A 20%, or $1.9 million, cost increase in paving has been factored into the cost increase for the 12-month CY 2024 period.

3. **Increase in miles abandoned**

   The remainder of the cost increase for the 12-month CY 2024 is due to the proposed increase in miles abandoned.

The overall cost per mile for this category for the 21-month FY 2024 period is $1.7 million.

Division 1-14

Request:

Provide the most current Gas Work Method procedure for the identification, evaluation and prioritization of distribution main segments for replacement.

Response:

Please see Attachment Division 1-14a for the most recent version of Gas Work Method ENG04030 "Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement", Rev. 7, Dated 02/01/2022.

Also see Attachment Division 1-14b for the referenced "DIMP Factors".

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:

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

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:

$$R = P \times C$$

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

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

Division 1-15

Request:

Provide a low/medium/high risk ranking by material of all remaining leak prone pipe inventory to date by city/town in the Rhode Island gas distribution system including cast iron, unprotected steel, ductile iron and Aldyl-A pipe.

Response:

Please see Attachment Division 1-15 for the Rhode Island analyzed Leak-prone pipe ("LPP") inventory separated by city/town and low/medium/high risk ranking. The Company does not currently have the entire LPP main inventory risk ranked. The analyzed inventory includes all segments which have been reviewed, had a project scoped out in the surrounding area, and assigned a priority score using the ENG04030 process. Cast iron main break leak data and steel corrosion leak data (as those are the heaviest weighing factors in the ENG04030 process) is reviewed on an annual basis and segments on which those leaks occur are analyzed to help grow this inventory.

RI Analyzed LPP Main Inventory - As of 11/15/2022
Mileage in Priority Tiers by Town
(Includes in progress segments until abandonment is completed)

Town	Mileage in Priorty Score Tiers			Total
	High Pr > 15	Medium 15 ≥ Pr ≥ 10	Low 10 > Pr	
Barrington	0.00	0.00	3.37	3.37
Bristol	1.02	3.05	1.78	5.85
Central Falls	0.00	1.45	6.54	7.99
Coventry	0.00	0.00	7.82	7.82
Cranston	5.93	9.27	21.64	36.84
Cumberland	0.51	2.34	4.69	7.54
East Greenwich	0.03	0.00	1.64	1.67
East Providence	2.92	4.18	11.48	18.58
Hopkinton	0.00	0.00	0.02	0.02
Johnston	0.89	1.88	13.25	16.02
Lincoln	1.60	1.36	4.24	7.20
Middletown	0.00	0.53	2.94	3.47
Narragansett	0.00	0.00	0.71	0.71
Newport	1.38	1.92	4.13	7.43
North Kingstown	0.00	0.00	3.06	3.06
North Providence	6.64	2.96	8.94	18.54
North Smithfield	1.32	0.85	3.66	5.83
Pawtucket	8.35	10.01	14.86	33.22
Providence	37.26	21.39	13.38	72.03
Smithfield	1.54	0.00	2.33	3.87
South Kingston	0.00	0.00	4.70	4.70
Warren	0.00	0.56	0.90	1.46
Warwick	2.48	4.70	34.09	41.27
West Warwick	0.00	0.00	4.03	4.03
Westerly	1.80	1.90	1.37	5.07
Woonsocket	3.13	4.68	14.78	22.59
Total	76.80	73.03	190.35	340.18

Division 1-16

Request:

Provide an updated list of all proactive main replacement, Public Works, Reliability, Reinforcement, Rehabilitation and Regulator Station projects and their current status for FY 2023. Please include installation miles, abandonment miles and number of services. Also include the start and abandonment date.

Response:

Please see the following attachments for the requested information:

- DIV 1-16-1: All Project Status, which includes all work packages being tracked in FY 2023.
- DIV 1-16-2: Regulator Station Installation Status, which provides additional detail for Regulator Station projects included on the All Project Status list.
- DIV 1-16-3: CISBOT Status, which provides additional detail for CISBOT projects included on the All Project Status list.
- DIV 1-16-4: Single Valve Bypass Status, which provides additional detail for Single Valve Bypass projects included on the All Project Status list.
- DIV 1-16-5: LP Relief Valve Status, which provides additional detail for LP Relief Valve projects included on the All Project Status list.

Main WO#	Plan Year	Project Status	Project Title	Town	Actual Start Date	Date Completed	Program	Funding Code	#Svcs- Project Scope	Project Scope Est. Install Footage	Footage Installed in FY22 or Prior	Actual Installed Footage FY23	Estimated Abandonment Footage	Actual Abandonment Footage *(once complete)*
90000224961	FY23	FCOMP	Wood St, BST	BST	5/12/2022	7/13/2022	Reliability	CRCC111	0	3020	0	3119	0	0
90000220576	FY23	FCOMP	1235-1279 Wampanoag Trl, EPV	EPV	4/14/2022	5/3/2022	Reliability	CRCC111	0	1100	0	1220	0	0
90000216895	FY22	COMP	Green End Av, MDT	MDT	2/23/2022	6/10/2022	Reliability	CRCC111	0	3000	1922	1028	0	0
90000207716	FY23	COMP	S County Trl, NKS	NKS	5/16/2022	6/24/2022	Reliability	CRCC111	0	685	0	775	0	0
90000216932	FY23	ABANDONED	Franklin St, WAN	WAN	3/28/2022	11/1/2022	Reliability	CRCC111	21	2440	520	2091	2865	2865
90000212105	FY22	INPRG	Plainfield @ Simmmonsville	JOH	7/6/2022		Reliability	CRCC111	0	0	0	0	0	0
90000220556	FY23	INPRG	Cobble Hill Rd LNC	LNC	4/21/2022		Reliability	CRCC111	12	8100	0	7766	1050	1050
90000220506	FY23	INPRG	Third Av WSO	WSO	9/12/2022		Reliability	CRCC111	69	3960	0	3881	3590	3590
90000216931	FY22	INPRG	Ten Rod Rd NKS	NKS	10/17/2022		Reliability	CRCC111	6	1050	0	656	1050	1050
90000180674	FY19	WSTOP	Old Park Ave, CRA	CRA	8/22/2018		Reliability	CRCC111	0	1145	1145		0	0
90000209570	FY21	WSTOP	Franklin St, WLY	WLY	8/18/2021		Reliability	CRCC111	0	450	75	0	0	0
90000180671	FY23	DISPATCH	Rathbun St, WSO	WSO			Reliability	CRCC111	37	1530	0		335	335
90000224933	FY23	WSCHD	220-285 Wampanoag Trl, EPV	EPV			Reliability	CRCC111	0	330	0		0	0
90000225628	FY23	WSCHD	300-400 Wampanoag Trl, EPV	EPV			Reliability	CRCC111	0	900	0		0	0
90000216897	FY22	AWPER	Harris Av PVD	PVD			Reliability	CRCC111	6	970	0		0	0
90000224894	FY23	AWPER	Elmwood Av, WWK	WWK			Reliability	CRCC111	4	1000	0		0	0
90000180116	FY22	NRTD	Central Av PAW	PAW			Reliability	CRCC111	0	2000	0		0	0
90000224888	FY23	PENDING	Hayward St, PAW	PAW			Reliability	CRCC111	0	0	0	0	0	0
90000207957	FY21	CANCELED	Memorial Blvd NPR	NPR			Reliability	CRCC111	0	2080	0		7030	0

Main WO#	Plan Year	Project Status	Project Title	Town	Actual Start Date	Date Completed	Program	Funding Code	#Svcs- Project Scope	Project Scope Est. Install Footage	Footage Installed in FY22 or Prior	Actual Installed Footage FY23	Estimated Abandonment Footage	Actual Abandonment Footage *(once complete)*
90000208175	FY21	FCOMP	Woodland St @ Smithfield Ave	LNC	7/29/2021	5/11/2022	Reliability	C084288	0	0	0	0	0	0
90000218144	FY22	FCOMP	Pawtucket Ave	EPV	12/3/2021	9/2/2022	Reliability	CRCC401	2	313	313	0	270	270
90000220362	FY22	FCOMP	Scott RD Take Station	CLD	6/16/2022	7/16/2022	Reliability	C084983	0	0	0	0	0	0
90000216520	FY23	FCOMP	Scott Rd Test Pits CLD	CLD	6/16/2022	7/16/2022	Reliability	C079174	0	0	0	0	0	0
90000204283	FY21	FCOMP	Smith @ Sunset NPV	NPV	11/3/2022	11/8/2022	Reliability	CRIC213	0	0	0		0	0
90000207467	FY23	FCOMP	E Main @ Turner Rd, MDT	MDT	7/27/2022	10/27/2022	Reliability	CRIC402	0	0	0		0	0
90000225642	FY23	FCOMP	Cobble Hill Rd @ Louisquissett Pike-Header LNC	LNC	9/7/2022	10/7/2022	Reliability	CRIC402	0	0	0	0	0	0
90000205544	FY21	COMP	French Town Rd	EGW	6/14/2021	8/23/2022	Reliability	CRIC402	0	0	0	0	0	139
90000208179	FY22	COMP	Bailey @ Ballou	WSO	10/6/2021	5/6/2022	Reliability	CRIC402	0	0	0	0	0	0
90000208671	FY22	COMP	St James Relief Valve WSO	WSO	6/16/2022	7/19/2022	Reliability	C084288	0	0	0	0	0	0
90000220363	FY22	COMP	Dean St SMF	SMF	9/29/2021	4/27/2022	Reliability	CRCC401	1	147	147	0	0	0
90000217567	FY23	COMP	Warwick Ave @ W Shore Rd, WWK	WWK	5/10/2022	5/10/2022	Reliability	CRIC402	0	0	0	12	0	12
90000217548	FY23	COMP	6 Long Ln, NKS	NKS	6/28/2022	6/28/2022	Reliability	CRIC402	0	0	0	12	0	5
90000207442	FY21	COMP	747 Bullocks Point EPV	EPV	4/18/2022	4/25/2022	Reliability	CRIC402	0	0	0	14	0	1
90000144235	FY23	COMP	High @ Fountain Valve Replacement WSO	WSO	10/3/2022	10/13/2022	Reliability	CRIC402	0	0	0	0	0	4
90000145110	FY23	ABANDONED	Pettis @ North Main PVD	PVD	6/1/2022	8/23/2022	Reliability	CRIC402	0	50	0	0	0	0
90000225776	FY23	ABANDONED	Allendale Av Bridge, JOH	JOH	7/19/2022	7/20/2022	Integrity	CRRC301	0	0	0	0	0	0
90000204096	FY22	ABANDONED	816 Middle Rd	EGW	6/13/2022	9/29/2022	Reliability	CRIC402	0	0	0	227	0	0
90000219643	FY23	ABANDONED	Martin @ Dodge, East Providence	EPV	7/21/2022	10/5/2022	Reliability	CRIC402	0	0	0	0	0	0
90000215589	FY23	INPRG	Kenwood @ Cass, WSO	WSO	11/3/2022		Reliability	CRIC402	0	0	0	0	0	0
90000207499	FY21	INPRG	Waterman @ Whitman SMF	SMF	6/7/2022		Reliability	CRIC402	0	0	0	0	0	0
90000209055	FY23	INPRG	Cowesett @ Quaker, WWW	WWW	5/15/2022		Reliability	C085181	0	90	0	0	75	0
90000181673	FY23	INPRG	RIS071 / RIS089-Willet @ Forbes EPV	EPV	7/5/2022		Reliability	C077246	0	0	0	952	0	0
90000227909	FY23	INPRG	Old Mill Ln ECO-RASTER Project PSM	PSM	8/16/2022		Reliability	C082835	0	0	0	0	0	0
90000194780	FY22	DISPATCH	Rt 10 S Offramp @ Union Av PVD	PVD			Integrity	CRFN224	0	385	0	0	385	0
90000144219	FY23	DISPATCH	Station @ Pond (RIS-017) CRA	CRA			Reliability	CRIC402	0	0	0	0	0	0
90000217555	FY23	DISPATCH	Mayfield Rd @ Oakland Av, CRA	CRA			Reliability	CRIC402	0	0	0	0	0	0
90000228513	FY23	DISPATCH	Sunbury St PVD	PVD			Reliability	CRCC401	4	420	0	0	0	0
90000208691	FY23	WSCHD	Wolcott @ St. Georges MDT	MDT			Reliability	C084288	0	0	0	0	0	0
90000208982	FY21	AWPER	Thames @ Washington Sq 12in Valve	NPR			Integrity	C085142	0	0	0	0	0	0
90000208968	FY21	AWPER	Thames @ W Narragansett 12in Valve NPR	NPR			Integrity	C085142	0	0	0	0	0	0
90000209009	FY21	AWPER	Rhode Island @ Champlin 6in Valve	NPR			Integrity	C085142	0	0	0	0	0	0
90000222517	FY23	AWPER	Waterman Greystone Outlet Valve Replacement NPV	NPV			Reliability	CRIC213	0	0	0	0	0	0
90000220806	FY23	AWPER	Bald Hill Rd-East Av, WWK	WWK			Reliability	CRCC401	10	3580	0	0	3444	0
90000173914	FY21	NRTD	Division St Bridge Brackets PAW	PAW			Integrity	CRRC301	0	0	0	0	0	0
90000207468	FY21	NRTD	Carroll Ave @ Ocean NPR	NPR			Reliability	CRIC402	0	0	0	0	0	0
90000210499	FY22	NRTD	Atwells Av PVD	PVD			Integrity	C081157	42	1430	0	0	2740	0
90000221104	FY23	NRTD	120-262 Tuckerman Av, MDT	MDT			Integrity	CRCC455	112	8300	0	0	300	0
90000204089	FY21	NRTD	Park @ Maple CRA	CRA			Reliability	CRIC402	0	0	0	0	0	0
90000118390	FY23	PENDING	Maple Av MDT	MDT			Integrity	CON0034	0	2785	0	0	2440	0
90000131590	FY23	PENDING	Cowesett @ Quaker, WWW	WWW			Reliability	CRIC402	0	0	0	0	0	0
90000207469	FY23	PENDING	3362 Kingstown Rd (Waltes Corner), NKS	NKS			Reliability	CRIC402	0	0	0	0	0	0
90000217562	FY23	PENDING	Dyer @ Pine St, PVD	PVD			Reliability	CRIC402	0	0	0	0	0	0
90000220913	FY23	PENDING	Cannon St	CRA			Reliability	CRCC401	0	0	0	0	0	0
90000224932	FY23	PENDING	Roger Williams Av, EPV	EPV			Reliability	CRCC401	0	0	0	0	0	0
90000184270	FY23	PENDING	Petteys Av - LINING, PVD	PVD			Integrity	C078189	0	0	0	0	0	0
90000209541	FY23	PENDING	Old River Rd, LNC	LNC			Reliability	CRCC401	0	0	0	0	0	0
90000229980	FY23	PENDING	Wolcott Ave, MDT	MDT			CSC	CRCC455	0	0	0	0	0	0
90000217564	FY23	RECEIVED	Stony Ln @ Rt 2, NKS	NKS			Reliability	CRIC402	0	0	0	0	0	0
90000228516	FY24	RECEIVED	Mason @ Asylum WSO	WSO			Reliability	CRIC213	0	0	0	0	0	0
90000217566	FY23	CANCELED	W Main @ Oliphant, MDT	MDT			Reliability	CRIC402	0	0	0		0	0
90000204095	FY23	CANCELED	Regulator Replacement Post @ Byron RIS-036, WWK	WWK			Reliability	CRIC402	0	0	0		0	0

Revised Attachment Division 1-16-1

1-16-1 All Project Status

Main WO#	Plan Year	Project Status	Project Title	Town	Actual Start Date	Date Completed	Program	Funding Code	#Svcs- Project Scope	Project Scope Est. Install Footage	Footage Installed in FY22 or Prior	Actual Installed Footage FY23	Estimated Abandonment Footage	Actual Abandonment Footage *(once complete)*
90000204644	FY21	FCOMP	Woodbine St, PAW	PAW	5/18/2020	3/4/2022	Integrity	CRCC207	19	808	808	0	840	840
90000204753	FY21	FCOMP	Myrtle St, PAW	PAW	8/11/2021	3/22/2022	Integrity	CRCC207	17	0	0	0	630	630
90000210558	FY22	FCOMP	Lyman Ave	NPV	3/29/2021	3/18/2022	Integrity	CRCC207	81	4126	4126	0	400	400
90000204629	FY23	FCOMP	131-244 Pequot Av, WWK	WWK	4/4/2022	7/14/2022	Integrity	CRCC203	39	2860	0	3004	2760	2760
90000219674	FY23	FCOMP	Mason St, WAN	WAN	6/3/2022	7/29/2022	Integrity	CRCC203	16	1015	0	1022	1015	1015
90000217999	FY23	FCOMP	74-131 Pequot Av WWK	WWK	4/28/2022	7/14/2022	Integrity	CRCC203	11	900	0	926	900	900
90000189861	FY22	FCOMP	RIDOT Park Ave RR Bridge No 922 HP	CRA	5/18/2021	5/12/2022	CSC	CRCC307	0	218	0	0	302	302
90000200332	FY21	FCOMP	RIDOT Park Ave RR Bridge No 922	CRA	5/18/2021	5/12/2022	CSC	CRCC307	0	404	0	0	228	228
90000208175	FY21	FCOMP	Woodland St @ Smithfield Ave	LNC	7/29/2021	5/11/2022	Reliability	C084288	0	0	0	0	0	0
90000212629	FY22	FCOMP	Holland St, CRA	CRA	6/25/2021	4/29/2022	Integrity	CRCC207	34	2330	2330	0	2045	2045
90000211112	FY22	FCOMP	Beverage Hill Ave, PAW	PAW	7/1/2021	4/25/2022	Integrity	CRCC207	56	3267	3267	0	2955	2955
90000212444	FY22	FCOMP	380-433 Lonsdale Ave	PAW	8/2/2021	8/4/2022	Integrity	CRCC207	76	3287	3287	0	3390	3390
90000211182	FY22	FCOMP	Carver St, PAW	PAW	4/27/2021	5/16/2022	Integrity	CRCC207	41	2230	2230	0	2370	2370
90000218144	FY22	FCOMP	Pawtucket Ave	EPV	12/3/2021	9/2/2022	Reliability	CRCC401	2	313	313	0	270	270
90000219489	FY22	FCOMP	QDC Mill Creek Railyard	NKS	8/20/2021	5/18/2022	CSC	CRCC307	0	3152	3152	0	2764	2764
90000217120	FY23	FCOMP	Standish Ave CRA	CRA	8/2/2022	9/8/2022	Integrity	CRCC207	5	265	0	285	265	265
90000217994	FY23	FCOMP	1-101 Greeley Ave WWK	WWK	4/4/2022	5/18/2022	Integrity	CRCC203	21	2135	0	2180	2135	2135
90000220362	FY22	FCOMP	Scott RD Take Station	CLD	6/16/2022	7/16/2022	Reliability	C084983	0	0	0	0	0	0
90000218350	FY23	FCOMP	Nimitz Rd, EPV	EPV	5/11/2022	8/12/2022	Integrity	CRCC207	69	3075	0	3045	3305	3305
90000218379	FY23	FCOMP	Bell Av, EPV	EPV	4/28/2022	6/24/2022	Integrity	CRCC207	13	635	0	710	540	540
90000219201	FY23	FCOMP	Sandlewood Av, WWK	WWK	8/10/2022	9/8/2022	Integrity	CRCC203	14	500	0	719	520	520
90000224271	FY23	FCOMP	94-188 Legion Wy - CISBOT, CRA	CRA	8/16/2022	9/26/2022	Integrity	CRCC205	0	0	0	0	0	0
90000219212	FY23	FCOMP	99-129 Brightridge Av EPV	EPV	5/9/2022	8/15/2022	Integrity	CRCC207	35	1925	0	2106	2195	2195
90000225851	FY23	FCOMP	RIDOT Cottrell Bridge WLY	WLY	9/14/2022	10/5/2022	CSC	CRCC307	0	233	0	0	189	189
90000216520	FY23	FCOMP	Scott Rd Test Pits CLD	CLD	6/16/2022	7/16/2022	Reliability	C079174	0	0	0	0	0	0
90000204283	FY21	FCOMP	Smith @ Sunset NPV	NPV	11/3/2022	11/8/2022	Reliability	CRIC213	0	0	0		0	0
90000207467	FY23	FCOMP	E Main @ Turner Rd, MDT	MDT	7/27/2022	10/27/2022	Reliability	CRIC402	0	0	0		0	0
90000227017	FY23	FCOMP	Pleasant St, PAW	PAW	10/13/2022	10/27/2022	CSC	CRCC306	2	0	0		188	188
90000218484	FY22	FCOMP	Rt.6/Rt.10 Interchange Reconstruction	PVD	9/1/2022	10/6/2022	CSC	CRCC307	0	700	459	83	680	680
90000220948	FY23	FCOMP	1-45 Bay View Av BST	BST	8/4/2022	10/28/2022	Integrity	CRCC206	16	705	0	700	750	750
90000220900	FY23	FCOMP	Long St, WWK	WWK	8/5/2022	10/18/2022	Integrity	CRCC203	16	1205	0	1346	1205	1205
90000211231	FY23	FCOMP	Oak St, WLY	WLY	4/25/2022	10/7/2022	Integrity	CRCC203	0	645	0	721	645	645
90000221982	FY23	FCOMP	RIDOT West Natick Rd Bridge WWK	WWK	4/25/2022	10/11/2022	CSC	CRCC307	2	126	0	262	130	130
90000228019	FY23	FCOMP	Cottrell Bridge Betterment (Westerly Bradford Rd) WLY	WLY	9/14/2022	10/5/2022	CSC	CRCC306	0	904	0		0	0
90000225642	FY23	FCOMP	Cobble Hill Rd @ Louisquissett Pike-Header LNC	LNC	9/7/2022	10/7/2022	Reliability	CRIC402	0	0	0	0	0	0
90000224961	FY23	FCOMP	Wood St, BST	BST	5/12/2022	7/13/2022	Reliability	CRCC111	0	3020	0	3119	0	0
90000220576	FY23	FCOMP	1235-1279 Wampanoag Trl, EPV	EPV	4/14/2022	5/3/2022	Reliability	CRCC111	0	1100	0	1220	0	0
90000207569	FY21	COMP	Metcalf St PVD	PVD	1/4/2020	9/29/2022	CSC	CRCC306	118	6716	6716	0	7135	7135
90000142626	FY22	COMP	392-498 Douglas Av, PVD	PVD	8/30/2021	9/30/2022	Integrity	CRCC207	47	3130	3130	0	3020	3100
90000211129	FY22	COMP	Taft St	PAW	8/18/2021	3/3/2022	Integrity	CRCC207	9	498	498	0	520	520
90000194429	FY20	COMP	Fairmount St, WSO	WSO	5/22/2019	3/21/2022	Integrity	CRCC207	3	3809	3809	0	1020	2732
90000185694	FY20	COMP	Sessions St, PVD	PVD	8/16/2019	4/25/2022	Integrity	CRCC207	15	1054	1054	0	1848	1830
90000194356	FY22	COMP	Felix St, PVD	PVD	7/19/2021	8/24/2022	Integrity	CRCC207	33	1838	1838	0	1570	1838
90000143075	FY21	COMP	1207-1275 Elmwood Av, PVD	PVD	10/22/2020	7/14/2022	Integrity	CRCC207	67	3105	3105	0	3050	3105
90000185679	FY21	COMP	1315-1477 Broad St, PVD	PVD	8/4/2020	6/8/2022	Integrity	CRCC207	32	2714	2714	0	2325	2627
90000209032	FY21	COMP	Great Rd, NSF	NSF	11/29/2021	6/8/2022	CSC	CRCC306	6	288	288	0	210	218
90000202501	FY21	COMP	RIDOT Division St Bridge	EGW	7/13/2020	7/5/2022	CSC	CRCC307	0	480	0	460	485	763
90000210923	FY22	COMP	Taft Ave PVD	PVD	8/30/2021	4/22/2022	CSC	CRCC306	28	1066	1066	0	1137	1137
90000211226	FY21	COMP	S Main St PVD	PVD	11/18/2020	8/16/2022	CSC	CRCC306	11	2197	2197	0	2075	2108
90000205544	FY21	COMP	French Town Rd	EGW	6/14/2021	8/23/2022	Reliability	CRIC402	0	0	0	0	0	139
90000211228	FY22	COMP	N Main St PVD	PVD	3/29/2021	8/16/2022	CSC	CRCC306	17	2629	2629	0	2600	2600
90000194373	FY21	COMP	Terrace Av, PVD	PVD	11/17/2020	8/19/2022	Integrity	CRCC207	65	3046	3046	0	2950	2950
90000210929	FY22	COMP	Ballou St	WSO	8/30/2021	5/17/2022	Integrity	CRCC207	54	3213	3213	0	3000	3000
90000211636	FY22	COMP	Ledge St	PVD	4/26/2021	6/14/2022	Integrity	CRCC207	140	5793	5793	0	5865	5865
90000155245	FY22	COMP	Herbert St, PVD	PVD	8/27/2021	7/6/2022	Integrity	CRCC203	17	1236	1236	0	1260	1200
90000212618	FY22	COMP	Brown Av, NPV	NPV	4/9/2021	4/28/2022	Integrity	CRCC207	28	1258	1258	0	1295	1295
90000208179	FY22	COMP	Bailey @ Ballou	WSO	10/6/2021	5/6/2022	Reliability	CRIC402	0	0	0	0	0	0
90000212820	FY21	COMP	2-68 Homewood Ave	NPV	9/17/2021	8/31/2022	Integrity	CRCC207	55	3089	3089	0	2630	2630
90000208671	FY22	COMP	St James Relief Valve WSO	WSO	6/16/2022	7/19/2022	Reliability	C084288	0	0	0	0	0	0
90000219921	FY22	COMP	Mountain Ave, WLY	WLY	3/22/2022	4/28/2022	CSC	CRCC306	8	1200	706	522	1203	1203
90000220363	FY22	COMP	Dean St SMF	SMF	9/29/2021	4/27/2022	Reliability	CRCC401	1	147	147	0	0	0
90000217815	FY22	COMP	RIDOT Rte 5 Bridge	WWK	9/13/2021	7/5/2022	CSC	CRCC307	0	585	0	0	533	533
90000211809	FY22	COMP	Sabin St	WWK	11/16/2021	6/28/2022	Integrity	CRCC203	44	2760	1492	1520	2760	2937
90000211822	FY22	COMP	Owens St	WWK	4/4/2022	5/18/2022	Integrity	CRCC203	18	1320	0	1373	1400	1340
90000224361	FY22	COMP	Livingston St PVD	PVD	4/25/2022	7/1/2022	CSC	CRCC307	1	120	0	177	110	150
90000220813	FY23	COMP	Old Forge Rd BRG	BRG	4/13/2022	5/20/2022	Integrity	CRCC203	6	370	0	383	370	381
90000210865	FY23	COMP	Sweet St SMF	SMF	4/4/2022	5/5/2022	Integrity	CRCC203	8	645	0	671	645	645

1-16-1 All Project Status

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90000211467	FY23	COMP	Victory Ave WWW	WWW	5/5/2022	6/3/2022	Integrity	CRCC203	7	615	0	592	635	635
90000220812	FY23	COMP	Christine Dr, BRG	BRG	4/11/2022	4/22/2022	Integrity	CRCC203	3	290	0	304	290	295
90000210887	FY23	COMP	Russell Ln, SMF	SMF	4/12/2022	5/6/2022	Integrity	CRCC203	9	885	0	979	925	905
90000211834	FY23	COMP	Viewesta Rd, WWK	WWK	4/8/2022	4/22/2022	Integrity	CRCC203	2	180	0	180	180	188
90000218042	FY23	COMP	Smith St, LNC	LNC	3/21/2022	6/27/2022	Integrity	CRCC207	37	2445	995	1574	2445	2445
90000223560	FY23	COMP	Smithfield Ave PVD	PVD	5/31/2022	6/24/2022	CSC	CRCC308	0	300	0	336	240	336
90000219681	FY23	COMP	Charles Av, WLY	WLY	6/2/2022	7/27/2022	Integrity	CRCC203	13	1040	0	1066	1040	1050
90000224287	FY23	COMP	1092-1247 Chalkstone Av - CISBOT, PVD	PVD	6/15/2022	8/12/2022	Integrity	CRCC205	0	0	0	0	0	0
90000220903	FY23	COMP	Holland Av EPV	EPV	5/2/2022	6/29/2022	Integrity	CRCC203	12	630	0	761	630	760
90000215877	FY23	COMP	Cornell Av EPV	EPV	5/5/2022	7/14/2022	Integrity	CRCC207	9	400	0	410	380	380
90000220957	FY23	COMP	Ferncliff Av NPV	NPV	8/1/2022	9/7/2022	Integrity	CRCC207	12	615	0	641	560	635
90000225655	FY23	COMP	Sylvian Ct, CFL	CFL	5/18/2022	5/18/2022	CSC	CRCC306	0	0	0	0	11	11
90000217567	FY23	COMP	Warwick Ave @ W Shore Rd, WWK	WWK	5/10/2022	5/10/2022	Reliability	CRIC402	0	0	0	12	0	12
90000220845	FY23	COMP	Spencer Rd, SMF	SMF	3/30/2022	6/2/2022	Integrity	CRCC203	4	460	0	471	310	310
90000226408	FY23	COMP	RIDOT Rte 5- Greenwich Ave	WWK	3/28/2022	5/9/2022	CSC	CRCC307	0	425	160	322	983	458
90000226800	FY23	COMP	44 Paul St, PVD	PVD	5/18/2022	6/23/2022	CSC	CRCC312	7	395	0	374	325	325
90000201184	FY23	COMP	Tobey St (2 of 2) - CISBOT, PVD	PVD	5/2/2022	6/21/2022	Integrity	CRCC205	0	0	0	0	0	0
90000226187	FY23	COMP	E Knowlton St EPV	EPV	7/11/2022	7/11/2022	CSC	CRCC306	3	172	0	160	165	166
90000217548	FY23	COMP	6 Long Ln, NKS	NKS	6/28/2022	6/28/2022	Reliability	CRIC402	0	0	0	12	0	5
90000229823	FY23	COMP	Thackery St PVD	PVD	6/29/2022	6/29/2022	Integrity	CRCC210	0	0	0	0	850	850
90000228664	FY23	COMP	Oregon St @ Oriental St PVD	PVD	7/27/2022	8/11/2022	CSC	CRCC308	3	185	0	197	540	540
90000226603	FY23	COMP	Roselawn Av NSF	NSF	8/10/2022	8/10/2022	CSC	CRCC306	0	523	0	0	523	523
90000207442	FY21	COMP	747 Bullocks Point EPV	EPV	4/18/2022	4/25/2022	Reliability	CRIC402	0	0	0	14	0	1
90000211306	FY23	COMP	Indian Rd EPV	EPV	5/5/2022	7/15/2022	Integrity	CRCC203	27	1565	0	1578	1565	1565
90000228710	FY23	COMP	Halsey St NPR	NPR	8/25/2022	9/12/2022	CSC	CRCC307	0	250	0	200	250	254
90000144235	FY23	COMP	High @ Fountain Valve Replacement WSO	WSO	10/3/2022	10/13/2022	Reliability	CRIC402	0	0	0	0	0	4
90000155107	FY21	COMP	Union Av, PVD	PVD	10/26/2020	11/1/2022	Integrity	CRCC207	54	1891	1891	0	1830	1891
90000230189	FY23	COMP	Collyer St PVD	PVD	9/8/2022	10/7/2022	CSC	CRCC307	1	545	0	340	730	730
90000216895	FY22	COMP	Green End Av, MDT	MDT	2/23/2022	6/10/2022	Reliability	CRCC111	0	3000	1922	1028	0	0
90000207716	FY23	COMP	S County Trl, NKS	NKS	5/16/2022	6/24/2022	Reliability	CRCC111	0	685	0	775	0	0
90000212647	FY22	ABANDONED	Garden St CRA	CRA	4/14/2021	4/19/2022	Integrity	CRCC207	14	630	630	0	840	840
90000204620	FY22	ABANDONED	2790-3055 W Shore Rd, WWK	WWK	7/28/2021	9/28/2022	Integrity	CRCC203	56	5883	5883	0	5170	5170
90000155652	FY22	ABANDONED	3073-3416 West Shore Rd	WWK	9/24/2021	9/28/2022	Integrity	CRCC203	46	3730	2741	1275	3785	3785
90000211546	FY22	ABANDONED	1-75 East Ave PAW	PAW	6/21/2021	10/5/2022	Integrity	CRCC206	6	875	811	222	2745	2745
90000211188	FY22	ABANDONED	Cherry St, PAW	PAW	9/14/2021	4/27/2022	Integrity	CRCC207	59	2620	2620	25	2685	2685
90000194305	FY22	ABANDONED	Wannamoisett Rd	EPV	6/3/2021	10/5/2022	Integrity	CRCC207	71	4471	4471	0	4505	4505
90000194304	FY22	ABANDONED	Vineyard Ave	EPV	6/3/2021	10/5/2022	Integrity	CRCC207	53	3520	2409	1152	4225	4225
90000219454	FY22	ABANDONED	Lisbon St	PVD	9/27/2021	8/15/2022	Integrity	CRCC207	112	4017	4017	0	4200	4200
90000218412	FY23	ABANDONED	Case St, EPV	EPV	5/5/2022	9/28/2022	Integrity	CRCC207	7	270	0	383	270	270
90000218415	FY23	ABANDONED	Bishop Av, EPV	EPV	5/14/2022	9/21/2022	Integrity	CRCC207	12	1260	0	1387	1260	1260
90000145110	FY23	ABANDONED	Pettis @ North Main PVD	PVD	6/1/2022	8/23/2022	Reliability	CRIC402	0	50	0	0	0	0
90000225776	FY23	ABANDONED	Allendale Av Bridge, JOH	JOH	7/19/2022	7/20/2022	Integrity	CRRC301	0	0	0	0	0	0
90000218482	FY23	ABANDONED	Ferris Av, EPV	EPV	6/2/2022	9/28/2022	Integrity	CRCC207	15	945	0	978	960	960
90000218036	FY23	ABANDONED	Abbott St CLD	CLD	4/4/2022	9/15/2022	Integrity	CRCC207	36	3105	0	3259	3105	3105
90000220950	FY23	ABANDONED	Appleton St CRA	CRA	6/21/2022	10/4/2022	Integrity	CRCC207	44	2120	0	2084	2120	2120
90000204628	FY23	ABANDONED	Namquid Dr, WWK	WWK	5/26/2022	8/23/2022	Integrity	CRCC203	43	5855	0	5680	6615	6615
90000227397	FY23	ABANDONED	55-136 Mt. Hope Av, BST	BST	6/17/2022	8/24/2022	CSC	CRCC312	20	1150	0	1124	1150	1150
90000226657	FY23	ABANDONED	Smithfield Av @ Oakdale Av, PAW	PAW	6/13/2022	7/8/2022	CSC	CRCC308	1	156	0	219	148	148
90000229103	FY23	ABANDONED	156 Washington St CFL	CFL	8/30/2022	8/30/2022	CSC	CRCC312	0	33	0		44	44
90000175690	FY20	ABANDONED	Vinton St, PVD	PVD	8/2/2019	11/8/2022	Integrity	CRCC207	111	1056	1056	0	5695	5695
90000211538	FY22	ABANDONED	Fenner St, PAW	PAW	10/1/2021	10/20/2022	Integrity	CRCC207	57	2708	2708	0	3585	3585
90000204096	FY22	ABANDONED	816 Middle Rd	EGW	6/13/2022	9/29/2022	Reliability	CRIC402	0	0	0	227	0	0
90000215080	FY23	ABANDONED	1-87 Packard St CRA	CRA	6/24/2022	11/2/2022	Integrity	CRCC207	97	3965	0	4264	4365	4365
90000220960	FY23	ABANDONED	Forest Av CRA	CRA	6/23/2022	10/12/2022	Integrity	CRCC207	63	3870	0	3967	3855	3855
90000219187	FY23	ABANDONED	111-320 Greeley Av, WWK	WWK	8/11/2022	10/17/2022	Integrity	CRCC203	24	5250	0	4954	5210	5110
90000220909	FY23	ABANDONED	Grover St, NPV	NPV	4/18/2022	11/3/2022	Integrity	CRCC207	20	680	0	662	680	680
90000220867	FY23	ABANDONED	Wood St, WWK	WWK	7/25/2022	10/25/2022	Integrity	CRCC203	83	5280	0	5688	5280	5280
90000225745	FY23	ABANDONED	Bicentennial Wy, NPV	NPV	6/2/2022	10/28/2022	Integrity	CRCC203	44	2035	0	2176	2035	2035
90000230701	FY23	ABANDONED	2670-2794 Warwick Av WWK	WWK	9/7/2022	9/27/2022	CSC	CRCC306	8	0	0	0	0	0
90000219643	FY23	ABANDONED	Martin @ Dodge, East Providence	EPV	7/21/2022	10/5/2022	Reliability	CRIC402	0	0	0	0	0	0
90000185696	FY22	ABANDONED	392-550 Valley St	PVD	8/30/2021	11/2/2022	Integrity	CRCC207	18	3648	703	0	3485	3485
90000216932	FY23	ABANDONED	Franklin St, WAN	WAN	3/28/2022	11/1/2022	Reliability	CRCC111	21	2440	520	2091	2865	2865
90000226385	FY23	INPRG	1640 Mineral Spring Av NPV	NPV	10/24/2022		Reliability	CRCC225	0	174	0	155	181	0
90000211435	FY22	INPRG	1-34 Central Av PAW	PAW	10/17/2022		Integrity	CRCC206	16	2415	0	1729	2750	0
90000218016	FY23	INPRG	336-642 Allens Av PVD	PVD	10/20/2022		Integrity	CRCC204	5	565	0	639	4775	0
90000218019	FY23	INPRG	434-642 Allens Av PVD	PVD	11/2/2022		Integrity	CRCC204	4	335	0	330	4710	0
90000220861	FY22	INPRG	Meadowbrook Dr	CLD	10/13/2022		Integrity	CRCC203	11	905	0	961	905	0
90000219276	FY23	INPRG	Maple St, WSO	WSO	10/18/2022		Integrity	CRCC207	8	545	0	623	545	0

1-16-1 All Project Status

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90000211208	FY23	INPRG	Harrison St, PAW	PAW	11/9/2022		Integrity	CRCC207	43	2680	0	0	2925	0
90000223205	FY23	INPRG	Central Av, EPV	EPV	10/20/2022		Integrity	CRCC207	94	3830	0	0	3585	0
90000215589	FY23	INPRG	Kenwood @ Cass, WSO	WSO	11/3/2022		Reliability	CRIC402	0	0	0	0	0	0
90000226942	FY23	INPRG	Russell Av, EPV	EPV	10/11/2022		CSC	CRCC306	9	410	0	404	416	0
90000092282	FY23	INPRG	Eldridge St CRA	CRA	11/1/2022		Integrity	CRCC207	44	2070	0	0	2245	0
90000229127	FY23	INPRG	Normandy Dr WWK	WWK	10/12/2022		Integrity	CRCC210	42	2975	0	2963	3290	0
90000228717	FY23	INPRG	Diamond Hill Rd, WWK	WWK	10/11/2022		CSC	CRCC306	44	3825	0	2593	3825	0
90000230318	FY23	INPRG	203-294 Governor St, PVD	PVD	10/26/2022		CSC	CRCC312	9	485	0	538	660	0
90000207499	FY21	INPRG	Waterman @ Whitman SMF	SMF	6/7/2022		Reliability	CRIC402	0	0	0	0	0	0
90000194355	FY22	INPRG	Branch Av, PVD	PVD	10/21/2021		Integrity	CRCC207	33	3210	2622	0	3180	0
90000155230	FY21	INPRG	Dean St, PVD	PVD	8/6/2020		Integrity	CRCC207	54	3752	3752	0	4260	0
90000209097	FY21	INPRG	Althea St, PVD	PVD	12/11/2020		Integrity	CRCC210	6	682	682	0	705	0
90000194428	FY22	INPRG	Blackstone St, WSO	WSO	7/16/2021		Integrity	CRCC207	24	2294	2294	0	2265	0
90000185662	FY22	INPRG	Memorial Blvd NPR	NPR	9/26/2022		Integrity	CRCC207	9	2410	0	2454	2460	0
90000210246	FY22	INPRG	Ernest St, PVD	PVD	8/27/2021		Integrity	CRCC203	4	687	687	0	3630	0
90000210486	FY22	INPRG	Butler St, CFL	CFL	11/29/2021		Integrity	CRCC207	78	3585	0	3599	3435	0
90000142840	FY22	INPRG	Haven Ave CRA	CRA	5/15/2021		Integrity	CRCC207	83	6006	6006	0	6740	0
90000211756	FY22	INPRG	Hartford Av PVD	PVD	8/22/2022		Integrity	CRCC207	38	3295	0	3205	3410	0
90000211854	FY22	INPRG	Waterman Ave NPV	NPV	7/1/2021		Integrity	CRCC207	67	1833	1833	0	3170	0
90000211548	FY22	INPRG	Summit Ave	NSF	11/3/2021		Integrity	CRCC207	16	610	310	0	630	0
90000204642	FY22	INPRG	Slade St PAW	PAW	9/24/2021		Integrity	CRCC207	30	1473	1473	0	1495	0
90000210771	FY22	INPRG	Winrooth Av PVD	PVD	4/25/2022		Integrity	CRCC207	72	2485	0	2407	3100	0
90000210947	FY22	INPRG	Willow Ave	WSO	6/9/2021		Integrity	CRCC207	91	4332	4332	0	5090	0
90000211875	FY21	INPRG	Waterman Ave NPV	SMF	7/23/2021		Integrity	CRCC207	54	1865	1865	0	6080	0
90000212438	FY21	INPRG	Smithfield Rd	NSF	10/28/2021		Integrity	CRCC207	61	4445	4235	690	6815	0
90000207983	FY22	INPRG	RIDOT Reservoir Ave Bridge	PVD	6/7/2021		CSC	CRCC307	2	729	0	0	828	0
90000214933	FY22	INPRG	211-670 Woonasquatucket Av NPV	NPV	6/17/2022		Integrity	CRCC207	106	11140	0	8094	11450	0
90000210490	FY22	INPRG	Pleasant St	CLD	3/17/2022		Integrity	CRCC207	45	1775	0	1765	1775	0
90000215797	FY23	INPRG	Oak St CRA	CRA	7/23/2022		Integrity	CRCC207	27	1885	0	1905	1885	0
90000218032	FY23	INPRG	696-786 Atwood Ave CRA	CRA	7/28/2022		Integrity	CRCC207	35	2745	0	1036	2825	0
90000218033	FY23	INPRG	Prospect St CRA	CRA	8/29/2022		Integrity	CRCC207	47	2060	0	2148	2060	0
90000210511	FY23	INPRG	Metropolitan Rd PVD	PVD	6/8/2022		Integrity	CRCC207	79	2655	0	2855	2655	0
90000218031	FY23	INPRG	Burton St BST	BST	9/20/2022		Integrity	CRCC206	44	1960	0	2009	1960	0
90000204631	FY23	INPRG	Sand Pond Rd, WWK	WWK	7/15/2022		Integrity	CRCC203	38	3240	0	3431	3240	0
90000223708	FY23	INPRG	Morse Av, WWK	WWK	4/12/2022		Integrity	CRCC203	43	2595	0	2905	2415	0
90000219165	FY23	INPRG	Center St BST	BST	10/4/2022		Integrity	CRCC203	20	1105	0	1175	1185	0
90000219250	FY23	INPRG	Read Ave, LNC	LNC	8/1/2022		Integrity	CRCC203	18	1495	0	1480	1635	0
90000215452	FY23	INPRG	1-118 Potters Av PVD	PVD	5/3/2022		Integrity	CRCC207	66	3535	0	2992	2935	0
90000214927	FY23	INPRG	Frances Av CRA	CRA	7/8/2022		Integrity	CRCC206	19	1465	0	1530	2545	0
90000218645	FY23	INPRG	Chalapa Av, WSO	WSO	4/26/2022		Integrity	CRCC207	12	760	0	783	760	0
90000219279	FY23	INPRG	Mill St CLD	CLD	8/1/2022		Integrity	CRCC207	14	1230	0	1270	1230	0
90000218047	FY23	INPRG	75-130 Homewood Av NPV	NPV	9/27/2022		Integrity	CRCC207	34	2020	0	2087	2800	0
90000224128	FY23	INPRG	660-1119 Reservoir Av, CRA	CRA	6/10/2022		Integrity	CRCC206	48	5805	0	6077	8530	0
90000220959	FY23	INPRG	Canonchet Av, WWK	WWK	9/28/2022		Integrity	CRCC207	42	2385	0	2323	2355	0
90000214953	FY23	INPRG	Lincoln Av, PAW	PAW	5/16/2022		Integrity	CRCC207	34	210	0	241	1510	0
90000219673	FY23	INPRG	Carrie Av EPV	EPV	6/18/2022		Integrity	CRCC207	13	490	0	580	470	0
90000155334	FY23	INPRG	Railroad Av, WLY	WLY	6/10/2022		Integrity	CRCC203	6	805	0	1066	805	0
90000223446	FY23	INPRG	180-380 Westminster St, PVD	PVD	5/9/2022		Integrity	CRCC207	15	2355	0	1609	3005	0
90000214950	FY23	INPRG	Progress St, PAW	PAW	8/22/2022		Integrity	CRCC207	62	3185	0	0	3185	0
90000219650	FY23	INPRG	Perkins Av CRA	CRA	10/6/2022		Integrity	CRCC207	40	2520	0	2328	2705	0
90000220910	FY23	INPRG	Redfern St NPV	NPV	4/15/2022		Integrity	CRCC207	17	615	0	623	640	0
90000214948	FY23	INPRG	504-546 Smithfield Av, PAW	PAW	4/28/2022		Integrity	CRCC207	89	4740	0	4459	4820	0
90000212440	FY23	INPRG	Cass Av, WSO	WSO	7/22/2022		Integrity	CRCC207	16	1625	0	1915	1700	0
90000211204	FY23	INPRG	Crest Dr, PAW	PAW	7/14/2022		Integrity	CRCC207	79	3550	0	3566	3530	0
90000212476	FY23	INPRG	Wasaga Rd PAW	PAW	10/4/2022		Integrity	CRCC207	17	535	0	597	535	0
90000221929	FY23	INPRG	Providence St WWW	WWW	10/5/2022		CSC	CRCC307	2	233	0	193	189	0
90000219267	FY23	INPRG	Greene St NSF	NSF	4/20/2022		Integrity	CRCC203	16	1405	0	1509	1405	0
90000185670	FY23	INPRG	Woonsocket Hill Rd, NSF	NSF	3/30/2022		Integrity	CRCC207	54	4470	0	4426	4490	0
90000175417	FY23	INPRG	632-710 Lonsdale Av CFL	CFL	6/13/2022		Integrity	CRCC207	81	2970	0	3070	3090	0
90000211272	FY23	INPRG	Eileen Av CRA	CRA	9/7/2022		Integrity	CRCC203	32	2075	0	2142	2135	0
90000219277	FY23	INPRG	E Earle St, CLD	CLD	4/18/2022		Integrity	CRCC207	82	3760	0	4025	3790	0
90000209055	FY23	INPRG	Cowesett @ Quaker, WWW	WWW	5/15/2022		Reliability	C085181	0	90	0	0	75	0
90000212463	FY23	INPRG	Roberta Av PAW	PAW	5/16/2022		Integrity	CRCC207	64	3075	0	3090	3040	0
90000181673	FY23	INPRG	RIS071 / RIS089-Willet @ Forbes EPV	EPV	7/5/2022		Reliability	C077246	0	0	0	952	0	0
90000212431	FY23	INPRG	Summer St, WSO	WSO	6/9/2022		Integrity	CRCC207	179	10445	0	0	10425	0
90000220922	FY23	INPRG	Bellevue Av NPV	NPV	5/17/2022		Integrity	CRCC207	54	2350	0	2565	2385	0
90000214972	FY23	INPRG	Naples Av PVD	PVD	7/9/2022		Integrity	CRCC207	114	4895	0	5142	4825	0
90000220962	FY23	INPRG	156-277 Narragansett Pkwy, WWK	WWK	8/25/2022		Integrity	CRCC207	57	3725	0	3977	3725	0
90000212583	FY23	INPRG	Calderwood Dr, WWK	WWK	5/9/2022		Integrity	CRCC203	56	3225	0	2925	3225	0
90000224499	FY23	INPRG	NBC - Portu Social Club Way	PAW	9/2/2022		CSC	CRCC307	0	268	0	346	254	0

1-16-1 All Project Status

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90000224505	FY23	INPRG	NBC - Division St, PAW	PAW	8/3/2022		CSC	CRCC307	0	422	0	432	350	0
90000227012	FY23	INPRG	Elmwood Av, WWK	WWK	10/3/2022		CSC	CRCC306	13	753	0	890	74	0
90000226192	FY23	INPRG	Fenner Av, EPV	EPV	9/22/2022		CSC	CRCC306	16	452	0	464	488	0
90000226952	FY23	INPRG	Ivy St EPV	EPV	10/6/2022		CSC	CRCC306	19	789	0	806	783	0
90000218468	FY23	INPRG	Reardon Av EPV	EPV	7/28/2022		Integrity	CRCC203	16	1600	0	1567	1540	0
90000204611	FY23	INPRG	1970-2117 Pawtucket Av, EPV	EPV	7/31/2022		Integrity	CRCC203	13	3825	0	2128	3884	0
90000221899	FY23	INPRG	Lake Shore Dr, WWK	WWK	8/29/2022		Integrity	CRCC203	68	5080	0	5290	5080	0
90000229732	FY23	INPRG	Walcott St, PAW	PAW	9/1/2022		CSC	CRCC308	1	280	0	249	280	0
90000227909	FY23	INPRG	Old Mill Ln ECO-RASTER Project PSM	PSM	8/16/2022		Reliability	C082835	0	0	0	0	0	0
90000228151	FY23	INPRG	Merrill St, EPV	EPV	9/26/2022		CSC	CRCC306	26	888	0	915	853	0
90000228146	FY23	INPRG	Holmes Av EPV	EPV	9/24/2022		CSC	CRCC306	3	185	0	190	143	0
90000229358	FY23	INPRG	Grotto Av PAW	PAW	9/26/2022		CSC	CRCC308	15	516	0	535	472	0
90000201453	FY23	INPRG	Thames St (Section 1), NPR	NPR	10/4/2022		Integrity	CRCC205	0	0	0	0	0	0
90000229362	FY23	INPRG	Coe St WSO	WSO	9/17/2022		CSC	CRCC312	2	132	0	124	132	0
90000150319	FY23	INPRG	Marquette Dr, WWK	WWK	9/20/2022		Integrity	CRCC203	45	4115	0	3242	4115	0
90000226934	FY23	INPRG	Cobb St, EPV	EPV	10/21/2022		CSC	CRCC306	13	916	0	920	898	0
90000226505	FY23	INPRG	Wells St, WLY	WLY	11/3/2022		CSC	CRCC306	10	792	0	400	2445	0
90000225865	FY23	INPRG	Geldard St, CLD	CLD	10/19/2022		Integrity	CRCC207	24	905	0	0	915	0
90000212105	FY22	INPRG	Plainfield @ Simmmonsville	JOH	7/6/2022		Reliability	CRCC111	0	0	0	0	0	0
90000220556	FY23	INPRG	Cobble Hill Rd LNC	LNC	4/21/2022		Reliability	CRCC111	12	8100	0	7766	1050	1050
90000220506	FY23	INPRG	Third Av WSO	WSO	9/12/2022		Reliability	CRCC111	69	3960	0	3881	3590	3590
90000216931	FY22	INPRG	Ten Rod Rd NKS	NKS	10/17/2022		Reliability	CRCC111	6	1050	0	656	1050	1050
90000204878	FY21	WSTOP	Lippit Ave WWK	WWK	4/2/2020		CSC	CRCC306	1	190	0	0	190	0
90000207397	FY21	WSTOP	Heights Ave WWK	WWK	5/7/2020		CSC	CRCC306	10	720	418	0	720	0
90000207395	FY21	WSTOP	Friendship St WWK	WWK	5/7/2020		CSC	CRCC306	8	766	766	0	440	0
90000185689	FY21	WSTOP	Dover St, PVD	PVD	11/10/2020		Integrity	CRCC207	58	1501	1501	0	2220	0
90000194351	FY22	WSTOP	Amy St, PVD	PVD	9/14/2021		Integrity	CRCC207	34	845	845	0	1315	0
90000207575	FY21	WSTOP	Commodore St PVD	PVD	1/25/2021		CSC	CRCC306	148	5990	4519	0	7565	0
90000212523	FY22	WSTOP	Elizabeth Dr, NPV	NPV	4/22/2021		Integrity	CRCC207	25	1325	0	0	1160	0
90000221503	FY22	WSTOP	New London Ave	WWW	10/14/2021		CSC	CRCC306	3	230	230	0	220	0
90000180674	FY19	WSTOP	Old Park Ave, CRA	CRA	8/22/2018		Reliability	CRCC111	0	1145	1145		0	0
90000209570	FY21	WSTOP	Franklin St, WLY	WLY	8/18/2021		Reliability	CRCC111	0	450	75	0	0	0
90000219678	FY23	WSTOP	Croade St, WAN	WAN	4/21/2022		Integrity	CRCC203	5	295	0	0	295	0
90000204634	FY22	DISPATCH	Warwick Av WWK	WWK			Integrity	CRCC203	59	5180	0	0	6795	0
90000172062	FY21	DISPATCH	Benjamin Dr NPV	NPV			Integrity	CRCC203	4	120	0	0	1175	0
90000194364	FY22	DISPATCH	Linden Dr PVD	PVD			Integrity	CRCC207	8	325	0	0	325	0
90000194780	FY22	DISPATCH	Rt 10 S Offramp @ Union Av PVD	PVD			Integrity	CRFN224	0	385	0	0	385	0
90000194417	FY22	DISPATCH	Terrace Av, WWK	WWK			Integrity	CRCC203	21	2445	0	0	2350	0
90000204103	FY22	DISPATCH	Cabot St LNC	LNC			CSC	CRCC306	2	70	0	0	58	0
90000212483	FY22	DISPATCH	Oakdale Av PAW	PAW			Integrity	CRCC207	32	1440	0	0	2330	0
90000211833	FY23	DISPATCH	Benefit St, WWK	WWK			Integrity	CRCC203	6	495	0	0	495	0
90000217370	FY22	DISPATCH	George Washington Hwy LNC	LNC			Integrity	CRCC210	1	710	0	0	970	0
90000220815	FY23	DISPATCH	Rawlinson Dr COV	COV			Integrity	CRCC203	7	980	0	0	980	0
90000220826	FY23	DISPATCH	Bald Hill Rd CRA	CRA			Integrity	CRCC203	3	360	0	0	360	0
90000212432	FY23	DISPATCH	Clark St CLD	CLD			Integrity	CRCC207	31	1730	0	0	1820	0
90000220828	FY23	DISPATCH	Gesmondi Dr JOH	JOH			Integrity	CRCC203	16	1190	0	0	1100	0
90000212439	FY23	DISPATCH	224-259 East Av PAW	PAW			Integrity	CRCC207	16	515	0	0	995	0
90000218000	FY23	DISPATCH	Pocasset St JOH	JOH			Integrity	CRCC203	9	725	0	0	725	0
90000219194	FY23	DISPATCH	Stone Av, WWK	WWK			Integrity	CRCC203	21	1540	0	0	1540	0
90000220964	FY23	DISPATCH	S Fairview St JOH	JOH			Integrity	CRCC207	12	750	0	0	750	0
90000218041	FY23	DISPATCH	Osgood Av JOH	JOH			Integrity	CRCC207	14	860	0	0	880	0
90000214976	FY23	DISPATCH	Cottage St, PAW	PAW			Integrity	CRCC203	51	3180	0	0	4965	0
90000219663	FY23	DISPATCH	127-250 Mendon Rd, CLD	CLD			Integrity	CRCC203	6	770	0	0	770	0
90000144219	FY23	DISPATCH	Station @ Pond (RIS-017) CRA	CRA			Reliability	CRIC402	0	0	0	0	0	0
90000217555	FY23	DISPATCH	Mayfield Rd @ Oakland Av, CRA	CRA			Reliability	CRIC402	0	0	0	0	0	0
90000226925	FY23	DISPATCH	Olney St PVD	PVD			Integrity	CRCC207	7	1390	0	0	1475	0
90000228513	FY23	DISPATCH	Sunbury St PVD	PVD			Reliability	CRCC401	4	420	0	0	0	0
90000228757	FY23	DISPATCH	Baker St, PVD	PVD			CSC	CRCC308	13	2115	0	0	2340	0
90000180671	FY23	DISPATCH	Rathbun St, WSO	WSO			Reliability	CRCC111	37	1530	0		335	335
90000208691	FY23	WSCHD	Wolcott @ St. Georges MDT	MDT			Reliability	C084288	0	0	0	0	0	0
90000142764	FY22	WSCHD	1294 Atwood Ave JOH	JOH			Integrity	CRCC203	0	115	0	0	115	0
90000210583	FY23	WSCHD	N Broadway, EPV	EPV			Integrity	CRCC203	3	605	0	0	605	0
90000214938	FY23	WSCHD	Emanuel St NPV	NPV			Integrity	CRCC207	61	3860	0	0	4450	0
90000211601	FY23	WSCHD	Whipple St, CLD	CLD			Integrity	CRCC203	5	220	0	0	235	0
90000212594	FY23	WSCHD	Arnolds Neck Dr, WWK	WWK			Integrity	CRCC203	2	300	0	0	300	0
90000217235	FY23	WSCHD	Glenwood Dr, WWK	WWK			Integrity	CRCC203	3	75	0	0	150	0
90000220931	FY23	WSCHD	Bradford St BST	BST			Integrity	CRCC207	34	2020	0	0	2735	0
90000218038	FY23	WSCHD	419-583 N Broadway EPV	EPV			Integrity	CRCC207	73	3750	0	0	3745	0
90000230430	FY23	WSCHD	600 Social St, WSO	WSO			CSC	CRCC312	0	14	0	0	14	0
90000224933	FY23	WSCHD	220-285 Wampanoag Trl, EPV	EPV			Reliability	CRCC111	0	330	0		0	0

1-16-1 All Project Status

Main WO#	Plan Year	Project Status	Project Title	Town	Actual Start Date	Date Completed	Program	Funding Code	#Svcs- Project Scope	Project Scope Est. Install Footage	Footage Installed in FY22 or Prior	Actual Installed Footage FY23	Estimated Abandonment Footage	Actual Abandonment Footage *(once complete)*
90000225628	FY23	WSCHD	300-400 Wampanoag Trl, EPV	EPV			Reliability	CRCC111	0	900	0		0	0
90000195699	FY23	AWPER	1-111 Harris Av, PVD	PVD			Integrity	CRCC207	0	0	0	0	1630	0
90000204547	FY22	AWPER	Lambert Av (Insertion) WSO	WSO			Integrity	CRCC207	1	375	0	0	375	0
90000194262	FY22	AWPER	573-744 Hope St BST	BST			Integrity	CRCC207	48	2270	0	0	2270	0
90000194369	FY22	AWPER	Ocean St PVD	PVD			Integrity	CRCC207	50	1845	0	0	1945	0
90000175665	FY22	AWPER	Carr St PVD	PVD			Integrity	CRCC207	48	1430	0	0	1430	0
90000142618	FY22	AWPER	Charles St PVD	PVD			Integrity	CRCC207	46	2210	0	0	2210	0
90000208982	FY21	AWPER	Thames @ Washington Sq 12in Valve	NPR			Integrity	C085142	0	0	0	0	0	0
90000208968	FY21	AWPER	Thames @ W Narragansett 12in Valve NPR	NPR			Integrity	C085142	0	0	0	0	0	0
90000209009	FY21	AWPER	Rhode Island @ Champlin 6in Valve	NPR			Integrity	C085142	0	0	0	0	0	0
90000155218	FY22	AWPER	Brighton St PVD	PVD			Integrity	CRCC207	21	80	0	0	710	0
90000185659	FY22	AWPER	Broadway NPR	NPR			Integrity	CRCC207	18	1620	0	0	1780	0
90000185666	FY22	AWPER	Smith St NPV	NPV			Integrity	CRCC207	25	2450	0	0	2450	0
90000118037	FY22	AWPER	Williams St NPR	NPR			Integrity	CRCC207	39	2180	0	0	2225	0
90000204638	FY22	AWPER	Ward Ave WLY	WLY			Integrity	CRCC203	50	4140	0	0	6415	0
90000210746	FY22	AWPER	Abbott St PVD	PVD			Integrity	CRCC207	58	2455	0	0	2375	0
90000210644	FY22	AWPER	Burnside St PVD	PVD			Integrity	CRCC207	38	1390	0	0	1390	0
90000212419	FY22	AWPER	531-590 Manton Av PVD	PVD			Integrity	CRCC207	45	1250	0	0	3205	0
90000212518	FY22	AWPER	307-349 Hope St PVD	PVD			Integrity	CRCC207	11	225	0	0	1625	0
90000187222	FY22	AWPER	Reservoir Av PVD	PVD			Integrity	CRCC207	13	2835	0	0	3445	0
90000142541	FY22	AWPER	Whitehall St PVD	PVD			Integrity	CRCC207	41	1950	0	0	1950	0
90000175676	FY22	AWPER	Gloucester St PVD	PVD			Integrity	CRCC203	30	1160	0	0	1260	0
90000210913	FY22	AWPER	Waterman Av EPV	EPV			Integrity	CRCC206	44	4010	0	0	4010	0
90000210631	FY22	AWPER	Woodbine St PVD	PVD			Integrity	CRCC207	23	605	0	0	605	0
90000194359	FY22	AWPER	Gallup St PVD	PVD			Integrity	CRCC207	50	2520	0	0	3810	0
90000212520	FY21	AWPER	632-734 Hope St PVD	PVD			Integrity	CRCC206	49	2225	0	0	2325	0
90000212129	FY21	AWPER	Penn St PVD	PVD			Integrity	CRCC207	40	2135	0	0	2070	0
90000155376	FY22	AWPER	Delaine St, PVD	PVD			Integrity	CRCC207	16	1430	0	0	2295	0
90000218389	FY22	AWPER	2145-2289 Pawtucket Av EPV	EPV			Integrity	CRCC206	9	1220	0	0	1220	0
90000218701	FY22	AWPER	Lonsdale Ave Bridge	PAW			Integrity	CRCC225	0	210	0	0	210	0
90000221185	FY23	AWPER	125-201 Washington St PVD	PVD			Integrity	CRCC207	3	655	0	0	680	0
90000222544	FY23	AWPER	1 Sanford St PVD	PVD			Integrity	CRCC210	1	250	0	0	0	0
90000220425	FY23	AWPER	Dexter St PVD	PVD			Integrity	CRCC207	0	0	0	0	0	0
90000220401	FY23	AWPER	Waldo Dr PVD	PVD			Integrity	CRCC207	0	0	0	0	0	0
90000222517	FY23	AWPER	Waterman Greystone Outlet Valve Replacement NPV	NPV			Reliability	CRIC213	0	0	0	0	0	0
90000215166	FY23	AWPER	Pierce St EGW	EGW			Integrity	CRCC203	4	170	0	0	170	0
90000211750	FY23	AWPER	Staniford St PVD	PVD			Integrity	CRCC207	3	300	0	0	385	0
90000211643	FY23	AWPER	Langdon St PVD	PVD			Integrity	CRCC207	62	2665	0	0	2635	0
90000220842	FY23	AWPER	Washington St NKS	NKS			Integrity	CRCC203	5	375	0	0	375	0
90000211746	FY23	AWPER	55-120 Ellery St PVD	PVD			Integrity	CRCC207	61	2915	0	0	2915	0
90000215933	FY23	AWPER	1-173 Woonasquatucket Av, NPV	NPV			Integrity	CRCC207	44	3070	0	0	3070	0
90000220844	FY23	AWPER	Church Ln NKS	NKS			Integrity	CRCC203	5	390	0	0	390	0
90000220896	FY23	AWPER	Upland Av EGW	EGW			Integrity	CRCC203	5	390	0	0	390	0
90000220893	FY23	AWPER	Water St EGW	EGW			Integrity	CRCC203	4	705	0	0	705	0
90000217932	FY23	AWPER	46-52 Top St, PVD	PVD			Integrity	CRCC207	4	145	0	0	145	0
90000220897	FY23	AWPER	Third Av EGW	EGW			Integrity	CRCC203	2	225	0	0	225	0
90000220899	FY23	AWPER	Fourth Av EGW	EGW			Integrity	CRCC203	2	100	0	0	100	0
90000210512	FY23	AWPER	Ruggles St PVD	PVD			Integrity	CRCC207	49	1490	0	0	2030	0
90000218064	FY23	AWPER	Early St - CISBOT, PVD	PVD			Integrity	CRCC205	0	1185	0	0	0	0
90000155243	FY23	AWPER	1016-1100 Hope St, PVD	PVD			Integrity	CRCC207	10	960	0	0	1190	0
90000217203	FY23	AWPER	Yale Av, PVD	PVD			Integrity	CRCC207	5	140	0	0	140	0
90000218059	FY23	AWPER	1-94 Legion Wy - CISBOT, CRA	CRA			Integrity	CRCC205	0	1625	0	0	1690	0
90000142680	FY23	AWPER	300-445 Elmwood Av PVD	PVD			Integrity	CRCC207	23	3920	0	0	4490	0
90000214966	FY23	AWPER	Duncan Av, PVD	PVD			Integrity	CRCC207	45	1580	0	0	1455	0
90000215374	FY23	AWPER	Baltimore St, PVD	PVD			Integrity	CRCC203	13	710	0	0	710	0
90000215307	FY23	AWPER	Somerset St PVD	PVD			Integrity	CRCC207	36	2650	0	0	2705	0
90000214973	FY23	AWPER	Ohio Av PVD	PVD			Integrity	CRCC207	63	2175	0	0	2175	0
90000218051	FY23	AWPER	Hanover St, PVD	PVD			Integrity	CRCC207	63	2055	0	0	2055	0
90000214970	FY23	AWPER	Dudley St PVD	PVD			Integrity	CRCC206	18	1730	0	0	2255	0
90000220949	FY23	AWPER	Broadmoor Rd CRA	CRA			Integrity	CRCC207	43	3590	0	0	3480	0
90000212456	FY23	AWPER	Seneca Av PAW	PAW			Integrity	CRCC207	32	2025	0	0	2010	0
90000220806	FY23	AWPER	Bald Hill Rd-East Av, WWK	WWK			Reliability	CRCC401	10	3580	0	0	3444	0
90000215259	FY23	AWPER	Anthony Av, PVD	PVD			Integrity	CRCC207	63	4235	0	0	4335	0
90000177418	FY23	AWPER	602-710 Killingly St - CISBOT, JOH	JOH			Integrity	CRCC205	0	0	0	0	2300	0
90000220901	FY23	AWPER	Link St, WWK	WWK			Integrity	CRCC203	69	2935	0	0	2935	0
90000194354	FY23	AWPER	Bath St PVD	PVD			Integrity	CRCC207	31	3115	0	0	3915	0
90000215465	FY23	AWPER	336-463 Benefit St, PVD	PVD			Integrity	CRCC206	30	2125	0	0	2530	0
90000211621	FY23	AWPER	Ivy St PVD	PVD			Integrity	CRCC207	57	2370	0	0	2680	0

1-16-1 All Project Status

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90000215537	FY23	AWPER	Glenham St PVD	PVD			Integrity	CRCC207	55	955	0	0	2240	0
90000218048	FY23	AWPER	Spruce St, PVD	PVD			Integrity	CRCC207	16	845	0	0	845	0
90000199043	FY23	AWPER	Hope Furnace Rd, SCT	SCT			CSC	CRCC306	0	60	0	0	49	0
90000217184	FY23	AWPER	481-604 Blackstone St, WSO	WSO			Integrity	CRCC207	16	1240	0	0	1795	0
90000204675	FY23	AWPER	957-1074 Mineral Spring Av NPV	NPV			Integrity	CRCC207	29	3580	0	0	4105	0
90000225808	FY23	AWPER	1570-1802 Mendon Rd, CLD	CLD			Integrity	CRCC203	0	2805	0	0	2805	0
90000228624	FY23	AWPER	Orient St WWK	WWK			Integrity	CRCC203	22	1975	0	0	1975	0
90000231158	FY23	AWPER	1728-1847 Cranston St CRA	CRA			CSC	CRCC306	48	3600	0	0	3600	0
90000216897	FY22	AWPER	Harris Av PVD	PVD			Reliability	CRCC111	6	970	0		0	0
90000224894	FY23	AWPER	Elmwood Av, WWK	WWK			Reliability	CRCC111	4	1000	0		0	0
90000194347	FY22	NRTD	330-505 Silver Spring St PVD	PVD			Integrity	CRCC207	7	2345	0	0	2395	0
90000173914	FY21	NRTD	Division St Bridge Brackets PAW	PAW			Integrity	CRRC301	0	0	0	0	0	0
90000204960	FY21	NRTD	Van Zandt Ave WWK Relay	WWK			CSC	CRCC306	31	2545	2545	0	2395	0
90000175911	FY22	NRTD	S Main St, WSO	WSO			Integrity	CRCC207	28	1710	0	0	3450	0
90000207302	FY21	NRTD	Webb Ave WWK	WWK			CSC	CRCC306	44	2745	725	0	2745	0
90000204961	FY21	NRTD	125 Wentworth Ave WWK	WWK			CSC	CRCC306	1	215	0	0	215	0
90000204838	FY22	NRTD	Wentworth Ave WWK	WWK			CSC	CRCC306	25	2530	0	0	2435	0
90000206081	FY22	NRTD	Test Camera pits CI Lining Russell St PVD	PVD			Integrity	CRCC204	0	0	0	0	0	0
90000184051	FY22	NRTD	Island Av EPV (RR Crossing), EPV	EPV			Integrity	CRCC203	3	640	0	0	640	0
90000207468	FY21	NRTD	Carroll Ave @ Ocean NPR	NPR			Reliability	CRIC402	0	0	0	0	0	0
90000188537	FY22	NRTD	Harris Av PVD	PVD			Integrity	CRCC207	16	3108	0	0	3685	0
90000211769	FY22	NRTD	Conant St PAW	PAW			Integrity	CRCC203	8	2085	0	0	2085	0
90000210499	FY22	NRTD	Atwells Av PVD	PVD			Integrity	C081157	42	1430	0	0	2740	0
90000210496	FY22	NRTD	Wellington Av CRA	CRA			Integrity	CRCC206	2	850	0	0	850	0
90000220422	FY23	NRTD	Bourne Ave EPV	EPV			Integrity	CRCC206	0	0	0	0	0	0
90000220412	FY23	NRTD	North Broadway EPV	EPV			Integrity	CRCC203	0	0	0	0	0	0
90000220424	FY23	NRTD	New London Ave CRA	CRA			Integrity	CRCC203	0	0	0	0	0	0
90000220912	FY23	NRTD	Miles Av NPV	NPV			Integrity	CRCC207	17	825	0	0	825	0
90000224338	FY23	NRTD	Atwells Av Bridge PVD	PVD			Reliability	CRCC225	0	0	0	0	290	0
90000219236	FY23	NRTD	873-1010 Cranston St CRA	CRA			Integrity	CRCC207	33	2415	0	0	2470	0
90000217831	FY23	NRTD	364-420 Wellington Av, CRA	CRA			Integrity	CRCC207	28	635	0	0	2305	0
90000219059	FY23	NRTD	Old River Rd, LNC	LNC			Integrity	CRCC207	59	4315	0	0	4810	0
90000212041	FY23	NRTD	Old Main St, LNC	LNC			Integrity	CRCC207	75	6665	0	0	7500	0
90000221104	FY23	NRTD	120-262 Tuckerman Av, MDT	MDT			Integrity	CRCC455	112	8300	0	0	300	0
90000204089	FY21	NRTD	Park @ Maple CRA	CRA			Reliability	CRIC402	0	0	0	0	0	0
90000218021	FY23	NRTD	Oxford St, PVD	PVD			Integrity	CRCC204	96	6475	0	0	8715	0
90000180116	FY22	NRTD	Central Av PAW	PAW			Reliability	CRCC111	0	2000	0		0	0
90000225974	FY23	PENDING	Herschel St PVD	PVD			Integrity	CRCC207	0	0	0	0	0	0
90000212517	FY23	PENDING	Washington St, PVD	PVD			Integrity	CRCC206	0	4360	0	0	5415	0
90000215445	FY23	PENDING	578-776 Plainfield St, PVD	PVD			Integrity	CRCC207	0	2465	0	0	4090	0
90000220920	FY23	PENDING	Oxbow Farms Apartment Complex, MDT	MDT			Integrity	CRCC210	0	10000	0	0	0	0
90000204830	FY23	PENDING	Atlantic Blvd NPV	NPV			Integrity	CRCC207	0	7040	0	0	6420	0
90000215125	FY23	PENDING	Parkside Dr, WWK	WWK			Integrity	CRCC207	0	6205	0	0	5690	0
90000207070	FY23	PENDING	Tidewater Dr, WWK	WWK			Integrity	CRCC203	0	2045	0	0	2830	0
90000215424	FY23	PENDING	Moccasin Dr, WWK	WWK			Integrity	CRCC203	0	4300	0	0	4150	0
90000220936	FY23	PENDING	Constitution St BST	BST			Integrity	CRCC207	0	2850	0	0	2810	0
90000220963	FY23	PENDING	Harding Av JOH	JOH			Integrity	CRCC207	0	3755	0	0	3665	0
90000217168	FY23	PENDING	68-151 Bay View Av, BST	BST			Integrity	CRCC203	0	3165	0	0	3070	0
90000212383	FY23	PENDING	Parade St PVD	PVD			Integrity	CRCC207	0	2115	0	0	3280	0
90000218007	FY23	PENDING	Benbridge Av, WWK	WWK			Integrity	CRCC203	0	4440	0	0	4335	0
90000142705	FY23	PENDING	1-170 Spring St, NPR	NPR			Integrity	CRCC207	0	2605	0	0	2515	0
90000219256	FY23	PENDING	391-480 Woodward Rd NPV	NPV			Integrity	CRCC203	0	2930	0	0	2955	0
90000219278	FY23	PENDING	480-547 Woodward Rd NPV	NPV			Integrity	CRCC203	0	2240	0	0	2175	0
90000219208	FY23	PENDING	Ashby St JOH	JOH			Integrity	CRCC207	0	3600	0	0	3050	0
90000204673	FY23	PENDING	Tilley Av NPR	NPR			Integrity	CRCC207	0	1560	0	0	1470	0
90000211786	FY23	PENDING	1423-1741 Atwood Av, JOH	JOH			Integrity	CRCC203	0	4535	0	0	4580	0
90000220925	FY23	PENDING	Tennyson Rd, WWK	WWK			Integrity	CRCC207	0	1975	0	0	1235	0
90000214975	FY23	PENDING	Main St, NSF	NSF			Integrity	CRCC203	0	1605	0	0	1595	0
90000118390	FY23	PENDING	Maple Av MDT	MDT			Integrity	CON0034	0	2785	0	0	2440	0
90000220956	FY23	PENDING	Catherine St NPR	NPR			Integrity	CRCC207	0	1815	0	0	1770	0
90000211760	FY23	PENDING	Governors Dr, WWK	WWK			Integrity	CRCC203	0	2095	0	0	2205	0
90000146500	FY23	PENDING	Redwood Dr, NPV	NPV			Integrity	CRCC203	0	1205	0	0	1205	0
90000214977	FY23	PENDING	Alden Av, WWK	WWK			Integrity	CRCC203	0	600	0	0	510	0
90000155192	FY23	PENDING	Webster St NPR	NPR			Integrity	CRCC207	0	2050	0	0	2030	0
90000219163	FY23	PENDING	Rolling Green Rd NPR	NPR			Integrity	CRCC203	0	2970	0	0	2970	0
90000194335	FY23	PENDING	George St, PAW	PAW			Integrity	CRCC207	0	2260	0	0	3255	0
90000220804	FY23	PENDING	Bay Spring Av, BRG	BRG			Integrity	CRCC203	0	1105	0	0	1000	0
90000216936	FY23	PENDING	Dearborn St, NPR	NPR			Integrity	CRCC207	0	590	0	0	590	0

1-16-1 All Project Status

Main WO#	Plan Year	Project Status	Project Title	Town	Actual Start Date	Date Completed	Program	Funding Code	#Svcs- Project Scope	Project Scope Est. Install Footage	Footage Installed in FY22 or Prior	Actual Installed Footage FY23	Estimated Abandonment Footage	Actual Abandonment Footage *(once complete)*
90000220850	FY23	PENDING	Morris St, WWK	WWK			Integrity	CRCC203	0	720	0	0	640	0
90000220953	FY23	PENDING	25-90 N Broadway EPV	EPV			Integrity	CRCC206	0	1055	0	0	1055	0
90000220866	FY23	PENDING	E Capalbo Dr, WLY	WLY			Integrity	CRCC203	0	935	0	0	935	0
90000220863	FY23	PENDING	70-250 Centerville Rd, WWK	WWK			Integrity	CRCC203	0	2850	0	0	2955	0
90000220905	FY23	PENDING	North St JOH	JOH			Integrity	CRCC207	0	340	0	0	340	0
90000215638	FY23	PENDING	Fairview St PVD	PVD			Integrity	CRCC207	0	630	0	0	640	0
90000131590	FY23	PENDING	Cowesett @ Quaker, WWW	WWW			Reliability	CRIC402	0	0	0	0	0	0
90000207469	FY23	PENDING	3362 Kingstown Rd (Waltes Corner), NKS	NKS			Reliability	CRIC402	0	0	0	0	0	0
90000217562	FY23	PENDING	Dyer @ Pine St, PVD	PVD			Reliability	CRIC402	0	0	0	0	0	0
90000228205	FY23	PENDING	Division St, WSO	WSO			CSC	CRCC306	0	0	0	0	0	0
90000227744	FY23	PENDING	Oregon Av WSO	WSO			CSC	CRCC306	0	0	0	0	0	0
90000229281	FY23	PENDING	969-1030 Park Av CRA	CRA			Integrity	CRCC206	39	5025	0	0	5340	0
90000227717	FY23	PENDING	Pine St CFL	CFL			CSC	CRCC306	0	0	0	0	0	0
90000227715	FY23	PENDING	Pine St PAW	PAW			CSC	CRCC306	0	0	0	0	0	0
90000226966	FY23	PENDING	RIDOT Davisville RR Bridge NKS	NKS			CSC	CRCC307	0	0	0	0	0	0
90000227441	FY23	PENDING	Rand St CFL	CFL			CSC	CRCC306	0	0	0	0	0	0
90000220913	FY23	PENDING	Cannon St	CRA			Reliability	CRCC401	0	0	0	0	0	0
90000227092	FY23	PENDING	E Knowlton St, EPV	EPV			CSC	CRCC306	0	0	0	0	0	0
90000224932	FY23	PENDING	Roger Williams Av, EPV	EPV			Reliability	CRCC401	0	0	0	0	0	0
90000220955	FY23	PENDING	Elm Av EPV	EPV			Integrity	CRCC207	0	0	0	0	0	0
90000227753	FY23	PENDING	Railroad Av, LNC	LNC			Integrity	CRCC207	0	0	0	0	0	0
90000224888	FY23	PENDING	Hayward St, PAW	PAW			Reliability	CRCC111	0	0	0	0	0	0
90000227088	FY23	PENDING	Baldwin St, PAW	PAW			CSC	CRCC306	0	0	0	0	0	0
90000227019	FY23	PENDING	Appleton Ave, PAW	PAW			CSC	CRCC306	0	0	0	0	0	0
90000227087	FY23	PENDING	Varnum Ave, PAW	PAW			CSC	CRCC306	0	0	0	0	0	0
90000184270	FY23	PENDING	Petteys Av - LINING, PVD	PVD			Integrity	C078189	0	0	0	0	0	0
90000225658	FY23	PENDING	Barstow St PVD	PVD			Integrity	CRCC207	34	2075	0	0	2105	0
90000217989	FY23	PENDING	Macarthur Dr SMF	SMF			Integrity	CRCC203	0	0	0	0	0	0
90000224714	FY23	PENDING	Third Av, WWK	WWK			CSC	CRCC307	0	0	0	0	0	0
90000219108	FY23	PENDING	332-458 River St, WSO	WSO			Integrity	CRCC206	0	0	0	0	0	0
90000230255	FY23	PENDING	Bentley St, EPV	EPV			Integrity	CRCC210	0	0	0	0	0	0
90000209541	FY23	PENDING	Old River Rd, LNC	LNC			Reliability	CRCC401	0	0	0	0	0	0
90000228264	FY23	PENDING	Orient St WWK	WWK			Integrity	CRCC203	0	0	0	0	0	0
90000230192	FY23	PENDING	240-443 Purgatory Rd MDT	MDT			CSC	CRCC306	28	3225	0	0	3205	0
90000187225	FY23	PENDING	Burlington St PVD	PVD			Integrity	CRCC207	0	0	0	0	0	0
90000226362	FY23	PENDING	RIDOT Prov St Brdg WWW	WWW			CSC	CRCC307	0	0	0	0	0	0
90000226218	FY23	PENDING	RIDOT Mendon Rd Bridge 99psig CLD	CLD			CSC	CRCC307	0	0	0	0	0	0
90000226220	FY23	PENDING	RIDOT Mendon Rd Bridge 60psig CLD	CLD			CSC	CRCC307	0	0	0	0	0	0
90000230194	FY23	PENDING	88-153 Southern St CRA	CRA			CSC	CRCC306	0	0	0	0	0	0
90000229980	FY23	PENDING	Wolcott Ave, MDT	MDT			CSC	CRCC455	0	0	0	0	0	0
90000230850	FY23	PENDING	Sinclair Av - PVD	PVD			CSC	CRCC306	0	0	0	0	0	0
90000230322	FY23	PENDING	250-1121 Centerville Rd, WWK	WWK			CSC	CRCC306	0	0	0	0	0	0
90000231132	FY23	PENDING	Sylvan Dr Bridge EGW	EGW			CSC	CRCC225	0	515	0	0	180	0
90000231179	FY23	PENDING	Suffolk Av PAW	PAW			CSC	CRCC306	0	0	0	0	0	0
90000231160	FY23	PENDING	Abbott St PAW	PAW			CSC	CRCC306	0	0	0	0	0	0
90000231622	FY23	PENDING	Summit St EPV	EPV			CSC	CRCC306	0	0	0	0	0	0
90000218829	FY23	PENDING	RIDOT Reservoir Ave Bridge No. 327 PVD	PVD			CSC	CRCC306	0	0	0	0	5050	0
90000226507	FY23	PENDING	Henry St, WLY	WLY			CSC	CRCC306	0	0	0	0	836	0
90000231918	FY24	PENDING	Highland Ave Area NPV	NPV			CSC	CRCC306	0	0	0	0	1786	0
90000217564	FY23	RECEIVED	Stony Ln @ Rt 2, NKS	NKS			Reliability	CRIC402	0	0	0	0	0	0
90000228516	FY24	RECEIVED	Mason @ Asylum WSO	WSO			Reliability	CRIC213	0	0	0	0	0	0
90000212910	FY22	CANCELED	Elder Pl PVD	PVD			Integrity	CRCC210	2	170	0		170	0
90000210836	FY22	CANCELED	Quaker Lane WWW	WWW			Integrity	CRCC203	0	350	0		535	0
90000217566	FY23	CANCELED	W Main @ Oliphant, MDT	MDT			Reliability	CRIC402	0	0	0		0	0
90000204095	FY23	CANCELED	Regulator Replacement Post @ Byron RIS-036, WWK	WWK			Reliability	CRIC402	0	0	0		0	0
90000226490	FY23	CANCELED	Henry St, WLY	WLY			CSC	CRCC307	0	0	0		0	0
90000231173	FY23	CANCELED	Amherst St @ Valley St PVD	PVD			CSC	CRCC312	20	20	0		20	0
90000207957	FY21	CANCELED	Memorial Blvd NPR	NPR			Reliability	CRCC111	0	2080	0		7030	0

	Project Name	City/Town	Work Order Number	Contractor	Project Comments
1st Wave	**Pettis @ N. Main RIS-083**	Providence	90000145110	Ferreira	FCOMP
	Cowesett Rd RIS-133-40 CDI Project Complex Project	West Warwick	90000131590	Bond	Station Installed, Control tubing still being installed by I&R.
	816 Middle Road OE Shut down window April 1st- Nov 15th	East Greenwich	90000204096	AGI	FCOMP
2nd Wave	**Plainfield @ Simmonsville** OE Shutdown Window July 1st -August 15th	Johnston	90000212105	Ferreira	Station Installed, Control tubing still being installed by I&R.
	Willet @ Forbes (RIS-071)	East Providence	90000181673	AGI	25psi station turned on. 5psi station still waiting to be tubed.
	Willet @ Forbes (RIS-089)				
3rd Wave	**Station @ Pond (RIS-017)**	Cranston	90000144219	Ferreira	Deferred to FY24 due to Oct 15 shutdown window.
	Park @ Maple (RIS-018)	Cranston	90000204089	Ferreira	WSCHD – Potentially will start during winter, but not completed until the Spring.
Future/Backup Work	**Smith @ Sunset**	North Providence	90000204283	TBD	Design Complete. Valve replacement INPRG.
	Wolcott @ St. Georges	Middletown	90000208691	TBD	Design Complete

Priority	Address	WO#	Project Status	Contractor	Pits	Joints
1	Tobey St (2 of 2), PVD	90000201184	FCOMP	AGI	3	79
2	Thames St (Section 1), NPR	90000201453	INPRG	AGI	2	128
3	1092-1247 Chalkstone Av, PVD	90000224287	FCOMP	AGI	2	115
4	Early St, PVD	90000218064	AWPER	AGI	2	98
5	94-188 Legion Way, CRA	90000224271	FCOMP	AGI	2	91

Address	City/Town	WO#	Project Status
E Main @ Turner Road	Middletown	90000207467	FCOMP
747 Bullocks Point Av	East Providence	90000207442	FCOMP
Warwick Ave @ W shore	Warwick	90000217567	FCOMP
6 Long Ln	North Kingstown	90000217548	FCOMP
Waterman @ Whitman	Smithfield	90000207499	FY24
Mayfield Rd @ Oaklawn	Cranston	90000217555	FY24
Stony Ln @ Rt 2	North Kingstown	90000217564	FY24
3362 Kingstown Rd (Waltes Corner)	South Kingstown	90000207469	FY24
Dyer @ Pine St	Providence	90000217562	FY24
Carroll @ Ocean Dr	Newport	90000207468	REDESIGN
W Main @ Oliphant	Middletown	90000217566	CANCEL
Boulevard St @ Miantonomi	Middletown	90000207471	CANCEL

Address	WO#	Project Status	Contractor
St. James, Woonsocket	90000208671	FCOMP	GPL

Division 1-17

Request:

Provide a list of all projects listed in Div 1-16 that began prior to the start of FY 2023 (April 1, 2022) and have not been abandoned to date. Please include an estimated date of abandonment.

Response:

Please see Attachment DIV 1-17 Projects List.

Plan Year	Project Status	Project Title	Town	Actual Start Date	Estimated Date of Abandonment	Program	#Svcs-Project Scope	Project Scope Est. Install Footage	Footage Installed in FY22 or Prior	Actual Installed Footage FY23	Estimated Abandonment Footage
FY21	INPRG	Althea St, PVD	Providence	12/11/2020	Apr-Jun CY23	Integrity	6	682	682	-	705
FY21	WSTOP	Dover St, PVD	Providence	11/10/2020	Apr-Jun CY23	Integrity	58	1,501	1,501	-	2,220
FY22	WSTOP	Amy St, PVD	Providence	9/14/2021	Apr-Jun CY23	Integrity	34	845	845	-	1,315
FY22	INPRG	Branch Av, PVD	Providence	10/21/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	33	3,210	2,622	-	3,180
FY21	INPRG	Dean St, PVD	Providence	8/6/2020	Q4 FY23 (Jan-Mar 2023)	Integrity	54	3,752	3,752	-	4,260
FY22	INPRG	Blackstone St, WSO	Woonsocket	7/16/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	24	2,294	2,294	-	2,265
FY22	INPRG	Ernest St, PVD	Providence	8/27/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	4	687	687	-	3,630
FY22	INPRG	Butler St, CFL	Central Falls	11/29/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	78	3,585	-	3,599	3,435
FY22	INPRG	Haven Ave CRA	Cranston	5/15/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	83	6,006	6,006	-	6,740
FY22	INPRG	Waterman Ave NPV	North Providence	7/1/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	67	1,833	1,833	-	3,170
FY22	INPRG	Summit Ave	North Smithfield	11/3/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	16	610	310	-	630
FY22	INPRG	Slade St PAW	Pawtucket	9/24/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	30	1,473	1,473	-	1,495
FY22	INPRG	Willow Ave	Woonsocket	6/9/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	91	4,332	4,332	-	5,090
FY21	INPRG	Waterman Ave NPV	Smithfield	7/23/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	54	1,865	1,865	-	6,080
FY21	INPRG	Smithfield Rd	North Smithfield	10/28/2021	Q4 FY23 (Jan-Mar 2023)	Integrity	61	4,445	4,235	690	6,815
FY22	INPRG	Pleasant St	Cumberland	3/17/2022	Q4 FY23 (Jan-Mar 2023)	Integrity	45	1,775	-	1,765	1,775
FY23	INPRG	Woonsocket Hill Rd, NSF	North Smithfield	3/30/2022	Q4 FY23 (Jan-Mar 2023)	Integrity	54	4,470	-	4,426	4,490
FY21	WSTOP	Commodore St PVD	Providence	1/25/2021	Q4 FY23 (Jan-Mar 2023)	CSC	148	5,990	4,519	-	7,565
FY21	WSTOP	Lippit Ave WWK	Warwick	4/2/2020	Unknown- On Indian burial ground. Town revoked permit. Pending update from town.	CSC	1	190	-	-	190
FY21	WSTOP	Heights Ave WWK	Warwick	5/7/2020	Unknown- On Indian burial ground. Town revoked permit. Pending update from town.	CSC	10	720	418	-	720
FY21	WSTOP	Friendship St WWK	Warwick	5/7/2020	Unknown- On Indian burial ground. Town revoked permit. Pending update from town.	CSC	8	766	766	-	440
FY22	WSTOP	New London Ave	West Warwick	10/14/2021	Unknown. Pending easement.	CSC	3	230	230	-	220
FY22	INPRG	RIDOT Reservoir Ave Bridge	Providence	6/7/2021	Unknown. Pending RIDOT bridge contractor readiness.	CSC	2	729	-	-	828
FY22	WSTOP	Elizabeth Dr, NPV	North Providence	4/22/2021	Unknown. Pending state permit to cross Mineral Spring.	Integrity	25	1,325	-	-	1,160

Division 1-18

Request:

Provide a list of all proposed proactive main replacement, Public Works, Reliability, Reinforcement, Rehabilitation, and Regulator Station projects for CY 2023 and CY 2024. Please include installation miles, abandonment miles and number of services.

Response:

Please see Attachment DIV 1-18 for the 9-month CY 2023 and 12-month CY 2024 Projects List. Please note, this is a list of main installation and replacement projects that are in addition to the projects included in the Company's response to Division 1-16 (which contains projects that have not yet started and may roll into 9-month CY 2023/ 12-month CY 2024).

For a list of planned Rehabilitation projects, please see the Company's responses to DIV 1-21 and DIV 1-22.

For a list of planned Regulator Station projects, please see the Company's response to DIV 1-34.

9-month CY 2023 and CY 2024 Project List
*Note, this is a list of main installation and replacement projects that are in addition to projects on DIV 1-16 (which contains projects that have not yet started and may roll into 9-month CY 2023/ CY 2024)

WO	Project Title	Town	Program	Install Length	Est Abandonment	Est. Services
90000218149	NPR (10-to-35) P1	Newport	Reliability	2802	1660	7
90000220578	NPR (10-to-35) P2	Newport	Reliability	TBD	TBD	TBD
90000220578	NPR (10-to-35) P3	Newport	Reliability	TBD	TBD	TBD
90000224933 90000225628	EPV 250-285 & 300-400 Wampanoag Trail (99)	East Providence	Reinforcement	2000	0	0
90000220636	PAW Central Ave (18)	Pawtucket	Reinforcement	1530	0	0
90000231868	PAW Greene St & Central Av (99)	Pawtucket	Reinforcement	1805	0	0
90000231880	NGT Ocean Rd (35)	Narragansett	Reinforcement	1600	0	0
90000231881	NGT Knowles Wy (35)	Narragansett	Reinforcement	350	0	0
90000225018	SKS Kersey Rd (35) P1	South Kingstown	Reinforcement	2730	400	3
90000231875	EPV Greenwich Av (LP-99)	East Providence	Reinforcement	7550	7550	TBD
90000231864	PAW Central Av @ Middle St (99)	Pawtucket	Reinforcement	450	0	0
90000231922	LNC Railroad St, Manville (60) P1	Lincoln	Reinforcement	1350	1350	6
90000226102	LNC River Rd (LP-99)	Lincoln	Reinforcement	1350	1095	8
90000231856	LNC Beverly Dr (LP-99)	Lincoln	Reliability	4600	4600	TBD
90000231076	NPV 1-26 Borah St (LP-to-60)	North Providence	Reliability	600	600	8
90000231075	WSO Diamond Hill Rd-Dewey St (60)	Woonsocket	Reliability	730	0	4
90000225770	Anthony Dr, CLD	Cumberland	Integrity	1210	1230	11
90000225838	Mullen Av, CLD	Cumberland	Integrity	5795	5200	50
90000225842	Boyle Av, CLD	Cumberland	Integrity	325	255	4
90000226153	Glenside Rd, CLD	Cumberland	Integrity	1410	1335	14
90000226154	Fountain St, CLD	Cumberland	Integrity	1395	1395	11
90000226150	Hazel St, LNC	Lincoln	Integrity	2390	2420	42
90000225938	607-783 Mendon Rd, WSO	Woonsocket	Integrity	1165	2230	14
90000226149	Flora Av, WSO	Woonsocket	Integrity	3680	3680	54
90000226151	Sidney Av, WSO	Woonsocket	Integrity	2240	2165	37
90000225923	Columbus Av, PAW	Pawtucket	Integrity	1715	1715	25
90000225847	Fales St, CFL	Central Falls	Integrity	1145	1145	22
90000225867	Perry St, CFL	Central Falls	Integrity	4630	4360	96
90000211503	River Rd, LNC	Lincoln	Integrity	3995	4025	52
90000225844	Walker St, LNC	Lincoln	Integrity	2990	2975	12
90000225846	Gardiner Av, LNC	Lincoln	Integrity	500	340	5
90000225941	Borah St, NPV	North Providence	Integrity	5805	5590	93
90000194318	Morse Av, NSF	North Smithfield	Integrity	5000	6685	45
90000225889	231-319 Mendon Av, PAW	Pawtucket	Integrity	2315	2335	29
90000225895	Lowden St, PAW	Pawtucket	Integrity	3715	3905	67
90000225904	1088-1131 Main St, PAW	Pawtucket	Integrity	1410	1360	0
90000225921	Memorial Dr, PAW	Pawtucket	Integrity	3190	3100	65
90000225926	Whitman St, PAW	Pawtucket	Integrity	1870	1805	29
90000226085	Gorizia St, PAW	Pawtucket	Integrity	1765	1765	32
90000225937	Lefrancois Blvd, WSO	Woonsocket	Integrity	2365	2325	26
90000226113	Dewey St, WSO	Woonsocket	Integrity	2040	1945	34
90000226114	Park Pl, WSO	Woonsocket	Integrity	6465	8640	107
90000226116	Lincoln St, WSO	Woonsocket	Integrity	2540	2455	42
90000226144	West St, WSO	Woonsocket	Integrity	3235	3305	54
90000229862	Third Av, WSO	Woonsocket	Integrity	7385	10065	82
90000229863	Second Av, WSO	Woonsocket	Integrity	3480	5840	75
90000225872	Josephine Av, EPV	East Providence	Integrity	580	545	10
90000204632	Scenic Dr, WWK	Warwick	Integrity	5200	5200	64
90000225940	Watson St, WWK	Warwick	Integrity	4125	4215	58
90000225928	885-1092 Main St, WAN	Warren	Integrity	2935	2995	18
90000225848	143-212 Greenwood St, CRA	Cranston	Integrity	3355	3315	68
90000225860	W Hill Dr, CRA	Cranston	Integrity	4780	4705	98
90000225946	Sterling St, EPV	East Providence	Integrity	2735	2655	51
90000225951	Pavilion Av, EPV	East Providence	Integrity	2920	2945	62
90000226076	65-153 Manton Av, PVD	Providence	Integrity	3155	4235	27
90000230891	Narragansett Av, PVD	Providence	Integrity	4055	4430	40
90000230974	697-908 Eddy St, PVD	Providence	Integrity	6630	6530	53
90000230676	Thames St (Section 2) - CISBOT, NPR	Newport	Integrity	1400	1400	0
90000230868	Thames St (Section 3) - CISBOT, NPR	Newport	Integrity	1260	1260	0
90000230797	Petteys Av (16" 10#) - LINING, PVD	Providence	Integrity	1830	1830	4
90000230689	Russell St - CISBOT, PVD	Providence	Integrity	1730	1730	0
90000230870	485-684 Chalkstone St - CISBOT, PVD	Providence	Integrity	2015	2015	0
90000230874	55-189 Canal St - LINING, PVD	Providence	Integrity	540	540	0
90000230801	Petteys Av (36" LP) - CISBOT, PVD	Providence	Integrity	2035	2035	0

Prepared by or under the supervision of: Nathan Kocon

Division 1-19

Request:

Regarding the proposed projects listed in Div 1-18, please provide a breakdown of the number of leak prone services that will be replaced in conjunction with the 122.6 miles of leak prone main to be abandoned.

Response:

The projects listed in Attachment DIV 1-18 call for the replacement or tie-over of 1,818 services. There are another 6,815 services associated with projects listed in Attachment Division 1-16-1. The Company is not able to determine how many of these services are leak prone; however, there are an average of approximately 47 leak prone services per mile of leak prone main, so it is expected that approximately 5,700 leak prone services will be replaced during the 21-month FY 2024 period (combination of 9-month CY 2023 and CY 2024).

Prepared by or under the supervision of: Phil LaFond

Division 1-20

Request:

Provide the current population of leak prone services by material type and decade of installation in risk ranking order.

Response:

Please see table below for the requested information organized by material and decade of installation in risk ranking order. The category "Other" refers to leak prone services for which the Company does not have a record of the material type.

Material	**Installed year**	**Count of LPP services**	**Total**
Cast/Wrought Iron	Unknown	4	**25**
	Pre 1940	13	
	1940s	2	
	1950s	3	
	1960s	2	
	2000s	1	
Unprotected Bare Steel	Unknown	4,509	**37,915**
	Pre 1940	16,273	
	1940s	4,265	
	1950s	6,228	
	1960s	5,495	
	1970s	1,031	
	1980s	47	
	1990s	61	
	2000s	4	
	2010s	2	
Unprotected Coated Steel	Unknown	218	**5,496**
	Pre 1940	29	
	1940s	10	
	1950s	42	
	1960s	4,549	
	1970s	648	
	Unknown	38	**71**

Prepared by or under the supervision of: Barry Foster

Division 1-20, page 2

Material	Installed year	Count of LPP services	Total
Copper	1950s	2	
	1960s	27	
	1970s	2	
	1980s	1	
	1990s	1	
Other	Unknown	913	**951**
	Pre 1940	1	
	1950s	1	
	1960s	2	
	1970s	7	
	1980s	3	
	1990s	1	
	2000s	1	
	2010s	22	
Grand Total		**4,458**	

Division 1-21

Request:

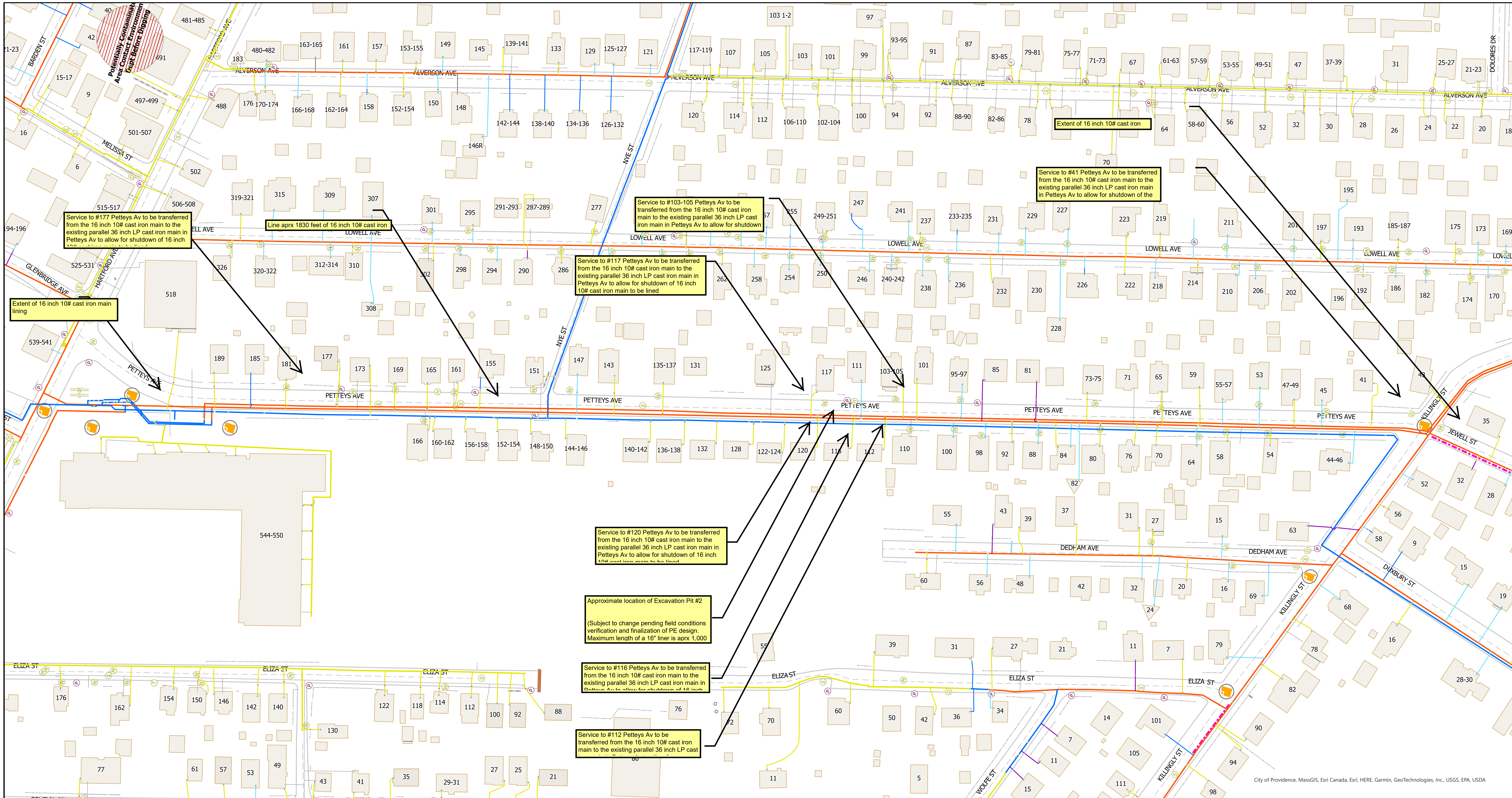
Regarding the Large Diameter LPCI Program on Page 25, provide the details and a site plan for the Petteys Avenue Lining Project.

Response:

The Petteys Avenue (16 inch 10#) – LINING, PVD project is being developed to line approximately 1,830 feet of 16 inch 10# cast iron main in Petteys Avenue from 189 Petteys Avenue to Killingly Street. To line this segment of main, 3 excavations will be required for the sending and receiving of the liner: one located at 189 Petteys Avenue, one located at the intersection of Petteys Avenue and Killingly Street, and one located at a yet to be determined location between 111 Petteys Avenue and 125 Petteys Avenue.

The location of this pit is still undetermined as the PE design process for this project is still ongoing and will be determined based on field conditions. In order to allow for the shutdown of the 16 inch 10# cast iron main to be lined, the following services will need to be transferred over to the parallel 36 inch LP cast iron main in Petteys Avenue: 41, 103-105, 112, 116, 117, 120, and 177 Petteys Avenue. Please see Attachment Division 1-21 for an overview map of the project.

▪ NOT FOR CONSTRUCTION, SEE PE-STAMPED DESIGN DRAWINGS.
▪ PRESSURE GAUGES ARE REQUIRED AT ALL MAINS FOR ALL TIE-INS. REFER TO GCON-02001 PROCEDURE.
▪ CHECK ELECTRONIC MAPPING SYSTEM FOR MOST CURRENT MAPPING INFORMATION.



90000230797 - Petteys Av (16" 10#) - LINING, PVD

As part of the CIMNLINING program, Distribution Asset Management recommends the lining of aprx:
- 1830 feet of 16 inch 10# cast iron in Petteys Av from #189 Petteys Av to Killingly St
- Relay/transfer services to #41, #103-105, #112, #116, #117, #120, and #177 Petteys Av from the 16 inch 10# cast iron main to be lined to the existing parallel 36 inch LP cast iron main.
- Work scheduled due to leak score

NOTE: The location of surface and underground objects shown are not warranted to be correct.

N

90 45 0 90 Feet

DATE	11/14/2022

Division 1-22

Request:

Regarding the Large Diameter LPCI Program on Pages 25-26, provide a list of the proposed six Cast-Iron Sealing Robot (CISBOT) projects. Please include the description, the location and a cost estimate for each project.

Response:

WO# 90000230676 – Thames Street (Section 2) – CISBOT, Newport

Project Description
As part of the Large Diameter Cast Iron Rehabilitation Program, Distribution Asset Management recommends the use of CISBOT to seal approximately:

- 720 feet of 16-inch LP cast iron (~60 joints) in Thames Street from 302 Thames Street to 372 Thames Street (North Extent: Drip at 302 Thames Street. South Extent: Drip at 372 Thames Street)
- 680 feet of 16-inch LP cast iron (~56 joints) in Thames Street from 372 Thames Street to Howard Street (North Extent: Drip at 372 Thames Street. South Extent: Howard Street)

Total Excavations: 2
Total Joints: 116

Cost Estimate
$757,000

Division 1-22, page 2

WO# 90000230868 – Thames Street (Section 3) – CISBOT, Newport

Project Description
As part of the Large Diameter Cast Iron Rehabilitation Program, Distribution Asset Management recommends the use of CISBOT to seal approximately:

- 590 feet of 16-inch LP cast iron (~49 joints) in Thames Street from Howard Street to 490 Thames Street (North Extent: Howard Street. South Extent: Drip at 490 Thames Street)
- 670 feet of 16-inch LP cast iron (~56 joints) in Thames Street from 490 Thames Street to 548 Thames Street (North Extent: Drip at #490 Thames Street. South Extent: Valve at 548 Thames Street)

Total Excavations: 2
Total Joints: 105

Cost Estimate
$681,500

Division 1-22, page 3

WO# 90000230689 – Russell Street – CISBOT, Providence

Project Description
As part of the Large Diameter Cast Iron Rehabilitation Program, Distribution Asset Management recommends the use of CISBOT to seal approximately:

- 335 feet of 20-inch 7 psi cast iron (~28 joints) in Melrose Street from 237-239 Melrose Street to Russell Street (North Extent: the 16-inch coated steel tee at the outlet of the 99 psi to LP regulator station nearby 237-239 Melrose Street. South Extent: the 20 -inch cast iron 90-degree elbow at the intersection of Melrose Street and Russell Street)
- 700 feet of 12-inch 7 psi cast iron (~58 joints) in Russell Street from Melrose Street to Elmwood Avenue (East Extent: the 20-inch cast iron drip nearby #269 Melrose Street. West Extent: the 20-inch cast iron drop near the intersection of Russell Street and Elmwood Avenue)
- 470 feet of 20-inch 7 psi cast iron (~39 joints) in Russell Street from Elmwood Avenue to #128 Narragansett Avenue (East Extent: the 20-inch cast iron drip near the intersection of Russell Street and Elmwood Avenue. West Extent: the 20-inch cast iron 45-degree elbow near the RR crossing to the West of Elmwood Avenue)
- 225 feet of 20-inch 7 psi cast iron (~19 joints) in Russell Street from 128 Narragansett Avenue to Narragansett Avenue (East Extent: 20-inch cast iron 45-degree elbow near the RR crossing to the West of Elmwood Avenue. West Extent: 20-inch cast iron tee in the intersection of Russell Street and Narragansett Avenue)

Total excavations: 4
Total Joints: 144

Cost Estimate
$1,095,000

Prepared by or under the supervision of: Corey Hogg

Division 1-22, page 4

WO# 90000230870 – 485-684 Chalkstone Street – CISBOT, Providence

Project Description
As part of the Large Diameter Cast Iron Rehabilitation Program, Distribution Asset Management recommends the use of CISBOT to seal approximately:

- 1120 feet of 30-inch LP cast iron (~93 joints) in Chalkstone Avenue from Richter Street to Smith Street (Western Extent: Richter Street. Eastern Extent: 45-degree elbow near the intersection of Chalkstone Avenue and Smith Street)
- 895 feet of 30-inch LP cast iron (~74 joints) in Chalkstone Avenue from Smith Street to Candance Street (Western Extent: 45-degree elbow near the intersection of Chalkstone Avenue and Smith Street. Eastern Extent: Drip in the intersection of Chalkstone Avenue and Candace Street)

Total Excavations: 2
Total Joints: 167

Cost Estimate
$1,285,500

Prepared by or under the supervision of: Corey Hogg

Division 1-22, page 5

WO# 90000230874 – 55-189 Canal Street – CISBOT, Providence

Project Description
As part of the Large Diameter Cast Iron Rehabilitation Program, Distribution Asset Management recommends the use of CISBOT to seal approximately:

- 540 feet of 24-inch LP cast iron in Canal Street from 189 Canal Street to Washington Place

Total Excavations: 2
Total Joints: 45

Cost Estimate
$345,000

Division 1-22, page 6

WO# 90000230801 – Petteys Avenue (36" LP) – CISBOT, Providence

Project Description
As part of the Large Diameter Cast Iron Rehabilitation Program, Distribution Asset Management recommends the use of CISBOT to seal approximately:

- 2035 feet of 36-inch LP cast iron in Petteys Avenue from Hartford Avenue to Killingly Street (North Extent: 36-inch cast iron elbow at the intersection of Petteys Avenue and Hartford Avenue. South Extent: 36-inch cast iron elbow at the intersection of Petteys Avenue and Killingly Street)

Total Excavations: 2
Total Joints: 170

Cost Estimate
$1,3000,000

Division 1-23

Request:

Regarding the large diameter main rehabilitation, explain how the Company determines when a main is relined vs. using the CISBOT method of joint sealing.

Response:

To perform the lining process, the large diameter cast iron main to be lined must be shut down and temporarily taken out of service. CISBOT does not require mains be shut down to launch the robot into the main and perform the joint sealing process. When a segment is selected to be addressed under the large diameter rehabilitation program, it is evaluated first as a potential lining job as that is the preferred method to address these segments. While lining is the preferred method, there are several factors that often make segments either practically or economically unfeasible to line and, in these cases, CISBOT must be used instead. These factors are as follows:

1) As was mentioned, to perform the lining process, mains are shut down and taken out of service. Given that these mains are large in diameter and, therefore, support larger flows of gas, they are often crucial to the overall pressure health of the system. Rhode Island Energy's Operations Engineering team analyzes each main to determine whether it can or cannot be taken out of service for a period of time to perform the lining work. Typically, it is possible to find a shutdown window in the warmer months when gas demand is not as high; however, some mains may be so crucial to the reliability of the system that they cannot be taken out of service safely for any period of time.
2) An example of the point mentioned in bullet point 1) would be a single fed dead end main (or system) servicing a side street (or set of side streets) teeing off of a large diameter main. If the large diameter main is shut down, all customers on the single fed main/system would lose their gas supply.
3) If a large diameter main has a large number of services being fed off of it, it is typically not a good candidate for lining as shutting down the main would in turn cause all of these customers to lose service. There are cases where this is not a total disqualifier. If there is a main parallel in the street to the large diameter cast iron main to be lined that can support the load of the existing services being fed off the lining candidate, the services can be transferred to the parallel main ahead of the main shutdown. In some cases, short parallel main installations can be done to pick up a small number of customers and make the shutdown possible, however, longer installations end up becoming more of a cost burden.

4) The location of excavations for lining are less flexible than they are for CISBOT, and field conditions can make lining unfeasible for this reason. The liner must be
5) launched at one end and received at the other, so there are specific locations where excavation pits would be required. Conversely, with CISBOT, the robot can move in either direction from a launch pit. If field conditions dictate moving a launch pit, all the joints can still be reached from that location though the direction and distance of the robots travel may change.

In addition to the above, whether a candidate main is to be addressed using CISBOT or lining, segments are evaluated by Rhode Island Energy's Long-Term Planning team to ensure they cannot instead just be relayed with 12" (or smaller) PE or abandoned entirely before proceeding.

Division 1-24

Request:

What was the "average cost per service" for replacing proactive services in the Proactive Service Replacement Program for FY 2022 and FY 2023? How many services were replaced in FY 2022 and FY 2023 to date?

Response:

In FY 2022 the average cost per service was approximately $7,100, and a total of 56 services were replaced.

In FY 2023 to date, the average cost per service is approximately $5,500, and 32 services have been replaced so far.

Both the FY 2022 and FY 2023 cost include restoration costs for work in the preceding fiscal year. The FY 2023 year to date cost does not include final restoration costs for all FY 2023 projects since not all work has been completed.

Prepared by or under the supervision of: Phil Lafond

Division 1-25

Request:

Provide an updated list of the isolated services (leak prone services on non-leak prone pipe) by location, material type, and date of installation in risk ranking order.

Response:

Please see Attachment DIV 1-25 for the updated List of Isolated Services by risk rank order. Copper Services do not have a risk rank but fall below Bare Steel Services and Wrapped Steel Services. Service replacements are scheduled in order of Customer responses to the Company's outreach efforts.

Prepared by or under the supervision of: Phil Lafond

Attachment DIV 1-25		List of Isolated Services (leak prone services on non-leak prone pipe)				
ID	DATE_INST	MATERIAL	Street address	ZIP	City/Town	Priority
39559519	1/1/1911	Bare Steel	221 SEVENTH AVE	02895	Woonsocket	478
39596179	1/1/1916	Bare Steel	68 NORTHEAST ST	02895	Woonsocket	478
413870147	12/4/1914	Bare Steel	183 LINWOOD AVE	02907	Providence	478
413870165	12/4/1914	Bare Steel	187 LINWOOD AVE	02907	Providence	478
413870286	7/8/1914	Bare Steel	174 LINWOOD AVE	02907	Providence	478
39537764	1/1/1916	Bare Steel	105 HAMLET AVE	02895	Woonsocket	427
416255034	5/10/1917	Bare Steel	437 W FOUNTAIN ST	02903	Providence	427
34027806	10/17/1921	Bare Steel	87 HADWIN ST	02863	Central Falls	417
36348625	1/1/1923	Bare Steel	21 MCCUSKER CT	02860	Pawtucket	417
10518386	1/1/1940	Bare Steel	333 OAKLAWN AVE	02920	Cranston	398
39511057	1/1/1940	Bare Steel	Woon Pump Station, Highland Corporate Drive	02895	Woonsocket	398
478627916	1/1/1941	Bare Steel	208 Beachview Terrace	02842	Middletown	398
281297929	3/17/1958	Bare Steel	346 Middle Highway	02806	Barrington	390
281304841	1/26/1959	Bare Steel	310 Middle Highway	02806	Barrington	390
296149720	1/1/1940	Bare Steel	16 ANTHONY ST	02914	East Providence	389
413870068	1/1/1940	Bare Steel	198 LINWOOD AVE	02907	Providence	389
413870277	1/1/1940	Bare Steel	172 LINWOOD AVE	02907	Providence	389
416255016	1/1/1940	Bare Steel	433 W FOUNTAIN ST	02903	Providence	389
531730835	1/1/1940	Bare Steel	2235 Cranston St	02920	Cranston	389
477969233	1/1/1932	Bare Steel	115 Carroll Ave	02840	Newport	380
478167243	1/1/1936	Bare Steel	26 Freebody St	02840	Newport	380
36236046	1/1/1940	Bare Steel	156 BROAD ST	02860	Pawtucket	374
37074767	1/1/1940	Bare Steel	3 Farnwoth Dr	02865	Lincoln	374
183912909	1/1/1940	Bare Steel	64 OCEAN AVE	02905	Providence	374
413870212	1/1/1940	Bare Steel	195 LINWOOD AVE	02907	Providence	374
413870246	1/1/1940	Bare Steel	168 LINWOOD AVE	02907	Providence	374
414596258	1/1/1940	Bare Steel	53 BANCROFT ST	02909	Providence	374
34039076	1/1/1921	Bare Steel	769 LONSDALE AVE	02863	Central Falls	367
36157588	5/20/1926	Bare Steel	193 NEWELL AVE	02860	Pawtucket	367
36179626	1/1/1929	Bare Steel	24 SPRING ST	02860	Pawtucket	367
36203481	1/1/1925	Bare Steel	220 DUNNELL AVE	02860	Pawtucket	367
36209890	1/1/1929	Bare Steel	24-28 Spring St	02860	Pawtucket	367
36233648	1/1/1928	Bare Steel	35 SPRING ST	02860	Pawtucket	367
36245271	1/1/1928	Bare Steel	88 BELMONT ST	02860	Pawtucket	367
36305333	1/1/1922	Bare Steel	98 BENEFIT ST	02861	Pawtucket	367
36320004	1/1/1929	Bare Steel	62 SPRING ST	02860	Pawtucket	367
37065158	1/1/1925	Bare Steel	3 COBBLE-HILL RD	02865	Lincoln	367
37071592	1/1/1925	Bare Steel	114 OLD-MAIN ST	02838	Manville	367

Attachment DIV 1-25		List of Isolated Services (leak prone services on non-leak prone pipe)				
ID	DATE_INST	MATERIAL	Street address	ZIP	City/Town	Priority
37082315	1/1/1927	Bare Steel	44 PLEASANT ST	02865	Lincoln	367
38297787	1/1/1929	Bare Steel	98 HIGH ST	02864	Cumberland	367
38299928	1/1/1926	Bare Steel	105 HIGH ST	02864	Cumberland	367
38301386	1/1/1925	Bare Steel	119 HIGH ST	02864	Cumberland	367
38303813	1/1/1926	Bare Steel	107 HIGH ST	02864	Cumberland	367
38353365	1/1/1925	Bare Steel	182 DEXTER ST	02864	Cumberland	367
38365248	1/1/1926	Bare Steel	22 Eli St	02864	Cumberland	367
38366607	1/1/1926	Bare Steel	23 Eli St	02864	Cumberland	367
38369303	1/1/1925	Bare Steel	18 ELI ST	02864	Cumberland	367
39536636	1/1/1922	Bare Steel	32 WELLES ST	02895	Woonsocket	367
39550634	1/1/1925	Bare Steel	31 WELLES ST	02895	Woonsocket	367
281482480	12/20/1924	Bare Steel	3 KNOWLTON ST	02915	Riverside	367
297178392	10/2/1929	Bare Steel	68 North Olney St	02919	Johnston	367
414160197	5/31/1924	Bare Steel	88-90 Gordon Ave	02905	Providence	367
414864652	5/11/1921	Bare Steel	365 ATWELLS AVE	02903	Providence	367
531747708	8/13/1923	Bare Steel	18 SCOTT ST	02920	Cranston	367
274515193	1/5/1950	Bare Steel	9 HASWELL ST	02891	Westerly	352
296997140	2/16/1956	Bare Steel	7 RICE ST	02919	Johnston	352
36252415	1/1/1926	Bare Steel	318 Lafayette St	02860	Pawtucket	350
36278897	1/1/1928	Bare Steel	27 SPRING ST	02860	Pawtucket	350
36310700	1/1/1926	Bare Steel	592 PAWTUCKET AVE	02860	Pawtucket	350
39550351	1/1/1922	Bare Steel	308 CARRINGTON AVE	02895	Woonsocket	350
119407484	10/1/1928	Bare Steel	84 PROSPECT ST	02906	Providence	350
119855670	5/16/1928	Bare Steel	112 Prospect St	02906	Providence	350
34029123	1/1/1931	Bare Steel	24 W ST	02863	Central Falls	329
34030804	1/1/1936	Bare Steel	1060 LONSDALE AVE	02863	Central Falls	329
36165348	1/1/1935	Bare Steel	33 COLUMBIA AVE	02860	Pawtucket	329
36260582	1/1/1937	Bare Steel	208 RANDALL ST	02860	Pawtucket	329
36265644	1/1/1938	Bare Steel	104 FAIRVIEW AVE	02860	Pawtucket	329
36305875	1/1/1937	Bare Steel	204 RANDALL ST	02860	Pawtucket	329
36325417	1/1/1938	Bare Steel	109 FAIRVIEW AVE	02860	Pawtucket	329
37078429	1/1/1936	Bare Steel	36 GRANDVIEW AVE	02865	Lincoln	329
38300850	1/1/1931	Bare Steel	109 HIGH ST	02864	Cumberland	329
38361899	1/1/1935	Bare Steel	7 Eli St	02864	Cumberland	329
38364625	1/1/1932	Bare Steel	9 Eli St	02864	Cumberland	329
39595990	1/1/1938	Bare Steel	78 Hamlet Ave	02895	Woonsocket	329
416254955	10/17/1938	Bare Steel	425 W FOUNTAIN ST	02903	Providence	329
478242951	1/1/1942	Bare Steel	180 Annandale Rd	02840	Newport	326

Attachment DIV 1-25		List of Isolated Services (leak prone services on non-leak prone pipe)				
ID	DATE_INST	MATERIAL	Street address	ZIP	City/Town	Priority
33780843	1/1/1940	Bare Steel	3 BORAH ST	02904	Providence	323
34015849	1/1/1940	Bare Steel	48 W ST	02863	Central Falls	323
36168320	1/1/1940	Bare Steel	30 COLUMBIA AVE	02860	Pawtucket	323
36239067	1/1/1949	Bare Steel	110 FORTIN AVE	02860	Pawtucket	323
36350193	1/1/1942	Bare Steel	30 APPLETON AVE	02860	Pawtucket	323
37029440	1/1/1941	Bare Steel	225-227 Front St	02865	Lincoln	323
37034975	1/1/1945	Bare Steel	5 Church Lane	02838	Manville	323
37080497	1/1/1949	Bare Steel	141-143 Lonsdale Main St	02865	Lincoln	323
38345207	1/1/1949	Bare Steel	177 DEXTER ST	02864	Cumberland	323
38346525	1/1/1949	Bare Steel	232 DEXTER ST	02864	Cumberland	323
38361170	1/1/1945	Bare Steel	13 Eli St	02864	Cumberland	323
38363909	1/1/1945	Bare Steel	15 Eli St	02864	Cumberland	323
296997149	8/10/1949	Bare Steel	9 RICE ST	02919	Johnston	323
296997194	1/1/1940	Bare Steel	28 RICE ST	02919	Johnston	323
413870156	12/22/1947	Bare Steel	184 LINWOOD AVE	02907	Providence	323
478151900	1/1/1940	Bare Steel	589 BELLEVUE AVE	02840	Newport	323
119157316	10/31/1962	Bare Steel	253 SUMMIT AVE	02906	Providence	320
295663060	2/1/1950	Bare Steel	84 TYLER ST	02888	Warwick	320
297188537	10/31/1966	Bare Steel	34 Argonne St	02919	Johnston	320
531664999	5/29/1969	Bare Steel	135 MARLOW ST	02920	Cranston	320
36178718	1/1/1931	Bare Steel	56 ARMISTICE BLVD	02860	Pawtucket	312
36304991	1/1/1931	Bare Steel	55 ARMISTICE BLVD	02860	Pawtucket	312
36338171	1/1/1937	Bare Steel	297 LAFAYETTE ST	02860	Pawtucket	312
38345216	1/1/1935	Bare Steel	226 DEXTER ST	02864	Cumberland	312
274462912	4/14/1970	Bare Steel	131 CROSS ST	02891	Westerly	308
39579230	1/1/1940	Bare Steel	531 HARRIS AVE	02895	Woonsocket	306
274515403	1/1/1940	Bare Steel	56 SPRUCE ST	02891	Westerly	306
36195541	1/1/1956	Bare Steel	99 FORTIN AVE	02860	Pawtucket	301
36202287	1/1/1955	Bare Steel	278 LAFAYETTE ST	02860	Pawtucket	301
36229273	1/1/1958	Bare Steel	76 SPRING ST	02860	Pawtucket	301
36263521	1/1/1958	Bare Steel	57 Spring St	02860	Pawtucket	301
36311717	1/1/1958	Bare Steel	54 SPRING ST	02860	Pawtucket	301
36314928	2/7/1951	Bare Steel	41 COLUMBIA AVE	02860	Pawtucket	301
36319814	1/1/1953	Bare Steel	16 APPLETON AVE	02860	Pawtucket	301
36352710	1/1/1958	Bare Steel	53 ANDERTON AVE	02860	Pawtucket	301
37040973	1/1/1957	Bare Steel	1 PLEASANT-VIEW AVE	02865	Lincoln	301
37052769	1/1/1954	Bare Steel	44 NEW RD	02838	Manville	301
37060157	1/1/1953	Bare Steel	174 Lonsdale St	02865	Lincoln	301

Attachment DIV 1-25		List of Isolated Services (leak prone services on non-leak prone pipe)				
ID	DATE_INST	MATERIAL	Street address	ZIP	City/Town	Priority
37066793	1/1/1954	Bare Steel	32 KNOWLES ST	02865	Lincoln	301
38344574	1/1/1957	Bare Steel	180 Dexter St	02864	Cumberland	301
38346534	1/1/1957	Bare Steel	165 DEXTER ST	02864	Cumberland	301
39511980	1/1/1959	Bare Steel	84 NORTHEAST ST	02895	Woonsocket	301
39536313	1/1/1957	Bare Steel	60 WELLES ST	02895	Woonsocket	301
39536583	1/1/1955	Bare Steel	113 HAZEL ST	02895	Woonsocket	301
39593361	1/1/1953	Bare Steel	122 BAXTER ST	02895	Woonsocket	301
478496607	1/1/1957	Bare Steel	11 CLARKE ST	02840	Newport	301
531629998	2/7/1951	Bare Steel	37 ROYER ST	02920	Cranston	301
36271217	1/1/1958	Bare Steel	7 Denver St	02860	Pawtucket	284
36274780	1/1/1958	Bare Steel	52 SPRING ST	02860	Pawtucket	284
36216510	1/1/1966	Bare Steel	20 HYDE AVE	02861	Pawtucket	269
36353719	1/1/1966	Bare Steel	234 SENECA AVE	02860	Pawtucket	269
37048999	1/1/1963	Bare Steel	112 OLD-MAIN ST	02838	Manville	269
38299416	1/1/1965	Bare Steel	119 HIGH ST	02864	Cumberland	269
38365966	1/1/1962	Bare Steel	10 Eli St	02864	Cumberland	269
39513958	1/1/1963	Bare Steel	227 CHAPEL ST	02895	Woonsocket	269
39593968	1/1/1969	Bare Steel	123 BAXTER ST	02895	Woonsocket	269
39598544	1/1/1967	Bare Steel	33 BREAULT AVE	02895	Woonsocket	269
413870077	3/17/1966	Bare Steel	199 LINWOOD AVE	02907	Providence	269
38365180	1/1/1939	Bare Steel	50 MT-PLEASANT-VW AVE	02864	Cumberland	260
281286209	1/7/1931	Bare Steel	507 MIDDLE HWY	02806	Barrington	260
39591600	1/2/1970	Bare Steel	309 Baxter St	02895	Woonsocket	258
478232650	1/1/1940	Bare Steel	176 MAPLE AVE	02842	Middletown	254
33780596	1/1/1966	Bare Steel	1108 CHARLES ST	02904	Providence	252
39517882	1/1/1966	Bare Steel	457 DIAMOND-HILL RD	02895	Woonsocket	252
38093048	1/1/1959	Bare Steel	69 PROVIDENCE PIKE	02896	North Smithfield	230
297006935	6/29/1971	Wrapped Steel	46 LAFAYETTE ST	02919	Johnston	214
38307784	1/1/1957	Bare Steel	30 MEETING ST	02864	Cumberland	212
15884293	1/1/1940	Wrapped Steel	2 HIGH ST	02809	Bristol	212
33778708	1/1/1966	Bare Steel	66 ATLANTIC AVE	02904	Providence	196
38312094	1/1/1968	Bare Steel	72 FAIRHAVEN RD	02864	Cumberland	196
38339837	1/1/1968	Bare Steel	11 HARDWICK ST	02864	Cumberland	196
38344531	1/1/1969	Bare Steel	296 Mendon St	02864	Cumberland	196
41968043	11/23/1963	Bare Steel	6665-6667 Post Rd	02852	North Kingstown	196
350535718	5/29/1968	Bare Steel	157 WAKEFIELD ST	02893	West Warwick	196
350535864	5/31/1968	Bare Steel	149 WAKEFIELD ST	02893	West Warwick	196
478378482	1/1/1962	Bare Steel	26 BROOKDALE RD	02842	Middletown	196

Attachment DIV 1-25		List of Isolated Services (leak prone services on non-leak prone pipe)				
ID	DATE_INST	MATERIAL	Street address	ZIP	City/Town	Priority
531577732	12/27/1965	Bare Steel	30 TURNER AVE	02920	Cranston	196
38339545	1/1/1971	Bare Steel	19 HARDWICK ST	02864	Cumberland	184
176596	4/8/1968	Wrapped Steel	14 CRAIG RD	02886	Warwick	96
176605	4/23/1968	Wrapped Steel	356 TOLLGATE RD	02886	Warwick	96
5181116	12/27/1966	Wrapped Steel	16 FRATERNITY CIR	02881	Kingston	96
183464456	2/24/1961	Wrapped Steel	40 RED-CEDAR DR	02920	Cranston	96
274087525	5/4/1967	Wrapped Steel	39 King St	02886	Warwick	96
274103288	10/23/1969	Wrapped Steel	30 GUILFORD DR	02886	Warwick	96
274244335	2/19/1963	Wrapped Steel	49 CARLTON AVE	02889	Warwick	96
281261486	8/30/1968	Wrapped Steel	16 QUINCY-ADAMS RD	02806	Barrington	96
281330554	11/23/1965	Wrapped Steel	81 PRINCES-HILL AVE	02806	Barrington	96
297169421	9/8/1965	Wrapped Steel	1854 ATWOOD AVE	02919	Johnston	96
531567788	6/5/1968	Wrapped Steel	26 TURNER AVE	02920	Cranston	96
531589923	9/2/1966	Wrapped Steel	218 GARDEN-HILLS DR	02920	Cranston	96
531745652	12/6/1965	Wrapped Steel	165 CURTIS ST	02920	Cranston	96
531936452	11/2/1964	Wrapped Steel	73 ELLISON ST	02920	Cranston	96
531936461	10/10/1964	Wrapped Steel	78 ELLISON ST	02920	Cranston	96
416111462	11/30/1967	Wrapped Steel	770 WESTMINSTER ST	02903	Providence	86
183116250	6/9/1971	Wrapped Steel	51 FAIRWOOD DR	02920	Cranston	84
274098262	7/14/1970	Wrapped Steel	7 Eastman St	02886	Warwick	84
531745701	11/7/1970	Wrapped Steel	95 CURTIS ST	02920	Cranston	84
13667007	1/1/1940	Coated Steel	10 SISSON ST	2885	Warren	
38358587	1/1/1966	Coated Steel	10 STATE ST	2885	Warren	
38357607	1/1/1965	Coated Steel	101 WATER ST	2885	Warren	
38344781	1/1/1967	Coated Steel	104 WATER ST	2885	Warren	
38362487	1/1/1965	Coated Steel	11 JOHNSON ST	2885	Warren	
13590603	1/1/1940	Coated Steel	11 WESTMINSTER ST	2885	Warren	
38358179	1/1/1965	Coated Steel	110 WATER ST	2885	Warren	
13663603	1/1/1940	Coated Steel	118 WATER ST	2885	Warren	
38362643	1/1/1965	Coated Steel	12 COMPANY ST	2885	Warren	
38356731	1/1/1965	Coated Steel	12 JOHNSON ST	2885	Warren	
40144257	1/1/1940	Coated Steel	124 WATER ST	2885	Warren	
38348291	1/1/1966	Coated Steel	125 WATER ST	2885	Warren	
38350467	1/1/1966	Coated Steel	135 WATER ST	2885	Warren	
13667654	1/1/1940	Coated Steel	146 WATER ST	2885	Warren	
38345776	10/21/1966	Coated Steel	147 WATER ST	2885	Warren	
14047712	4/19/1973	Coated Steel	15 SISSON ST	2885	Warren	
38364386	1/1/1965	Coated Steel	154 WATER ST	2885	Warren	

Attachment DIV 1-25		List of Isolated Services (leak prone services on non-leak prone pipe)				
ID	DATE_INST	MATERIAL	Street address	ZIP	City/Town	Priority
13667770	1/1/1940	Coated Steel	155 WATER ST	2885	Warren	
38356313	1/1/1965	Coated Steel	164 WATER ST	2885	Warren	
13667130	1/1/1940	Coated Steel	17 STATE ST	2885	Warren	
38346277	1/1/1966	Coated Steel	172 WATER ST	2885	Warren	
13594587	1/1/1940	Coated Steel	177 WATER ST	2885	Warren	
38358851	1/1/1965	Coated Steel	178 WATER ST	2885	Warren	
38343682	1/1/1966	Coated Steel	184 WATER ST	2885	Warren	
13703880	1/1/1940	Coated Steel	193 WATER ST	2885	Warren	
38359332	1/1/1965	Coated Steel	196 WATER ST	2885	Warren	
38357442	1/1/1965	Coated Steel	198 WATER ST	2885	Warren	
13666490	1/1/1940	Coated Steel	23 COMPANY ST	2885	Warren	
38358440	1/1/1966	Coated Steel	236 WATER ST	2885	Warren	
39018749	1/1/1965	Coated Steel	24 WESTMINSTER ST	2885	Warren	
13591510	1/1/1940	Coated Steel	26 STATE ST	2885	Warren	
39018735	1/1/1965	Coated Steel	262 WATER ST	2885	Warren	
38350451	1/1/1967	Coated Steel	27 STATE ST	2885	Warren	
38363569	1/1/1965	Coated Steel	296 WATER ST	2885	Warren	
38345378	1/1/1966	Coated Steel	30 STATE ST	2885	Warren	
38344610	1/1/1966	Coated Steel	317 WATER ST	2885	Warren	
38348477	1/1/1967	Coated Steel	35 STATE ST	2885	Warren	
38343087	1/1/1966	Coated Steel	350 WATER ST	2885	Warren	
38346834	1/1/1966	Coated Steel	376 WATER ST	2885	Warren	
38347880	1/1/1966	Coated Steel	49 WATER ST	2885	Warren	
38348603	1/1/1967	Coated Steel	53 STATE ST	2885	Warren	
39018742	1/1/1966	Coated Steel	55 STATE ST	2885	Warren	
38348520	1/1/1966	Coated Steel	57 BROAD ST	2885	Warren	
38347806	1/1/1966	Coated Steel	6 WESTMINSTER ST	2885	Warren	
38347135	1/1/1967	Coated Steel	60 WATER ST	2885	Warren	
38365466	1/1/1966	Coated Steel	72 WATER ST	2885	Warren	
38343939	1/1/1966	Coated Steel	8 COMPANY ST	2885	Warren	
38376751	1/1/1966	Coated Steel	8 COMPANY ST	2885	Warren	
38347691	1/1/1967	Coated Steel	Town Common Building, State St	2885	Warren	
38361417	1/1/1965	Coated Steel	60 SLEEPY-HOLLOW DR	2864	Cumberland	
13591425	1/1/1940	Coated Steel	73 Sun Valley Rd	2864	Cumberland	

Division 1-26

Request:

What is the Company's plan to address leak prone services on newly rehabilitated (CISBOT or lining) large diameter mains?

Response:

As discussed in the Company's response to Division 1-23, in order to line a large diameter cast iron main, the main must be shut down and taken out of service. As a part of this process, any services which are connected to mains that are scheduled to be lined must be transferred over to an alternative source so that the customer's gas service is not disrupted during the shutdown. As a part of this process, any leak prone services amongst these would be relayed with polyethylene.

Currently, the scope of CISBOT projects does not include any service work; therefore, leak prone services that are connected to large diameter cast iron mains, and which A) have already been addressed using CISBOT; B) are planned to be address using CISBOT; or C) will have to be addressed using CISBOT in the future as they are not suitable lining candidates, will be addressed under the proactive service replacement program (unless they are relayed sooner reactively). The presently maintained list of services to be replaced under the Proactive Service Replacement Program does not include such services; however, the Company is committed to addressing this as part of its service replacement program.

Prepared by or under the supervision of: Corey Hogg

Division 1-27

Request:

How many leak prone services under high pressure are connected to inside meter sets? Do these services pose a higher risk as opposed to high pressure connected to an outside meter set? What is the Company's plan to address these services?

Response:

Leak prone services running at high pressure with inside meter sets were considered the primary target of the Proactive Service Replacement program when originally initiated under the Accelerated Replacement Program (ARP) of 2008. At this time, the Company's records indicate they have all been addressed.

Prepared by or under the supervision of: Barry Foster

Division 1-27 (Revised)

Request:

How many leak prone services under high pressure are connected to inside meter sets? Do these services pose a higher risk as opposed to high pressure connected to an outside meter set? What is the Company's plan to address these services?

Original Response:

Leak prone services running at high pressure with inside meter sets were considered the primary target of the Proactive Service Replacement program when originally initiated under the Accelerated Replacement Program (ARP) of 2008. At this time, the Company's records indicate they have all been addressed.

Revised Response:

The Company is submitting this revised response because initially, the Company misinterpreted the question and responded in the context of the Proactive Service Replacement Program only. This revised response is in the context of the entire Rhode Island gas distribution system, which aligns with the question as submitted by the Division.

Per the Company's 2021 DIMP Plan submission, there were 908 high pressure bare steel services with inside meter sets. The Company's records indicate all of these are connected to mains that are within the scope of the Company's Leak Prone Pipe (LPP) / Main Replacement Program. Any isolated high pressure bare steel services with inside meter sets connected to mains outside of the LPP program have been replaced by the Company's Service Replacement Program ("SRP") when the program originally ran from FY 2013 through FY 2016. High pressure bare steel services with inside meter sets do pose a higher risk ranking score over outside sets. When leaks are encountered on any of these existing services, the risk score is included in the overall selection of the highest risk rank / prioritization of mains selected for replacement.

Division 1-28

Request:

Provide an updated list of all heaters on the Company's Rhode Island gas distribution system and their current status including ownership, age, risk rank and replacement schedule.

Response:

The table below shows the requested information. Replacement year is referring to calendar year:

Reg Stations ID	Supplier	Station Number	Risk Rank	Replacement Year		Ownership	Boiler Type	Age
				Heater	Glycol System			
East Providence (Wampanoag)	**AGT**	**RIS-004**	**1**	2022	2022	Enbridge (Transfer Pending)	Waterbath	35
Portsmouth	**AGT**	**RIS-N203**	**2**	2025	2025	RIE	Waterbath	22
East Providence (Dey St)	**AGT**	**RIS-311**	**3**	2023	2023	RIE	Waterbath	23
Cumberland (Scott Rd) - Heater 1 (2008)	**KM**	**RIN-C046**	**4**	2024	2024	RIE	Waterbath	13
Warren	**AGT**	**RIS-BW010**	**5**	2025	2025	Enbridge	Waterbath	18
Smithfield	**KM**	**RIS-125**	**6**	2022	2023	RIE	Hydronic	22
Westerly	**AGT**	**RIS-OBL**	**7**	2024	2024	Enbridge	Waterbath	28
Tiverton	**AGT**	**RIS-TIV1**	**8**	2022	2022	Enbridge (Transfer Pending)	Hydronic	28
Cumberland (Diamond Hill)	**AGT**	**RIN-C047**	**9**	2023	2024	RIE	Hydronic	31

Division 1-28, page 2

Reg Stations ID	Supplier	Station Number	Risk Rank	Replacement Year		Ownership	Boiler Type	Age
				Heater	Glycol System			
Portsmouth	**AGT**	**RIS-N203**	**10**	2025	2025	RIE	Waterbath	9
Providence (Manchester St TS)	**AGT**	**RIS-400**	**11**	2023	2024	RIE	Hydronic	15
Lincoln	**KM**	**RIN-C045**	**12**	2025	2025	RIE	Waterbath	8
Cumberland (Scott Rd) - Heater 2 (2015)	**KM**	**RIN-C046**	**13**	2023	2023	RIE	Waterbath	6
Smithfield	**KM**	**RIS-402**	**14**	2022	2023	RIE	Hydronic	4
Burrillville	**AGT**	**RIS-340**	**15**	2026	2026	RIE	Waterbath	7
Cranston	**KM**	**RIS-334**	**16**	NA	NA	RIE	Hydronic	1
Providence (Crary St TS)	**AGT**	**RIS-343**	**17**	NA	NA	RIE	Waterbath	3

Prepared by or under the supervision of: Justin Zaccari

Division 1-29

Request:

On Page 26, with respect to the Atwells Avenue Main Replacement, the Company's filing states that "[w]hen this 21-Month Plan budget was finalized . . . it included final restoration costs for DePasquale Square that were expected to carry into CY 2023; however that work has started earlier than expected; the Company plans to reduce the 21 Month Plan budget based on work completed during FY 2023." Please explain the following:

(a) How much were the budgeted restoration costs for DePasquale Square?

(b) Of the total amount of these costs, provide an estimate of the amount that is expected to "carry into CY 2023?" and what is the impact on the CY 2023 budget? Please explain.

Response:

The budgeted restoration costs for DePasquale Square were $0.40 million. The DePasquale Square final restoration work is now complete, except for line striping that is expected to be completed in Q3 FY2023. All final restoration work and resulting costs related to Segments 1A & 1B, which includes DePasquale Square, are expected to be completed by the end of FY 2023. Therefore, the full $0.40 million related to the DePasquale Square final restoration that was included in the 9-month CY 2023 budget for Atwells Avenue will be removed. The Atwells Avenue 9-month CY 2023 budget will be reduced from $1.50 million to $1.10 million and that remaining budget will be used to complete the final phase, Segment 3, of the project by the end of CY 2023.

Division 1-30

Request:

On Pages 26-27, the Company states that "[t]he start of Segment 3 of the project will likely be delayed from FY 2023 until the 21-Month Plan as the Company is continuing to work in close conjunction with Providence Water (replacing water pipe) and the City of Providence (replacing leak prone pipe ahead of municipal paving) to address the highest priority work":

(a) Are there words or a phrase missing from the above quote?

(b) Explain the delay associated with the Segment 3 work and how this delay impacts the CY 23 9-Month Budget and the CY 24 12-Month Budget.

Response:

(a) The Company will revise the quoted statement in the question as follows:: "the start of Segment 3 of the project will likely be delayed from FY 2023 until the 21-Month Plan as the Company continues to prioritize work in order of highest risk as well as in close conjunction with Providence Water projects and the City of Providence paving projects to ensure that leak prone pipe does not become subject to permit moratoriums and that ratepayer paving costs are minimized."

(b) The Company has prioritized higher risk work ahead of Segment 3, causing it to be delayed from the original schedule. The expected costs associated with Segment 3 total $1.1M, including restoration. These costs have been included in the 9-month CY 2023 portion of the 21-month plan proposal.

Prepared by or under the supervision of: Phil Lafond

Division 1-31

Request:

Regarding the Heater Installation program on Page 29, provide details including the total cost, and a construction timeline for the Dey Street, Diamond Hill and Smithfield Gate Station heater replacements.

Response:

Dey St: Installation of waterbath heater and inlet piping to replace the existing heater and inlet piping.

Pre-FY 2023 Actuals	$0.700M	Engineering, heater purchase
FY 2023	$0.317M	Engineering, heater acceptance testing, storage fees
9 Month CY 2023	$2.550M	Complete materials procurement, construction, and commissioning
CY 2024	$0.052M	Closeout and removal
Total	**$3.619M**	

Diamond Hill: Installation of hydronic heating system including two new 105 MBTU/h boilers, heat exchanger, new glycol piping and new 3" heat exchanger piping.

FY 2023 Forecast	$0.100M	Project development and long lead material procurement
9 Month CY 2023	$0.300M	Engineering and material procurement
CY 2024	$0.896M	Construction of new heating system, removal, and commissioning
Total	**$1.296M**	

Division 1-31, Page 2

Smithfield: Installation of hydronic heating system including two new 1.7 MMBTU/h boilers, heat exchanger, new glycol piping and new 8" heat exchanger piping.

FY 2023 Forecast	$0.450M	Boiler replacement and engineering
9 Month CY 2023	$1.950M	Material procurement, construction of new heating system, and commissioning
CY 2024	$0.040M	Closeout and removal
Total	**$2.440M**	

Division 1-32

Request:

Regarding Take Station Refurbishment, provide a detailed description of the Smithfield Gate Station project including the total cost, a site plan and a construction timeline. Also explain how this project differs with the heater replacement project at this same location as discussed in Div 1-31.

Response:

Smithfield Gate Station does not require full replacement of the Take Station since it is less than 25 years old and almost 80% of its records have been verified. A partial rebuild is required since its original 1999 design does not allow the installation of three layers of overpressure protection due to its stacked run configuration. The refurbishment project includes moving the 35 PSIG runs to a distribution vault downstream of the take station and installation of two new 99 PSIG runs inside of the building. This will eliminate the 1000 PSIG to 35 PSIG pressure cut, which mitigates the risk of a large over-pressurization of that system. This is separate from the heating system replacement project, in that the heating system replacement project involves separate equipment, heat exchanger piping and glycol piping, while this project involves regulation equipment and regulator piping.

Please see below for the project timeline, budget and site plan.

FY 2023	$0.150M	Engineering
9 Month CY 2023	$0.960M	Material procurement, and construction and gas in of new regulating vault downstream of take station
CY 2024	$2.400M	Material procurement and replacement of existing take station piping and regulators
Total	**$3.510M**	

Division 1-33

Request:

Provide an updated overall Risk Ranked list of all Pressure Regulating Facilities on the Rhode Island gas system including any abandonments and/or replacements over the past 5 years.

Response:

Stations are now risk-ranked on a variety of factors including pressure, age, configuration, condition, and customer requirements. Stations ranked 1-42 were considered "high risk" at the beginning of FY 2023 and now 39 remain. Stations ranked 43-102 are considered "medium-high" risk. Although the high-risk stations are prioritized in the work plan, individual stations with lower rankings may still need to be replaced or upgraded based on specific risks discovered in the field or if required as part of efficiently coordinating across departments.

The stations highlighted in green below were reconstructed in 2022.

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
EAST PROVIDENCE	RIS-004	Wampanoag Trail TS	Gate Station	1	Providence 200#	36
CUMBERLAND	RIN-C046	68 Scott Rd TS	Gate Station	2	Upper Cumberland 99#	52
PROVIDENCE	RIS-083	Pettis St @ N Main St	Reg Station	3	Providence LP	49/New
NORTH PROVIDENCE	RIS-110	Smith St @ Sunset Av	Reg Station	4	Providence LP	35
NORTH PROVIDENCE	RIS-082	Waterman @ Whitman St	Reg Station	5	Providence LP	45
PAWTUCKET	RIN-C022	Weeden St @ Smithfield Av	Reg Station	6	Pawtucket LP	43
PAWTUCKET	RIN-C021	337 Lonsdale Av	Reg Station	7	Pawtucket LP	45
LINCOLN	RIN-C018	Boulevard Av @ Front St	Reg Station	8	Pawtucket LP	43
CRANSTON	RIS-334	67 Laten Knight Road TS	Gate Station	9	Cranston 149#	19
PROVIDENCE	RIS-121	Broad St @ Early St	Reg Station	10	Providence LP	26

Division 1-33, page 2

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
PROVIDENCE	RIS-078	Ives St @ Trenton St	Reg Station	11	Providence LP	25
CRANSTON	RIS-113	Depot Av @ Cranston St	Reg Station	12	Providence LP	34
WARWICK	RIS-036	Post Rd @ Byron Blvd	Reg Station	13	Providence LP	31
CRANSTON	RIS-017	Station St @ Pond St	Reg Station	14	Providence LP	21
PROVIDENCE	RIS-065	Corina St @ Glasglow LP	Reg Station	15	Providence LP	26
CRANSTON	RIS-108	11 Lawnacre Dr @ Wayside Dr	Reg Station	16	Providence LP	20
PORTSMOUTH	RIS-N203	135 Old Mill Ln TS	Gate Station	17	Newport/Middleton 99#	22
PROVIDENCE	RIS-109	477 Dexter St	Reg Station	18	Providence LP	34
CUMBERLAND	RIN-C017	West Highland Av @ High St	Reg Station	19	Pawtucket LP	43
WARWICK	RIS-035	186 N Country Club Dr	Reg Station	20	Providence LP	22
CRANSTON	RIS-114	110 Atwood Av @ D St	Reg Station	21	Providence LP	19
CRANSTON	RIS-016	Park Av @ Hayward Av	Reg Station	22	Providence LP	27
LINCOLN	RIN-C045	600 George Washington Hwy (Rt 116) TS	Gate Station	23	Upper Cumberland 99#	29
CRANSTON	RIS-077	Fountain Av @ Dyer Av	Reg Station	24	Providence LP	29
PROVIDENCE	RIS-122	30 Virginia Av	Reg Station	25	Providence LP	25
PROVIDENCE	RIS-023	Westminster St @ Rt 10	Reg Station	26	Providence LP	27
PROVIDENCE	RIS-116	Silver Spring St @ Metcalf St	Reg Station	27	Providence LP	25

Prepared by or under the supervision of: Justin Zaccari

Division 1-33, page 3

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
CRANSTON	RIS-119	Wellington Av @ Well Av	Reg Station	28	Providence LP	16
JOHNSTON	RIS-034	Atwood Av @ 1401 Plainfield St	Reg Station	29	Johnston 35#	36
WEST WARWICK	RIS-133	Cowesett Av @ Quaker Ln	Reg Station	30	Rhode Island 99#	15/New
WARWICK	RIS-107	Warwick Av @ W Shore	Reg Station	31	West Shore 35#	37
SMITHFIELD	RIS-402	347 Putnam Pike TS (Rt 44) 99 PSIG	Gate Station	32	Rhode Island 99#	23
CRANSTON	RIS-096	Broad St @ Columbia Av	Reg Station	33	Providence LP	21
JOHNSTON	RIS-100	Allendale Av @ Geo. Waterman	Reg Station	34	North Providence/Johnston 35#	35
JOHNSTON	RIS-090	1827 Plainfield Pk @ Simmonsville	Reg Station	35	West Shore 35#	43/New
WEST WARWICK	RIS-104	E Greenwich St @ Quaker Ln	Reg Station	36	West Shore 35#	38
PAWTUCKET	RIN-C024	Senate St @ Daggett Av	Reg Station	37	Pawtucket LP	29
PAWTUCKET	RIN-C028	Oregon Av @ Manistee St	Reg Station	38	Pawtucket LP	29
CENTRAL FALLS	RIN-C020	550 High St	Reg Station	39	Pawtucket LP	20
LINCOLN	RIN-C048	New River Rd @ Cottage St	Reg Station	40	South Cumberland 60#	33
PAWTUCKET	RIN-C027	Bloomfield St @ Armistice Blvd	Reg Station	41	Pawtucket LP	25
NORTH PROVIDENCE	RIN-132	Waterman Av @ Greystone	Reg Station	42	Providence LP	15

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Division 1-33, page 4

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
CENTRAL FALLS	RIN-C019	Liberty St @ Hunt St	Reg Station	43	Pawtucket LP	19
EAST GREENWICH	RIS-068	337 Cowesett Rd	Reg Station	44	West Shore 35#	40
PAWTUCKET	RIN-C036	Dora St @ Vincent Av	Reg Station	45	Pawtucket LP	21
NEWPORT	RIS-N213-LP	Wellington St @ Thames St LP	Reg Station	46	Newport LP	12
EAST PROVIDENCE	RIS-089	Willet Av @ Forbes St 25 PSIG	Reg Station	47	East Shore 25#	32/New
EAST GREENWICH	RIS-069	816 Middle Rd	Reg Station	48	West Shore 35#	53/New
CRANSTON	RIS-049	1584 Plainfield St @ Plainfield Pk	Reg Station	49	Providence LP	11
SMITHFIELD	RIS-125	347 Putnam Pike TS (Rt 44) 35 PSIG	Gate Station	50	Johnston 35#	23
WOONSOCKET	RIN-C007	Kendrick Av @ Gaulin Av	Reg Station	51	Woonsocket LP	46
NORTH PROVIDENCE	RIS-129	David St @ Mineral Spring Av	Reg Station	52	Providence LP	12
PROVIDENCE	RIS-128	Allens Av @ Blackstone St	Reg Station	53	Providence LP	11
PAWTUCKET	RIN-C033	Kepler St @ Divison St	Reg Station	54	Pawtucket LP	23
PROVIDENCE	RIS-048	Hyacinth St @ Shiloh St	Reg Station	55	Providence LP	11
PAWTUCKET	RIN-C032	Bacon St @ Columbus Av	Reg Station	56	Pawtucket LP	25
PAWTUCKET	RIN-C026	Downes Av @ Robinson Av	Reg Station	57	Pawtucket LP	22

Division 1-33, page 5

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
CENTRAL FALLS	RIN-C050	Broad St @ Hunt St	Reg Station	58	Pawtucket LP	11
WOONSOCKET	RIN-C005	Bailey St @ Ballou St	Reg Station	59	Woonsocket LP	36
NORTH PROVIDENCE	RIS-088	Corina St @ Glasgow 35 PSIG	Reg Station	60	North Providence/Johnston 35#	12
PROVIDENCE	RIS-024.1	Hartford Av @ Petteys Av (Holder 19) LP	Reg Station	61	Providence LP	12
PROVIDENCE	RIS-024.3	Hartford Av @ Petteys Av (Holder 19) 18" Line	Reg Station	62	Providence 10#	20
PROVIDENCE	RIS-024.5	Hartford Av @ Petteys Av (Holder 19) Dey St Line	Reg Station	63	Providence 10#	20
PAWTUCKET	RIN-C030	North Bend St @ Cottage St	Reg Station	64	Pawtucket LP	23
EAST PROVIDENCE	RIS-315	Wampanoag Trail @ Tripps Ln	Reg Station	65	East Shore 99#	13
WESTERLY	RIS-OOB-R	Westerly TS (Relief Only)	Gate Station	66	Westerly 75#	20
JOHNSTON	RIS-029	20 Serrel Sweet Rd	Reg Station	67	Providence LP	10
CUMBERLAND	RIN-C049	Mendon Rd @ Nate Whipple Hwy	Reg Station	68	South Cumberland 60#	32
PROVIDENCE	RIS-103	Promenade St @ Kingsley Av (121 Providence Place)	Reg Station	69	Providence LP	38
NORTH PROVIDENCE	RIS-026	Eliot Av @ Barrett Av	Reg Station	70	Providence LP	9

Prepared by or under the supervision of: Justin Zaccari

Division 1-33, page 6

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
PAWTUCKET	RIN-C023	Moshassuck St @ Main St	Reg Station	71	Pawtucket LP	14
JOHNSTON	RIS-063	Hartford Av @ Dale Av	Reg Station	72	Providence LP	9
WEST WARWICK	RIS-120	Providence St @ Toll Gate Rd	Reg Station	73	West Shore 35#	26
WARREN	RIS-BW010	Warren TS	Gate Station	74	Bristol Warren 60#	10
PROVIDENCE	RIS-098	Chalkstone St @ Rosebank Av	Reg Station	75	Providence LP	8
EAST PROVIDENCE	RIS-071	Willet Av @ Forbes St 5 PSIG	Reg Station	76	East Providence 5#	41/New
WOONSOCKET	RIN-C006	Kenwood St @ Cass Av	Reg Station	77	Woonsocket LP	30
CRANSTON	RIS-073	Mayfield Rd @ Oakland Av	Reg Station	78	West Shore 35#	29
CRANSTON	RIS-018	Park Av @ Maple Av	Reg Station	79	Providence LP	12
PROVIDENCE	RIS-022	Niantic Av @ Pawnee St	Reg Station	80	Providence LP	12
EAST PROVIDENCE	RIS-015	Pawtucket Av @ Waterman Av	Reg Station	81	East Providence LP	12
PAWTUCKET	RIN-C031	Tidewater St @ Taft St City Reg	Reg Station	82	Pawtucket LP	11
NORTH KINGSTOWN	RIS-118	3362 Kingstown Rd (Waites Corner)	Reg Station	83	West Shore 35#	29
PROVIDENCE	RIS-094	Dyer St @ Pine St	Reg Station	84	Providence 35#	18
PROVIDENCE	RIS-008	Brook St @ George St LP	Reg Station	85	Providence LP	7
NEWPORT	RIS-N220	Memorial Blvd @ Anna Dr	Reg Station	86	Newport 10#	25

Prepared by or under the supervision of: Justin Zaccari

Division 1-33, page 7

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
EAST PROVIDENCE	RIS-046	Centre St @ Castro St	Reg Station	87	East Providence LP	22
NORTH KINGSTOWN	RIS-081	Ten Rod Rd (Pole 110)	Reg Station	88	West Shore 35#	31
EAST PROVIDENCE	RIS-006	Pawtucket Av @ Sprague St	Reg Station	89	Riverside LP	28
LINCOLN	RIN-C037	Woodland St @ Smithfield Av	Reg Station	90	Pawtucket LP	10
MIDDLETOWN	RIS-N209	Walcott Av @ St Georges	Reg Station	91	Middleton LP	15
COVENTRY	RIS-126	433 Hopkins Hill Rd	Reg Station	92	West Shore 35#	22
NORTH PROVIDENCE	RIS-027	Smithfield Rd @ Cushing St	Reg Station	93	Providence LP	9
WOONSOCKET	RIN-C004	Harris Av @ Blackstone St	Reg Station	94	Woonsocket LP	18
PAWTUCKET	RIN-C025	290 Daggett Av	Reg Station	95	Pawtucket LP	12
WOONSOCKET	RIN-C003	High St @ Fountain St	Reg Station	96	Woonsocket LP	18
EAST PROVIDENCE	RIS-130	Village Green N @ Pawtucket Av	Reg Station	97	East Providence 5#	16
EAST PROVIDENCE	RIS-123	Fort St @ S Broadway	Reg Station	98	East Providence LP	24
NEWPORT	RIS-N213-HP	Wellington St @ Thames St 40 PSIG	Reg Station	99	Newport 35#	12
TIVERTON	RIS-TIV1	401 Main Rd TS (Relief Only)	Gate Station	100	Tiverton 55#	20
EAST PROVIDENCE	RIS-117	County Rd @ Old County Rd	Reg Station	101	East Shore 25#	11
PAWTUCKET	RIN-C029	Maryland Av @ School St	Reg Station	102	Pawtucket LP	12

Prepared by or under the supervision of: Justin Zaccari

Division 1-33, page 8

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
WARWICK	RIS-038	East Av @ 650 Bald Hill Rd	Reg Station	103	Warwick/Bald Hill 25#	6
JOHNSTON	RIS-092	Traver Av @ Killingly St	Reg Station	104	Providence LP	4
WOONSOCKET	RIN-C012	Bourdon Blvd @ Asylum St	Reg Station	105	Woonsocket Int. 8#	29
JOHNSTON	RIS-057	915 Atwood Av @ Plainfield St (St Rocco's)	Reg Station	106	Providence LP	7
BRISTOL	RIS-BW005	213 Mt Hope Av	Reg Station	107	Bristol LP	37
EAST PROVIDENCE	RIS-014	N Broadway @ Greenwood St	Reg Station	108	East Providence LP	59
CUMBERLAND	RIN-C016	Ann & Hope Way	Reg Station	109	Pawtucket LP	8
NEWPORT	RIS-N216	Bliss Rd @ Broadway	Reg Station	110	Newport LP	11
PAWTUCKET	RIN-C051	Bernon St @ Front St	Reg Station	111	Woonsocket LP	13
WESTERLY	RIS-OOF	14A Perkins Av	Reg Station	112	Westerly LP	31
WARREN	RIS-BW014	Market St @ Kickemuit Rd	Reg Station	113	Warren LP	10
PROVIDENCE	RIS-091	Adelaide Ave @ Hamilton St	Reg Station	114	Providence LP	7
EAST PROVIDENCE	RIS-099	860 Waterman Av	Reg Station	115	S. East Providence 35#	33
CUMBERLAND	RIN-C044	1595 Mendon Rd	Reg Station	116	South Cumberland 60#	9
PROVIDENCE	RIS-115	Doyle Av @ Tabor Av	Reg Station	117	Providence LP	18
PORTSMOUTH	RIS-N204	135 Old Mill Ln	Reg Station	118	Portsmouth 55#	8
WARREN	RIS-310	28 Brown St TS (Barrington Bldg)	Gate Station	119	East Shore 25#	10

Division 1-33, page 9

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
PROVIDENCE	RIS-087	Silver Spring St @ Charles St	Reg Station	120	Providence LP	4
NORTH PROVIDENCE	RIN-C038	Charles St @ Mineral Spring Av	Reg Station	121	Pawtucket LP	7
PAWTUCKET	RIN-C035	Tidewater St @ Taft St B Run	Reg Station	122	Pawtucket Intermediate 18#	11
WOONSOCKET	RIN-C002	Rockland Av @ Morse Av	Reg Station	123	Woonsocket LP	11
WESTERLY	RIS-OOC	53 Ward Av	Reg Station	124	Westerly LP	18
MIDDLETOWN	RIS-N221	Maple Av @ Yarnell Av	Reg Station	125	Newport 10#	12
WOONSOCKET	RIN-C009	Asylum St @ Mason St	Reg Station	126	Woonsocket LP	12
JOHNSTON	RIS-124	Scenery Ln	Reg Station	127	Johnston Scenery Ln. 35#	23
BRISTOL	RIS-BW015	8 Gooding Av	Reg Station	128	Bristol Warren 8#	12
EAST PROVIDENCE	RIS-047	747 Bullocks Point Av	Reg Station	129	Riverside LP	16
PAWTUCKET	RIN-C042	Smithfield Av @ Weeden St	Reg Station	130	South Cumberland 60#	14
EAST PROVIDENCE	RIS-311	27 Dey St TS	Gate Station	131	Rhode Island 99#	6
LINCOLN	RIN-C043	Cobble Hill Rd @ Louisquisset Pk	Reg Station	132	South Cumberland 60#	11
MIDDLETOWN	RIS-N212	W Main Rd @ Dudley Av	Reg Station	133	Newport LP	10
MIDDLETOWN	RIS-N202	W Main Rd @ Oliphant Ln	Reg Station	134	Newport 10#	12
NEWPORT	RIS-N219	Carroll Av @ Ocean Dr	Reg Station	135	Newport LP	12
WEST WARWICK	RIS-134	565 Quaker Ln	Reg Station	136	Greenwich 35#	12

Division 1-33, page 10

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
EAST PROVIDENCE	RIS-131	Amaral St @ Wampanoag Trail	Reg Station	137	S. East Providence 35#	16
LINCOLN	RIN-C014	Railroad Av @ Winter St LP	Reg Station	138	Lincoln/Manville LP	8
PROVIDENCE	RIS-079	Ship St @ Chestnut St	Reg Station	139	Providence 35#	9
PROVIDENCE	RIS-400	30 Allens Av (Manchester St) TS Power Plant	Gate Station	140	VPEM 350#	19
WESTERLY	RIS-OOA	10 White Rock Rd	Reg Station	141	Westerly 21#	10
MIDDLETOWN	RIS-N205	305 Corey Ln	Reg Station	142	Corey Lane 25#	11
WESTERLY	RIS-OOG	Friendship St - Yankee Line	Reg Station	143	Westerly 60#	8
CRANSTON	RIS-020	Cannon St	Reg Station	144	Cannon St. 35#	11
EAST PROVIDENCE	RIS-001	500 Veterans Mem Pkwy (Bentley St)	Reg Station	145	East Providence 25#	5
WESTERLY	RIS-OBL	12 Canal St	Reg Station	147	Westerly LP	8
PROVIDENCE	RIS-105	Brook St @ George St 35 PSIG	Reg Station	148	South Providence 35#	7
PROVIDENCE	RIS-127	Point St @ Beacon Av	Reg Station	149	Providence LP	21
WOONSOCKET	RIN-C001	St James Way @ Mendon Rd	Reg Station	150	Woonsocket LP	8
WESTERLY	RIS-OOE	Beach St @ 11 Watch Hill Rd	Reg Station	151	Westerly LP	10
EAST PROVIDENCE	RIS-003	First St @ Mauran Av (Holder 20) LP	Reg Station	152	East Providence LP	10

Division 1-33, page 11

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
WESTERLY	RIS-OOD	54 East Av	Reg Station	153	Westerly LP	8
WOONSOCKET	RIN-C010	E School St @ Pond St	Reg Station	154	Woonsocket LP	7
MIDDLETOWN	RIS-N201	Newman Rd @ Aquidneck Av	Reg Station	155	Newport 10#	12
NEWPORT	RIS-N217	Boulevard St @ Miantonomi	Reg Station	156	Newport 10#	12
PAWTUCKET	RIN-C039	Tidewater St @ Taft St Primaries	Reg Station	157	South Cumberland 60#	11
TIVERTON	RIS-TIV2	Evans Av @ Pierce Av	Reg Station	158	Tiverton 5#	8
EAST PROVIDENCE	RIS-002	First St @ Mauran Av (Holder 20) 5 PSIG	Reg Station	159	East Providence 5#	10
PROVIDENCE	RIS-111	Canal St @ Washington St	Reg Station	160	Providence LP	12
NORTH KINGSTOWN	RIS-084	Stony Ln @ Rt 2	Reg Station	161	N. Kingston Stony Ln. 35#	10
NORTH KINGSTOWN	RIS-097	6 Long Av	Reg Station	162	West Shore 35#	11
WARREN	RIS-309	22 Brown St Basement 25 PSIG	Reg Station	163	East Shore 25#	10
EAST PROVIDENCE	RIS-013	Summit St @ Taunton Av	Reg Station	164	East Providence LP	8
MIDDLETOWN	RIS-N215	E Main Rd @ Turner Rd	Reg Station	165	Newport 10#	12
WESTERLY	RIS-OBH	Friendship St - Spectra Line	Reg Station	166	Westerley 60#	8
EAST PROVIDENCE	RIS-064	Wampanoag Trail @ Boyd Av 5 PSIG	Reg Station	167	East Providence 5#	12

Division 1-33, page 12

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
BURRILLVILLE	RIS-340	1084 Wallum Lake Rd TS	Gate Station	168	Burrilville 35#	8
PAWTUCKET	RIN-C040	Sanford St @ Myrtle St	Reg Station	169	Pawtucket Intermediate 18#	3
BRISTOL	RIS-BW001	Franklin @ Wood 8 PSIG	Reg Station	170	Bristol Warren 8#	11
WARREN	RIS-BW013	22 Brown St Basement 8 PSIG	Reg Station	171	Bristol Warren 8#	12
EAST PROVIDENCE	RIS-056	Roger Williams Av @ Puritan	Reg Station	172	East Providence LP	4
BRISTOL	RIS-BW002	Wood St @ Shaws Ln LP	Reg Station	146	Bristol LP	9
EAST PROVIDENCE	RIS-067	Roger Williams Av @ Whitaker	Reg Station	173	East Providence 35#	4
EAST GREENWICH	RIS-093	Division Rd @ Quaker Ln	Reg Station	174	West Shore 35#	9
PROVIDENCE	RIS-320	Allens Av/LNG Fuel	Reg Station	176	LNG Fuel 70#	12
JOHNSTON	RIS-102	Greenville @ George Waterman	Reg Station	177	Johnston 35#	3
NEWPORT	RIS-N211	Americas Cup @ Poplar	Reg Station	178	Newport LP	2
PROVIDENCE	RIS-086	Fountain St @ Eddy St	Reg Station	179	Providence LP	2
BRISTOL	RIS-BW007	Woodlawn Av @ Wood St	Reg Station	175	Bristol LP	3
CRANSTON	RIS-032	Park Av @ Old Park Av	Reg Station	180	Cranston Providence 7#	1
JOHNSTON	RIS-101	1 Cottage St	Reg Station	181	Johnston 35#	1
EAST GREENWICH	RIS-106	Frenchtown Rd @ S County Trail	Reg Station	182	N. Kingstown Frenchtown Rd. 35#	1

Division 1-33, page 13

Town	Station Number	Station Name	Station Type	Risk Rank	System	Station Age
CUMBERLAND	RIN-C047	4425 Diamond Hill Rd TS	Gate Station	183	South Cumberland 60#	5
PROVIDENCE	RIS-306	Allens Av/19 Holder Filling Line New Reg Vault	Reg Station	184	Providence 10#	1
PROVIDENCE	RIS-308	Allens Av/Providence 7 PSIG New Station	Reg Station	185	Cranston Providence 7#	1
WARWICK	RIS-061	Maple St @ Albany	Reg Station	186	West Shore 35#	1
PROVIDENCE	RIS-343	30 Allens Av (Crary St) TS 99 PSIG	Gate Station	187	Rhode Island 99#	5
PROVIDENCE	RIS-300	Allens Av/Becker Cabinet 18" Line New 200 to 99 Building	Reg Station	188	Rhode Island 99#	1
PROVIDENCE	RIS-305	Allens Av/Hut New Station	Reg Station	189	West Shore 35#	1

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Division 1-33, page 14

Replacements and Abandonments: The table below represents stations that have been replaced or abandoned in the last 5 years. The stations highlighted in grey were stations that were abandoned.

Town	Station Number	Station Name	Work Type	System	Year
EAST PROVIDENCE	RIS-001	500 Veterans Mem Pkwy (Bentley St)	Replacement	East Providence 25#	2017
CUMBERLAND	RIN-C047	4425 Diamond Hill Rd TS	Replacement	South Cumberland 60#	2017
PROVIDENCE	RIS-343	30 Allens Av (Crary St) TS 99 PSIG	Replacement	Rhode Island 99#	2017
JOHNSTON	RIS-092	Traver Av @ Killingly St	Replacement	Providence LP	2018
PROVIDENCE	RIS-087	Silver Spring St @ Charles St	Replacement	Providence LP	2018
EAST PROVIDENCE	RIS-056	Roger Williams Av @ Puritan	Replacement	East Providence LP	2018
EAST PROVIDENCE	RIS-067	Roger Williams Av @ Whitaker	Replacement	East Providence 35#	2018
PAWTUCKET	RIN-C040	Sanford St @ Myrtle St	Replacement	Pawtucket Intermediate 18#	2019
JOHNSTON	RIS-102	Greenville @ George Waterman	Replacement	Johnston 35#	2019
BRISTOL	RIS-BW007	Woodlawn Av @ Wood St	Replacement	Bristol LP	2019
NEWPORT	RIS-N211	Americas Cup @ Poplar	Replacement	Newport LP	2020
PROVIDENCE	RIS-086	Fountain St @ Eddy St	Replacement	Providence LP	2020
CRANSTON	RIS-032	Park Av @ Old Park Av	Replacement	Cranston Providence 7#	2021
JOHNSTON	RIS-101	1 Cottage St	Replacement	Johnston 35#	2021
EAST GREENWICH	RIS-106	Frenchtown Rd @ S County Trail	Replacement	N. Kingstown Frenchtown Rd. 35#	2021
PROVIDENCE	RIS-306	Allens Av/19 Holder Filling Line New Reg Vault	Replacement	Providence 10#	2021

Division 1-33, page 15

Town	Station Number	Station Name	Work Type	System	Year
PROVIDENCE	RIS-308	Allens Av/Providence 7 PSIG New Station	Replacement	Cranston Providence 7#	2021
WARWICK	RIS-061	Maple St @ Albany	Replacement	West Shore 35#	2021
PROVIDENCE	RIS-300	Allens Av/Becker Cabinet 18" Line New 200 to 99 Building	Replacement	Rhode Island 99#	2021
PROVIDENCE	RIS-305	Allens Av/Hut New Station	Replacement	West Shore 35#	2021
PROVIDENCE	RIS-083	Pettis St @ N Main St	Replacement	Providence LP	2022
WEST WARWICK	RIS-133	Cowesett Av @ Quaker Ln	Replacement	Rhode Island 99#	2022
JOHNSTON	RIS-090	1827 Plainfield Pk @ Simmonsville	Replacement	West Shore 35#	2022
EAST PROVIDENCE	RIS-089	Willet Av @ Forbes St 25 PSIG	Replacement	East Shore 25#	2022
EAST GREENWICH	RIS-069	816 Middle Rd	Replacement	West Shore 35#	2022
EAST PROVIDENCE	RIS-071	Willet Av @ Forbes St 5 PSIG	Replacement	East Providence 5 #	2022
PROVIDENCE	RIS-274	Allens Av/Becker Cabinet Dey St	Abandonment	Rhode Island 99#	2022
PROVIDENCE	RIS-327	Allens Av/Hoxie	Abandonment	Rhode Island 99#	2022
EAST PROVIDENCE	RIS-005	Martin St @ Dodge St	Abandonment	East Providence LP	2022
PROVIDENCE	RIS-307	Allens Av/200 PSI Standby Run	Abandonment	Rhode Island 99#	2022
EAST PROVIDENCE	RIS-045	Harris@Hoppin	Abandonment	Riverside LP	2021
BRISTOL	RIS-BW006	Hope @ Silver Creek	Abandonment	Bristol LP	2020
WARWICK	RIS-037	122 Pettaconsett Av	Abandonment	Providence LP	2020
LINCOLN	RIN-C015	Quinn Ln @ Lower River Rd	Abandonment	Pawtucket LP	2018
Providence		Ontario @ Niagara	Abandonment	Providence LP	2018

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Division 1-33, page 16

Town	Station Number	Station Name	Work Type	System	Year
Providence	RIS-BWOO3	Oxford @ Burnside	Abandonment	Providence LP	2018
Providence	RIS-020	Westminster @ Dyer	Abandonment	Providence LP	2018
Cranston	RIS-040	Pontiac Ave	Abandonment	Providence LP	2018

Division 1-34

Request:

Regarding Pressure Regulating Facilities proposed upgrades on Page 31, provide a list of the 5-7 stations scheduled for CY 2023 and a list of the 6-8 stations scheduled for CY 2024 including the total costs, a description of work and location. Also list all stations in which a second bypass valve is proposed to be installed.

Response:

The chart below contains the locations of the proposed work under pressure regulating facilities as well as station details and information that influenced each work proposal. The scope of all station replacements is to install the following: a dual-run prefabricated regulator station with three layers of overpressure protection on each run; protective bollards; vents; and a traffic box containing system automation equipment. It is preferred to install the new station in the same location as the old station unless a new location is safer or more strategic. The scope of all station abandonments is to completely isolate, depressurize, cut, cap, and retire in place. Note that 347 Putnam Pike is a separate program and is part of take station modification project.

Station Name	Town	Project Type	9 Month CY2023 Cost	9 Month Activity	12 Month CY2024 Cost	12 Month Activity
Park Av @ Maple Av	CRANSTON	Replace Station	$0.45M	Construct		
Station St @ Pond St	CRANSTON	Replace Station	$0.65M	Construct		
Smith St @ Sunset Av	NORTH PROVIDENCE	Replace Station	$0.85M	Fabricate and Construct		
Weeden St @ Smithfield Av	PAWTUCKET	Replace Station	$0.85M	Fabricate and Construct		
337 Lonsdale Av	PAWTUCKET	Replace Station	$0.85M	Fabricate and Construct		
Mendon Rd @ Nate Whipple Hwy #1	CUMBERLAND	Replace Station	$0.85M	Fabricate and Construct		
Wellington St @ Thames St LP	NEWPORT	Replace Station	$0.35M	Procure Materials and Fabricate Vault	$0.90M	Construct
New River Rd @ Cottage St	LINCOLN	Replace Station	$0.375M	Procure Materials and Fabricate Vault	$0.90M	Construct

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Division 1-34, page 2

Station Name	Town	Project Type	9 Month CY2023 Cost	9 Month Activity	12 Month CY2024 Cost	12 Month Activity
Mendon Rd @ Nate Whipple Hwy #2	CUMBERLAND	Replace Station	$0.35M	Procure Materials and Fabricate Vault	$0.85M	Construct
110 Atwood Av @ D St	CRANSTON	Replace Station	$0.35M	Procure Materials and Fabricate Vault	$0.65M	Construct
235 Promenade St @ Kingsley Av	PROVIDENCE	Abandon Station	$0.045M	Engineer	$0.05M	Abandon
Walcott Av @ St Georges	MIDDLETOWN	Abandon Station	$-		$0.095M	Abandon
1584 Plainfield St @ Plainfield Pk	CRANSTON	Replace Station	$0.125M	Engineer and Procure Materials	$0.95M	Fabricate Vault and Construct
Wellington St @ Thames St 40 PSIG	NEWPORT	Replace Station	$0.125M	Engineer and Procure Materials	$1.20M	Fabricate Vault and Construct
TBD Station #1	TBD	Replace Station			$0.385M	Engineer, Procure Materials, and Fabricate
TBD Station #2	TBD	Replace Station			$0.385M	Engineer, Procure Materials, and Fabricate
TBD Station #3	TBD	Replace Station			$0.385M	Engineer, Procure Materials, and Fabricate
TBD Station #4	TBD	Replace Station			$0.385M	Engineer, Procure Materials, and Fabricate
TBD Station #5	TBD	Replace Station			$0.385M	Engineer, Procure Materials, and Fabricate
TBD Station #6	TBD	Replace Station			$0.20M	Engineer, Procure Materials
TBD Station #7	TBD	Replace Station			$0.20M	Engineer, Procure Materials
TBD Station #8	TBD	Replace Station			$0.20M	Engineer, Procure Materials
3362 Kingstown Rd (Waites Corner)	NORTH KINGSTOWN	Install Bypass Valve	$0.05M	Construct		

Division 1-34, page 3

Station Name	Town	Project Type	9 Month CY2023 Cost	9 Month Activity	12 Month CY2024 Cost	12 Month Activity
Mayfield Rd @ Oakland Av	CRANSTON	Install Bypass Valve	$0.05M	Construct		
Dyer St @ Pine St	PROVIDENCE	Install Bypass Valve			$0.10M	Procure Materials and Construct
Stony Ln @ Rt 2	NORTH KINGSTOWN	Install Bypass Valve			$0.10M	Procure Materials and Construct
259 Wamp Tr @ Boyd Av	EAST PROVIDENCE	Install Bypass Valve	$0.025M	Engineer	$0.125M	Procure Materials and Construct

Division 1-35

Request:

Regarding Gas System Reliability on Page 33, list all projects associated with the installation of 3.5 miles of new gas main designed to eliminate single feed systems. Include a description, the total costs and the site plans for each project.

Response:

Gas Planning & Operations Engineering has proposed a total of eight reliability projects for the 21-month budget for the upcoming 2023-2024 construction seasons. Four of the projects are to replace and integrate current single feed systems. The other four projects will be abandoning and upgrading existing low pressure gas mains with new high pressure plastic gas mains in coordination with other leak prone pipe integrity projects. The scope for all eight projects for CY 2023 and CY 2024 for the FY 2024 Gas ISR Plan (21-month budget) will be a total installation of 3 miles of main and will cost an estimated $4.75 million dollars.

Attachment Division 1-35 provides descriptions of each project, estimates, install lengths, and reasons why the project is being put in the FY 2024 Gas ISR Plan. Slides 2-9 of Attachment Division 1-35 include site plans showing the proposed scopes of work.

The site plan contains confidential critical energy infrastructure information. The Company is providing this information to the Division pursuant to the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022.

Some projects are still being designed but will be ready for construction and put into the work plan.

The site plan contains confidential critical energy infrastructure information
nd is being provided to the Division via a separate link.

RIEnergy Gas Planning & Operations Reliability – DIV1-35

Need-By Date	Town	Cost Estimate 2023 – 2024	WO	Project Type	Project Title	Project Description	Install Length (t)	Reason for Project
Customer need ASAP; Coordinate with MSR WO# 90000175676	Providence	$.15m	90000228513	LP Elimination	PVD 163-200 Sunbury St (LP-to-35)	Install aprx 420 ft of 2-in 35-psig PL in Sunbury St from #163 to #200 Sunbury St. Include 2" stubs in River Rd. Coordinate with MSR WO# 90000175676. Expedite for sales customer at #163 Sunbury St (This is not growth related project, just a customer benefit)	400	LP Elimination
Coordinate with MSR WO# 90000219059	Lincoln	$.7m	90000209541	Single-Feed Elimination	LNC Old River Rd, Manville (LP-99)	Relay 1700 ft of LP main (Plastic, Wrapped Steel, Bare Steel, 50ft Cast Iron) with 8-inch 99 psig Plastic in Old River Rd LNC (RIDOT) from the existing 6 inch, 99 psig plastic (2017) at #315 Old River Rd to Manville Av (MRI2003241 90000204640). Relay 250 ft of 2 inch, LP bare steel, with aprx 250 feet of 2 inch, 99 psig plastic in Desoto Wy from Old River Rd to the end of main at #4 Desoto Wy. Convert all services from LP to 99 psig. Coordinate with MSR WO# 90000219059. [RIDOT paved Old River Rd in 2017.]	2000	Part of LP-single-feed elimination in Lincoln/Manville. Creates new feed for 99# system improving reliability and pressures to RIN-C048.
With or after MSR WO# 90000211503	Lincoln	$1.0m	90000231856	LP Elimination	LNC Beverly Dr (LP-99)	Replace aprx 650 ft of 4-in/6-in LP CI with 600 ft of 4-in 99-psig PL in River Rd from the new 99-psig main at Arnold St to the existing 99-psig main in Front St. Replace the following with aprx 4000 ft of 2-in 99-psig PL: 535 ft of 4-in LP DI in Bradford Dr from River Rd to the new 99-psig main at Allan Dr, 570 ft of 4-in LP CS and 130 ft of 4-in LP PL in Allan Dr from Bradford Dr to Bernon Dr, 1345 ft of 6-in LP PL in Bernon Dr from Allan Dr to end of main, 370 ft of 4-in LP PL in Pace Ct, 695 ft of 8-in LP CS, 50 ft of 6-in/8-in LP BS, and 305 ft of 6-in/8-in LP PL in Beverly Dr from Bernon Dr to the new 99-psig main at River Rd. Convert all services in scope to 99-psig. Coordinate with MSR WO# 90000211503.	4600	LP system elimination. Improves reliability by looping this section of the 99# system.
Needed for MSR WO# 90000225941	North Providence	$.2m	90000231076	LP Elimination	NPV 1-26 Borah St (LP-to-60)	Replace aprx 600 ft of 6-in LP PL/CI with aprx 600 ft of 2-in 60-psig plastic in Borah St from Charles St to Florence St. Convert LP services within scope to 60-psig. This project is needed for MSR WO# 90000225941.	600	LP Elimination.
Needed for MSR WO# 90000226113	Woonsocket	$.3m	90000231075	LP Elimination	WSO Diamond Hill Rd-Dewey St (60)	Install aprx 730 ft of 8-in 60-psig plastic in Diamond Hill Rd from Dewey St to the existing 60-psig main in Saint Leon Ave. Convert LP services within scope to 60-psig. DO NOT ABANDON LP MAIN. This project is needed for MSR WO# 90000226113.	700	LP Elimination. Load shed improves LP pressures.
CY24	Newport	$.6m	90000218149	System Integration	NPR (10-to-35) P1-3	Phase 1: Replace 1700 ft of 10-psig main with 2800 ft of 4-in 35-psig plastic in Beacon Hill Rd and Harrison Av NPR. Convert services to 35-psig.Phase 2: Replace 4300 ft of 10-psig main with 3930 ft of 4-in 35-psig plastic in Harrison Av from Beacon Hill Rd to Halidon Av. Convert services to 35-psig.Phase 3: Relay all 10# main from Halidon Av to Thames St with 2-in 35# PL. Convert services to 35-psig.	1700	Reduce Newport 10# (single-feed south of RIS-N220) and integrate with / loop Newport 35# system
CY24	Warwick	$.75m	90000220806	Single-Feed Elimination	WWK East Av/Bald Hill Rd SFE	Replace aprx 3580 ft of 30/35-psig main with 2-in 99-psig plastic off Bald HIll Rd/East Av, WWK. Convert services to 99-psig. Retire three single-feed regulators.Farm Tap East Ave 30#: aprx 2610 ft of 2/3/4-in 30-psig PE/CS. Farm Tap East Ave N: aprx 340 ft of 2-in 35-psig PB/CS. Farm Tap East Ave S: aprx 630 ft of 2-in 35-psig PE/CS.	3600	Eliminate three single-feed 30/35-psig regulators off Bald Hill Rd, Warwick. Integrate with larger 99-psig system via main replacement to improve reliability and reduce O&M.
CY24	Cranston	$.7m	90000220913	Single Feed Elimination	Cannon St CRA	As part of the GPLNG program, Strategic Asset and System Planning recommends:-Install approx. 2,610ft of 2-in 99# PE main and abandon approx. 50ft of 2-in 35# CS (MCRA0025) main and 2,560ft of 2-in 35# PE main at the 200 Cannon St CRA neighborhood off Walnut Grove Av. Services to the proposed 99# PE main shall be replaced. Retire single-feed station RIS-020.- Total main installation: 2,610ft- Total main abandonment: 2,610ft Services:39 Main Connections/Cutoffs: 1 Work Scheduled to retire single feed station RIS-020	2600	Eliminate single feed regulator station & single feed 35# system.
		$4.75m					16,200 ft (3 miles)	

The site plan contains confidential critical
energy infrastructure information
and is being provided to the Division via a separate link.

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Division 1-36

Request:

Regarding Distribution Station Over-Pressure Protection on Page 34, provide a list of all regulator stations in which the Company proposes to install outlet control lines in CY 2023.

Response:

Subject to coordination of the work with the Company's main replacement program, the Company anticipates that it will install control line headers at three to five of the locations listed below in CY 2023:

Station Number	Station Name	Town
RIS-014	North Broadway @ Greenwood Ave	East Providence
RIS-N221	Maple @ Yarnell Ave	Middletown
RIS-119	Wellington Ave @ Well Ave	Cranston
RIS-113	Depot Av @ Cranston St	Cranston
RIN-C009	Mason St @ Asylum St	Woonsocket
RIN-C023	Moshassuck St @ Main St	Pawtucket

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Division 1-37

Request:

Regarding the Exeter LNG Facility, list all upgrades to the facility in the past three years including the current status and all costs spent to date.

Response:

Major upgrades to the Exeter LNG Facility in the past three years include the following:

- FY 2021 Installed 30' x 40' storage building to house critical spares, plant machinery, and general stock materials for the site. Total cost, $0.59 million.

- FY 2023 Commissioned Hi-Ex Foam System at the LNG Truck Unloading Area and LNG Pump our area. Cost to date is $4.96 million, with total projected cost estimated at $5.30 million.

- FY 2023 Completed engineering design and started procurement process for two additional BOG Compressors to replace the plant's original BOG Compressors. Construction is scheduled to commence in FY 2024 and completion is expected in FY 2025. Total engineering cost and procurement for this phase was $2.93 million.

Division 1-38

Request:

Explain in detail each proposed upgrade for the Exeter LNG Facility including the total costs for each upgrade, a project description, a construction timeline and provide a site plan for the facility depicting all current and proposed upgrades, and further provide:

(a) Documentation that supports the $3.33 M budget for the switchback stairs;

(b) Documentation that supports the $9.17 M to move the control room;

(c) Documentation that supports the $10.40 M for the LNG truck station;

(d) Documentation that support the $15.00 M for the two boil-off compressors; and

(e) Provide the National Grid Study regarding the facilities in (a)-(d) mentioned during the Walk-through.

Response:

Please see Attachment Division 1-38-1 for a copy of the site plan showing the current Exeter LNG Facility and the proposed upgrades listed in subparts (a) through (d), above. The Company is in the process of issuing requests for proposals ("RFP") for the proposed upgrades, as discussed below; therefore, detailed cost estimates and construction timelines have not been developed yet. In addition, the Company provides the following detail:

(a) Switchback Stairs

The switchback stair project adds a modern and safer stair system to access the top area of the LNG tank. Switchback systems include platforms at each transition level to permit personnel to pass one another or take a break from the ascent/descent. The design will incorporate:

- New tank top handrail, tank top stairs/walkway and tank top access platform to preform inspections and maintenance.
- Jib crane to safely move materials to and from the tank top area.
- Engineering safety tie off anchors for future tank work.
- Provide safer access for emergency personnel.

Division 1-38, page 2

The existing stairs will remain for a second access point during emergencies.

This new design will increase safety for the plant personnel and support future upgrades to the equipment located on the top area of the LNG tank.

Regarding the requested documentation, Rhode Island Energy does not have a firm quote for this specific project. After consulting with a leading construction firm that installs these systems, the estimate for this project is approximately $2.5 million. The full amount of $3.33 million includes overheads and design fees.

(b) New Control Room

A control room upgrade is needed at the Exeter LNG Facility to provide a safe operating environment for our employees. This upgrade will replace the original control room built in 1971. To maintain operational functionality, a new control room is being selected, instead of modifying the current control room for the following reasons:

- Motor Control Center (MCC) and Process Logic Controller (PLC) equipment is in the current control room adjacent to the operator station. There is no arc flash protection and there is no space to install an engineered barrier in the current building. Moving the control room will eliminate this hazard.

- There is no space in the current footprint to create workspaces that are consistent with a modern control room layout. Currently, the amount of information that can be displayed is restricted to two monitors for each station. Modern ergonomics were not considered with the current control room layout. The original control room used pneumatic controls and was not sized for Human Machine Interface (HMI) workstations.

- Building a new control room allows the current control room to remain functional until the new one is completed; this keeps the plant fully operational with minimum work required for a switch over. This is in part to a new HMI system that is scheduled to be upgraded and installed in the new control room.

- Existing Control Room Building will continue to house the MCC, PLCs, and primary networking gear.

A new control room is being proposed to be built to the west of the LNG tank. The RFP for the new control room design includes the following key elements:

- Modern operator workstations for operating the HMI system.
- Offices that will have dual function for sleeping quarters during emergency operating conditions (pandemic or storm events).
- Medium size conference room (20 people).
- Records and drawing room.
- Operator training room with future provisions for a training simulator.
- LEED design and incorporation of renewable energy options.
- Workshop.

Design will also include a future layout for the storage and operation of future portable LNG equipment. This is included to achieve cost savings with utility service layouts and attain maximum arrangement efficiency if portable equipment is to be used in instances of maintenance/construction or an emergency situation.

Regarding the requested documentation, Rhode Island Energy does not have a firm quote for this specific project and has prepared a detailed design RFP with cost estimate that is being issued shortly. Cost estimates include environmental permitting and requirements to develop the proposed area. The Company developed the proposed budget of $9.17 million based on historical estimates for similar LNG projects.

(c) New Truck Station

A new truck station that incorporates modern safety standards is needed to replace the original truck station. A modern truck station will include the following:

- Automated shutdown valves for unloading and loading trucks.
- Flow meter.
- Davit arms to support hoses for hose connections.
- Truck canopy to protect operators from inclement weather.
- Fire suppression system.

In part of this design, an Automated Emergency Shutdown ("AESD") system will be incorporated into the truck station. The design will be completed for the rest of the plant and be installed at a future date.

Regarding the requested documentation, Rhode Island Energy does not have a firm quote for this specific project and will issue an RFP in FY 2024 that includes project design and cost. The Company developed the proposed budget of $10.40 million based on historical estimates for similar LNG projects.

(d) Boil-off Gas ("BOG") Compressor Upgrade

Design has been completed for adding two additional BOG compressors to replace the plant's original compressors. Key advantages over the original compressors include:

- Automated shutdown valves and system process shutdowns.
- Variable-Frequency Drive (VFD) motors for increased efficiency.
- Three 50% duty load compressor design. Only two are needed for 100% BOG, with one being an in-service spare.
- Eliminate oil carry over from the original compressors. Old compressors will be removed after new compressors are commissioned and tested for several months. This will remove the old heat exchanging system and old gas piping.

Regarding the requested documentation, the total forecasted amount for this work is $11.94 million, which is partially comprised of the $2.94 million of costs that have been incurred to date for engineering and equipment procurement. The remaining $9.00 million includes compressors, ancillary equipment, owner's engineer, building, construction costs, and overheads. Costs may increase once the construction phase is awarded next year. See Attachment Division 1-38-2 for a copy of the cost estimate for the BOG Compressor for additional detail.

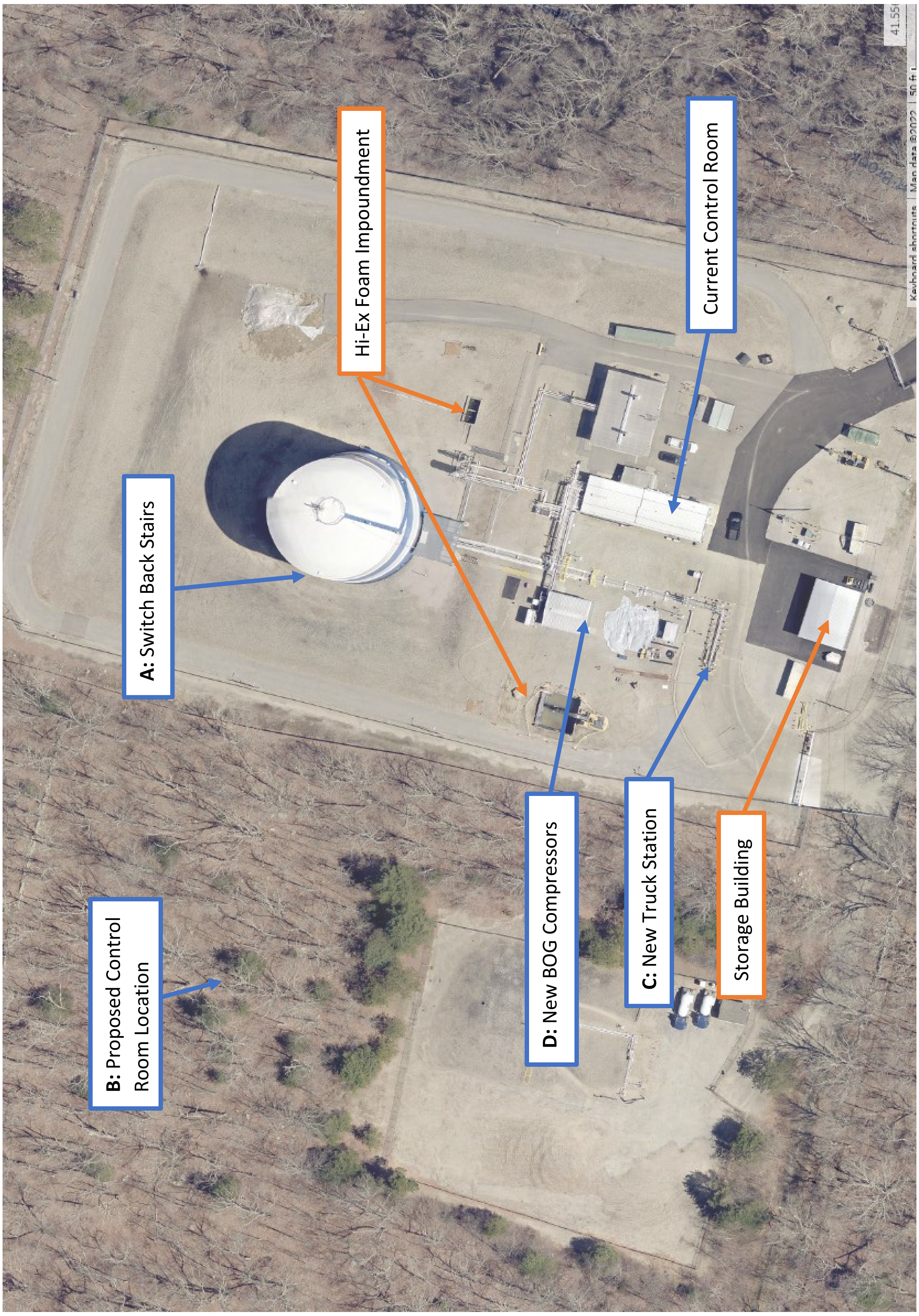
(e) Please see Attachment Division 1-38-3 for a copy of the study initiated by National Grid. Please note this study only included an assessment of the LNG tank and immediate LNG pump out equipment. The study does not refer to the projects discussed in the responses to parts (a) – (d), above.

Attachments Division 1-38-2 and Division 1-38-3 contain commercially sensitive and confidential information. The Company is providing this information to the Division pursuant to

Division 1-38, page 5

the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022.

EXETER LNG


Hi-Ex Foam Impoundment
Current Control Room
A: Switch Back Stairs
B: Proposed Control Room Location
D: New BOG Compressors
C: New Truck Station
Storage Building

nationalgrid

Estimate Summary

C079870-Exeter Boil Off Gas Compressor-4.3

Utility	Gas	Proj Number		Est Number	
Proj Type	LNG and CNG	Funding Proj	C079870	Est Stage	4.3
Proj Lead	Thorne, John	Work Order	90000192072	Est Version	1
Estimator	Stewart, Alexandra	State	RI	Est Type	Complex
Company	5360 - Narragansett Electric Company	Fiscal Yr	2024	Last Update	7/5/2022 5:39:36 PM
Base Template	Gas - 5360 - RI - NARR Gas - Oct 2021				

		CAP	OPE	COR	Total
Labor - Management		518,592	-	-	518,592
Labor - Craft		207,562	-	5,489	213,051
Material - Stock		-	-	-	-
Material - Non-stock		591,046	-	-	591,046
Subcontractor		4,598,762	-	195,277	4,794,039
Equipment		108,179	-	1,517	109,696
Other		-	-	-	-
Subtotal (by Category)		**6,024,141**	**-**	**202,283**	**6,226,424**
Material Tax	7.00%	41,373	-	-	41,373
Stores Material Handling	15.00%	-	-	-	-
Overhead - Management	85.90%	445,470	-	-	445,470
Overhead - Craft	71.20%	147,784	-	3,908	151,692
COD	29.00%	1,931,043	-	-	1,931,043
A&G	1.88%	125,185	-	-	125,185
AFUDC	-	733,148	-	-	733,148
Escalation	9.34%	872,420	-	29,295	901,715
Base Total		**10,320,565**	**-**	**235,485**	**10,556,050**
Contingency	5.00%	516,028	-	11,774	527,803
Base + Contingency Total		**10,836,593**	**-**	**247,260**	**11,083,853**
P50					530,568
Base + Contingency + P50 Total					**11,614,421**
P80					816,388
Base + Contingency + P80 Total					**11,900,241**

Attachment DIV 1-38

REDACTED

Prepared by or under the supervision of: Brian Kirkwood

Division 1-39

Request:

Provide all analyses (including Cost Benefit Analyses) that were performed regarding the purchase of the portable LNG equipment vs. leasing for the (a) Cumberland site; and (b) Old Mill Lane site.

Response:

The portable LNG equipment purchase and operation for Cumberland has a projected breakeven time of 7 years in comparison to leasing and utilizing contracted services. This includes four storage queens for a like to like comparison with current contracted services and equipment. The two portable vaporizers were purchased for reliability and redundancy.

Contracted operation costs for calendar year ("CY") 2022 are anticipated to increase 25% after two years when entering into a new contract, and then again after six years when another new contract would be required. Breakeven cost analyses include additional Rhode Island Energy staffing and expected O&M costs for the portable storage equipment.

Please see the Cumberland LNG Breakeven Cost Analysis provided in Attachment DIV 1-39-1 for a detailed breakdown and comparison between projected Rhode Island Energy operating model costs versus contracted services operating costs. At year seven, the cost of purchased equipment and using Rhode Island Energy staffing will have been recovered when compared to the projected accumulated contracting services cost. After year seven, Rhode Island Energy is projected to only spend approximately $56,400 dollars per year for the same operation that contracted services is estimated to cost $898,656. This comparison only reviews costs and does not address additional operating redundancy that the purchased equipment has over contracted equipment experienced to date.

The purchase and operation of portable LNG equipment at Old Mill Lane has a projected breakeven point of four years.

Contract costs are for operation in CY 2022 and are anticipated to increase 25% after two years when entering into a new contract. Breakeven cost analyses include additional Rhode Island Energy staffing and expected O&M costs for the portable storage equipment.

Please see the OML LNG Breakeven Cost Analysis provided in Attachment DIV 1-39-2 for a detailed breakdown. At year four, the cost of purchased equipment and using Rhode Island

Division 1-39, page 2

Energy staffing will have been recovered when compared to the projected accumulated contracting services cost. After year four, Rhode Island Energy is projected to only spend approximately $223,600 dollars per year for the same operation that contracted services is estimated to cost $3,011,675. This comparison only reviews costs and does not address additional operating redundancy that the potential purchased equipment has over contracted equipment experienced to date.

Cumberland LNG

Equipment cost: 4.15 Million - (4) Smart Storage Queens, including 25% OH

Breakeven with 2 extra mobilization

Year	Contractor Service	Cost	RIE Cost	Cost	Runing Cost	Breakeven Cost	Comments
1	Seasonal Service Operation	-319,580	Additional Labor	36,400			
	Out of season service Operation	-255,560	O&M	20,000			
	Annual Cost	**-575,140**	Annual Cost	**56,400**	**-518,740**	**3,631,260**	
2	Seasonal Service Operation	-319,580	Additional Labor	36,400			
	Out of season service Operation	-255,560	O&M	20,000			
	Annual Cost	**-575,140**	Annual Cost	**56,400**	**-1,037,480**	**3,112,520**	
3	Seasonal Service Operation	-399,475	Additional Labor	36,400			Contract cost increase 25%
	Out of season service Operation	-319,450	O&M	20,000			
	Annual Cost	**-718,925**	Annual Cost	**56,400**	**-1,700,005**	**2,449,995**	
4	Seasonal Service Operation	-399,475	Additional Labor	36,400			
	Out of season service Operation	-319,450	O&M	20,000			
	Annual Cost	**-718,925**	Annual Cost	**56,400**	**-2,362,530**	**1,787,470**	
5	Seasonal Service Operation	-399,475	Additional Labor	36,400			
	Out of season service Operation	-319,450	O&M	20,000			
	Annual Cost	**-718,925**	Annual Cost	**56,400**	**-3,025,055**	**1,124,945**	
6	Seasonal Service Operation	-399,475	Additional Labor	36,400			
	Out of season service Operation	-319,450	O&M	20,000			
	Annual Cost	**-718,925**	Annual Cost	**56,400**	**-3,687,580**	**462,420**	
7	Seasonal Service Operation	-499,344	Additional Labor	36,400			Contract cost increast 25%
	Out of season service Operation	-399,313	O&M	20,000			
	Annual Cost	**-898,656**	Annual Cost	**56,400**	**-4,529,836**	**-379,836**	Breakeven year for purchasing equipment and staffing entirely with RIE
8	Seasonal Service Operation	-499,344	Additional Labor	36,400			
	Out of season service Operation	-399,313	O&M	20,000			
	Annual Cost	**-898,656**	Annual Cost	**56,400**	**-5,372,093**	**-1,222,093**	Savings per year to customer

OML LNG

Equipment cost: 9.15 Million - (2) 750 MSCFH Vaporizers & (6) Smart Storage Queens, including 25% OH

Breakeven with 2 extra mobilization

Year	Contractor Service	Cost	RIE Cost	Cost	Running Cost	Breakeven Cost	Comments
1	Seasonal Service Operation	-1,487,340	Labor (less current costs)	198,660			
	Out of season service Operation	-922,000	O&M	25,000			
	Annual Cost	**-2,409,340**	Annual Cost	**223,660**	**-2,185,680**	**6,964,320**	
2	Seasonal Service Operation	-1,487,340	Labor (less current costs)	198,660			
	Out of season service Operation	-922,000	O&M	25,000			
	Annual Cost	**-2,409,340**	Annual Cost	**223,660**	**-4,371,360**	**4,778,640**	
3	Seasonal Service Operation	-1,859,175	Labor (less current costs)	198,660			Contract cost increase 25%
	Out of season service Operation	-1,152,500	O&M	25,000			
	Annual Cost	**-3,011,675**	Annual Cost	**223,660**	**-7,159,375**	**1,990,625**	
4	Seasonal Service Operation	-1,859,175	Labor (less current costs)	198,660			
	Out of season service Operation	-1,152,500	O&M	25,000			
	Annual Cost	**-3,011,675**	Annual Cost	**223,660**	**-9,947,390**	**-797,390**	Breakeven year for purchasing equipment and staffing entirely with RIE
5	Seasonal Service Operation	-1,859,175	Labor (less current costs)	198,660			
	Out of season service Operation	-1,152,500	O&M	25,000			
	Annual Cost	**-3,011,675**	Annual Cost	**223,660**	**-12,735,405**	**-3,585,405**	Savings per year to customer

Division 1-40

Request:

Identify: (a) the number of days the Cumberland Portables LNG tanks have run in each of the past 5 years, (b) the hours for each day that they have run, (c) the number of trucks that have been used to refill the tanks for each day identified, (d) identify and describe all difficulties the Company has encountered engaging trucking firms to effect re-fill, and (e) provide documentation that supports the $3.50 M budget to add Supplemental Storage for the Cumberland site.

Response:

(a) As noted in the table below, the number of days the Cumberland Portables LNG tanks have run in each of the past five years is 14 days.

(b) Please see the table below.

(c) Please see the table below.

(d) Over the past few years, the Company has not encountered difficulties in engaging or contracting with trucking firms to effect re-fill. The Company continues to finalize its trucking service for this winter refill period of December 2022 through March 2023 as LNG trucking firms, similar to other industries, are experiencing challenges with the availability of resources.

(e) On site storage is limited to five hours run time at maximum send out rate (750 Million Standard Cubic Feet per Hour - MSCFH). Increasing onsite storage will increase maximum rate runtime to ten hours. This provides greater flexibility with receiving additional LNG deliveries because of inclement weather, or other delays, to ensure enough LNG is maintained onsite.

The chart below describes LNG trucking needs for Cumberland. To create the level of supply described in the current supply portfolio, a total of 11 trucks is required to be delivered to Cumberland for 68 HDD conditions, five to fill prior to start of the design day and six during the course of the design day. Relying on six additional deliveries throughout the course of an extreme cold weather event day introduces risk to the ability of the site to send out the necessary level of supply, including, but not limited to, road conditions or roadway closures, inclement weather (storms, winds), truck or driver availability, availability from supplier, or other unforeseen issues. Increasing on-site storage increases the number of trucks that can be delivered in the days leading up to a cold weather event and reducing the requirement of six trucks during the course of the day to less than one, reduces the risks of delivery to the site.

In FY 2023, the Company moved forward with the purchase of a portable LNG equipment setup for the Cumberland location. The Company utilized the unit pricing of the portable storage included in that purchase as the basis for the $3.50 million budget to add Supplemental Storage for the Cumberland site.

Rhode Island Winter 2022/23 Portable LNG Needs									
Current Inventory 22-23	Forecasted # of Days	Estimated # of Hours	Peak Hour Flow (Dth/hr)	Portable LNG Supply Need Dth	Onsite Storage Equivalent Dth	Calculated # Trucks	Total Calc # Trucks	Actual # Trucks	Actual LNG Dth (4)
Cumberland Testing	NA	4	750	3,000	3,000	-	3.16	4	3,800
Cumberland 68 HDD Peak Day Requirement	1	14	750	10,179	4,691	5.78	10.71	11	10,450
Cumberland 68 HDD Peak Day Requirement Contingency	1	14	750	10,179	4,691	5.78	10.71	11	10,450
Cumberland 61 HDD Requirement	1	24	345	2,050	4,691	(2.78)	2.16	3	2,850
Cumberland 61 HDD Requirement Contingency	1	24	345	2,050	4,691	(2.78)	2.16	3	2,850
Subtotal Cumberland	4	76		27,457				32	30,400
Expanded Inventory									
Cumberland Testing	NA	4	750	3,000	3,000	-	3.16	4	3,800
Cumberland 68 HDD Peak Day Requirement	1	14	750	10,179	9,382	0.84	10.71	11	10,450
Cumberland 68 HDD Peak Day Requirement Contingency	1	14	750	10,179	9,382	0.84	10.71	11	10,450
Cumberland 61 HDD Requirement	1	24	345	2,050	9,382	(7.72)	2.16	3	2,850
Cumberland 61 HDD Requirement Contingency	1	24	345	2,050	9,382	(7.72)	2.16	3	2,850
Subtotal Cumberland	4	76		27,457				32	30,400

Division 1-40, page 3

Cumberland LNG

Date	LNG Trucks Deliveries	Vaporization Hours	Comments
12/20/2017	1	2.5	Test Run
12/21/2017	1	3	
12/27/2017	2		
12/28/2017	1		
12/29/2017		3.5	
1/3/2018	2		
1/7/2018		10	
12/11/2018	2	3.5	Test Run
1/21/2019	4		
1/22/2019		9	
1/30/2019	4		
1/31/2019		5	
2/1/2019		6	
11/27/2019	2	3	Test Run
11/25/2020	2	3	Test Run
11/29/2021	2	4	Test Run
1/10/2022	4		
1/13/2022		3	
1/14/2022		2	
1/15/2022		7	
11/30/2022	1	3	Test Run
TOTAL	28	67.5	

Prepared by or under the supervision of: Brian Kirkwood

Division 1-41

Request:

Referring to Page 37, has the Company been directed by the Navy to decommission the LNG site? Provide the Company's Lease with the Navy that is coming to an end for this site. Provide documentation that supports the $2.73 M to decommission this site.

Response:

The Company's lease with the Navy will expire in 2026. The Company is proactively developing a decommissioning scope to remove all added equipment and return the site to the original condition prior to developing the site for LNG use.

The Company is preparing an RFP for decommissioning and demolition and has been working with the Navy. The RFP will include an estimated decommissioning and demolition cost estimate. The Company has adjusted its estimates to $1.25 million for the 21-month forecast after further discussions with the Navy. This includes the expected costs for environmental compliance at the site during demolition. The site had soil contamination prior to the Company's involvement with the property and may require additional precautions so as not to disturb the contaminants. Any special environmental considerations will be coordinated with the Navy.

Please see Attachments Division 1-41-1, Division 1-41-2 and Division 1-41-3 for copies of the Operating Agreement, General Purpose Lease, and Grant of Easement, respectively, between Southern Union Company — New England Division d/b/a Providence Gas Company ("Providence Gas"), as predecessor to the Company, and the Navy. Attachments Division 1-41-1 and Division 1-41-2 contain commercially sensitive and confidential information. The Company is providing this information to the Division pursuant to the global Nondisclosure Agreement between the Company and the Division dated February 13, 2020, as amended on November 30, 2022.

Please also see Attachment Division 1-41-4 for a copy of the Soil Management Plan.

OPERATING AGREEMENT
BETWEEN
COMMANDING OFFICER, NAVAL STATION NEWPORT
AND
PROVIDENCE GAS COMPANY
FOR THE
LIQUIFIED NATURAL GAS TRANSFER STATION
LOCATED AT NAVAL STATION NEWPORT

GENERAL: This Operating Agreement is made and entered into this 13 day of September, 2001 between the NAVY, represented by the Commanding Officer, Naval Station Newport, Newport, R.I. (STATION) and the Southern Union Company – New England Division d/b/a/ Providence Gas Company (PROVGAS). Nothing in this agreement shall supercede, limit or alter the terms and conditions of the Real Estate Contracts providing land rights and responsibilities. In the event of a conflict in the interpretation of any language between this agreement and a real estate contract, the real estate contract are agreed by all parties to be controlling.

AUTHORITY: This agreement is entered into pursuant to the to the following directives insofar as they are applicable.

REFRENCES:
(a) NAVSTAINST 5530.5, NETC Physical Security
(b) OPNAVINST 5530.14B, Navy Physical Security
(c) NAVSTAINST/LOCAL AREA COORD 5090.1, Oil and Hazardous Substance Spill
(d) OPNAVINST 5090.1B, DON Environmental Manual

Additional Environmental references are listed in Exhibit A, attached.

FACILITY DECRIPTION: The Liquefied Natural Gas (LNG) transfer station shall provide supplementary natural gas for Aquidneck Island during periods of high demands (typically the coldest periods in the winter, normally 8-10 days per year). The transfer station shall consist of a truck unloading area, a LNG pumping vaporization system, a sendout metering and odorization system, a control facility, a hazardous detection system, a security system, an emergency shutdown system and necessary control valves, instrumentation and associated piping and attachments. The LNG transfer station shall be enclosed within a security fence and shall be equipped with an industry-approved fire and gas detection equipment. The facility shall be located on approximately a 4.2 acre parcel located at the Coddington Cove portion of the Naval Station Newport in the Town of Middletown, RI.

COMPENSATION FOR ALLOWING THE FACILITY TO BE PLACED ON STATION PROPERTY: The total compensation that PROVGAS, it assigned, heirs and designees is providing to the United States Of America for the right to place and operate the Facility, inclusive of real estate and non-real estate property considerations, is valued at $[redacted] and is comprised of five components as follows and as further explained in paragraphs below.

1) Value for the Easement Rights for a pipeline ($[redacted]

2) Value for the Lease Rights for the main facility site expressed as an accelerated net present value in place of annual rents ($[redacted]

3) Reimbursement of the Navy Administrative Expenses ($[redacted]

4) Establish Utilities ($[redacted]) and annual reimbursement of operating expenses ($[redacted]

5) Performance of a Demand Side Management Feasibility Study at [redacted] modification to the Navy being executed under Contract # N62470-99-C-3635-JN-03 ($[redacted].

REIMBURSEMENT FOR NAVY ADMINISTRATIVE COSTS FOR PROCESSING AND EXECUTING LNG REAL ESTATE CONTRACTS: PROVGAS shall reimburse the Navy for administrative costs incurred during the processing and executing of real estate contracts (easement and lease) for the LNG Facility. The price for this cost, broken down by the Navy Activity, is detailed below.

Cost Calculation for Reimbursement of Navy Administrative Expenses

Activity	Cost
LANTDIV	$ [redacted]
Northeast Region	$ [redacted]
Atlantic Fleet	$ [redacted]
Naval Station Newport	$ [redacted]
Total	$[redacted]

PROVGAS shall make cash payment to the Naval Station Newport in accordance with Navy financial requirements no later than 31 October 2001. This payment will be disbursed to the above Naval Activities by the STATION.

OPERATING AGREEMENT SERVICES / ITEMS:

1. **SECURITY SERVICES:** The STATION shall be responsible for the physical security of its jurisdiction in accordance with references (a) and (b) and shall maintain routine security patrols around the security fence perimeter of the LNG transfer station. PROVGAS shall develop and maintain a physical security plan for their assets within their fenced in area. The NAVY shall provide routine perimeter security patrols at no additional cost. PROVGAS shall reimburse the NAVY for special security services such as opening and closing of locked gates after normal working hours to enable LNG transfer trucks access into the facility. PROVGAS shall provide a key for access into the facility to the NAVY Police Department.

PROVGAS shall notify the NAVY Police Department via a phone call to the NAVY Police Dispatch Office if a police unit should be dispatched to the LNG transfer station. PROVGAS shall monitor its own security system at the PROVGAS central monitor station in Providence, RI. PROVGAS shall decide whether the alarm condition warrants NAVY police dispatch. PROVGAS shall, when notifying the NAVY, provide the nature of the emergency based on the alarm received. The NAVY shall be reimbursed on a yearly basis for being on stand-by and responding to all calls (on a reasonable basis). [redacted] The estimated cost for this service is provided within Exhibit B.

PROVGAS shall cooperate with the Naval Criminal Investigative Service personnel and the Police Protection Branch for any criminal investigations involving PROVGAS personnel or equipment. PROVGAS personnel shall register business and personal vehicles used to access their facilities with the NAVY Pass and Decal Office referencing the lease.

2. **FIRE PROTECTION**: The NAVY shall provide fire protection services for the LNG transfer station on a yearly reimbursable basis. The estimated cost for this service is provided within Exhibit B. This includes 24 hours per day fire and hazardous material incident response and emergency medical response as well as monthly fire inspections. PROVGAS shall comply with all NAVY directives. PROVGAS shall provide a key for access into the facility to the NAVY Fire Department.

PROVGAS shall provide or fund training for NAVY Fire Department personnel. Training shall consist of (a) one day training class to a core group of approximately 30 NAVY Fire Department personnel so they can adequately respond to emergencies at the LNG station (class may have to be held multiple times); (b) PROVGAS shall provide a 2-day LNG fire fighting course offered at the Massachusetts Fire Fighting Academy (Stowe, MA) for a minimum of four NAVY Fire Department personnel. This training shall be provided on an annual basis. PROVGAS shall reimburse the NAVY for all travel, labor and lodging incurred by NAVY personnel in attending these training classes. The estimated cost for this reimbursement is provided within Exhibit B.

PROVGAS shall provide all fire protection, emergency response and operations and maintenance plans to the NAVY for approval prior to the operation of the facility.

3. **SPILL RESPONSE**: The NAVY shall maintain full response capability for spills within and migrating on to the LNG transfer station. PROVGAS shall reimburse the NAVY yearly for all expenses incurred to have required response equipment on-hand and to be prepared to respond to any spills caused by PROVGAS, it assigns, agents or representatives. PROVGAS shall (a) comply with all NAVY directives; (b) arrange for cleanup of any spilled materials; (c) notify the NAVY and proper authorities of spill occurrence and prepare reports for regulatory agencies as required; (d) ensure that PROVGAS LNG Operators are trained as first responders awareness levels for spills and notify NAVY Fire Department immediately at 841-3333 when spill occurs or is discovered; (e) provide updates to the NAVY Spill Response Plan as required to address potential spills at the facility.

4. **SAFETY**: PROVGAS shall administer and manage it's own safety program requirements as identified in applicable federal, state and local regulations. The PROVGAS shall provide a copy of its LNG transfer station safety program to the NAVY Safety Department.

5. **DISASTER PREPAREDNESS**: The PROVGAS shall be responsible to protect life, PROVGAS assets, and Government property within the fence line of the LNG transfer facility. PROVGAS shall develop and implement disaster preparedness plans that fulfill the requirements of the NAVY Disaster Preparedness Plan (NAVY shall provide copy to PROVGAS). PROVGAS shall participate in exercises and assist, as required, by NAVY directives. PROVGAS shall prepare and submit a Disaster Preparedness Plan in accordance with the NAVY Disaster Preparedness Plan. The plan is subject to NAVY approval.

6. **PUBLIC AFFAIRS**: The NAVY shall provide guidance to PROVGAS on all local news situation/press interest policy pertaining to operations at this facility and the working relationship with the NAVY. The NAVY Public Affairs Officer shall be the sole point of contact for any official press releases as they pertain to operations on the NAVY facility. PROVGAS shall refer

all outside inquiries regarding NAVY activities to support the LNG transfer station to the NAVY Public Affairs Officer.

7. **TELEPHONE / EQUIPMENT SERVICE:** PROVGAS is solely responsible for procuring telephone/communications services through a commercial provider. On a reimbursable basis the NAVY shall provide initial phone line connection to the NAVY telephone grid.

8. **UTILITIES:** All utilities provided by the NAVY to PROVGAS are reimbursable.

a. Electricity: The NAVY shall provide the initial electrical power connection to the NAVY electrical distribution system. The estimated cost for this work (electric, fire alarm and telephone) is provided within Exhibit B. The NAVY shall bill the PROVGAS on a quarterly basis based on metered electrical consumption at the privacy party rate. The current private party rate is $ [redacted]/MWH and is subject to change provided a 90-day advance notice is given by the NAVY. The NAVY and PROVGAS shall sign a utility sales agreement which will allow the NAVY to sell electricity to Prov Gas. This agreement will be prepared by LANTDIV Utilities.
b. Water: Not required.
c. Sewer: Not required.
d. Fire Alarm: A radio alarm box shall be installed which will communicate with the NAVY Fire Department.
e. Storm Drainage: Not required. PROVGAS shall utilize existing system. Any additional upgrades to the storm drainage system shall be provided by the PROVGAS with prior NAVY approval.
f. Fire Protection: New fire hydrants are not required. PROVGAS shall reimburse the NAVY to repair any existing hydrants if required.
g. Refuse Collection/Recycling Removal: PROVGAS shall provide for their own refuse collection and recycling services as required.
h. Street Sweeping and Snow Plowing: On a yearly reimbursable basis the NAVY shall provide snow plowing, sanding and street sweeping services for the road leading up to the facility main gate past Building 6. The estimated cost for this service is provided within Exhibit B. The PROVGAS shall be responsible for snow plowing and street sweeping within the fence line of the facility.

9. **LNG TRANSFER STATION MAINTENANCE:** PROVGAS shall be responsible for the maintenance of all PROVGAS assets within the fence line of the facility. ~~PROVGAS shall provide a copy of the facility Operations and Maintenance Plan to the NAVY.~~

10. **ROAD MAINTENANCE:** PROVGAS shall maintain all roads and other surfaces within the fence line of the facility. On a yearly reimbursable basis the NAVY shall maintain all roads that shall be used for access by PROVGAS into the facility. The estimated cost for this service is provided within Exhibit B.

11. **PEST CONTROL:** PROVGAS shall provide for their own pest control services. The PROVGAS shall advise the NAVY what pest control measures they are applying within the fence line of the facility.

12. **GROUND MAINTENANCE AND LANDSCAPING:** PROVGAS shall provide services in control of vegetation overgrowth and maintain ground cover for erosion control within the fence line of the facility.

13. **INSTALLATION RESTORATION PROGRAM REQUIREMENTS:** The NAVY will be responsible for management of the Installation Restoration Program at the NAVY including the PROVGAS operated LNG transfer facility. PROVGAS shall comply with all NAVY directives.

14. **ENVIRONMENTAL PROGRAM COMPLIANCE:** PROVGAS is responsible to comply with all applicable environmental laws, standards, rules, and regulations, permit conditions and policies. PROVGAS shall make environmental compliance requirements that pertain to the LNG transfer facility known to the NAVY. In addition, the PROVGAS shall be responsible for obtaining all necessary environmental permits to operate the LNG transfer station (i.e. air permits, hazardous waste, etc.). However, known industrial wastewater discharges must be permitted through the NAVY. PROVGAS shall supply copies of all permits to the NAVY. PROVGAS shall reimburse the NAVY for fines or migration expenses that the NAVY receives as a direct result of PROVGAS action or non-action. PROVGAS shall comply with following additional requirements:

a. Notify the NAVY if it receives a Notice of Violation for operations at the facilities.
b. Notify the NAVY if any pollutants or industrial wastewater are discharges into storm water collection system, the sewerage collection system and the water of the state.
c. Notify the NAVY of any future activities that require National Environmental Policy Act approvals.
d. Notify the NAVY if natural resources, historical structures, or cultural artifacts are discovered or disturbed.
e. Notify the NAVY if air pollution control equipment malfunctions or other problems occur.
f. Notify the NAVY when implementing changes that generate noise.
g. Notify and obtain NAVY approval for tank systems and tank alterations.
h. Notify the NAVY during planning stages of construction activities.

15. **KEY OFFICIALS:**

The key officials from the STATION will be:

CAPT [redacted], COMMANDING OFFICER, NAVSTANPT **401-[redacted]**
[redacted], DIRECTOR OF ENGINEERING **401-[redacted]**
[redacted], PLANNING BRANCH HEAD **401-[redacted]**
[redacted], ENVIRONMENTAL DEPARTMENT HEAD **401-[redacted]**

The key officials from PROVGAS will be:

[redacted], VICE PRES. TECHNOLOGY, REGULATORY AND GAS SUPPLY **401-272-5040**
[redacted], DIRECTOR SYSTEMS PLANNING **401-272-5040**
[redacted], LNG OPERATIONS AND MAINTENANCE **401-272-5040**

16. **OPERATING SERVICES FUNDING AND REIMBURSEMENT ARRANGEMENT:**

a. For the Establishment of Electrical Services in accordance with paragraphs #7., #8.a., and #8.d. above; a one-time payment in cash in the amount of $[redacted] is to be made to the STATION no later than 31 October 2001.

b. For the annual expenses of the STATION in providing other services and items as detailed above, PROVGAS will make annual payments in cash, with a first year payment of $[redacted] to the STATION, due no later than 31 October 2001. Subsequent annual payments shall be made by PROVGAS to the STATION for each year this operating agreement is in force based upon estimates provided by the STATION.

c. An annual payment estimate will be provided for each year's projected expenses under paragraph #16.b. above to allow for increases in the actual expenses incurred as a result providing the services and items under this agreement. This estimate will be provided by the NAVY to PROVGAS by October 15th of each year with payment due by October 31st of each year. Adjustments between the estimated and actual for the prior year will be credited or debited towards the estimate on the following year, excepting for the final year of this agreement for which no adjustment is to be made.

PERFORMANCE OF A DEMAND SIDE MANAGEMENT FEASIBILITY STUDY:
PROVGAS will provide the STATION with a completed Demand Side Management Feasibility Study (DSM) under a [redacted]y modification to the Navy Utilities Contract # N62470-99-C-3635-JN-04, with an agreed credited valuation of $[redacted] as partial in-kind consideration for the placement, operation and other non-real estate related considerations regarding locating the LNG facility on Navy Property. This DSM shall be performed and provided by PROVGAS in accordance with the attached Exhibit C "DSM Scope of Work" dated 11 July 2001.

DEPARTMENT OF THE NAVY

[redacted] Date
Commanding Officer, Naval Station Newport
Newport, RI

PROVIDENCE GAS COMPANY

Date

Attachments:

Exhibit A – Environmental Reference List
Exhibit B – Operating Agreement Cost Estimates
Exhibit C – DSM Scope Of Work

EXHIBIT A

ENVIRONMENTAL REFERENCE LIST

A) OPNAV5090.1B, ENVIRONMENTAL AND NATURAL RESOURCES MANUAL
B) OPNAV5090.23D, NAVOSH MANUAL
C) NAVSTANPT 5090.1A, CONTINGENCY PLANNING
D) NAVSTANPT 5090.2C, AIR EPISODE PLAN
E) NAVSTANPT 5090.3C, RECYCLING MATERIALS PROGRAM
F) NAVSTANPT 5090.4, HAZARDOUS WASTE MINIMIZATION PLAN
G) NAVSTANPT 5090.5C, HAZARDOUS WASTE MANAGEMENT
H) NAVSTANPT 5090.8C, UNDERGROUND AND ABOVEGROUND STORAGE TANK MANAGEMENT
I) NAVSTANPT 5090.9, LEAD PAINT ABATEMENT PROGRAM
J) NAVSTANPT 5090.10, OZONE DEPLETING SUSNSTANCES MANAGEMENT PLAN
K) NAVSTANPT 5090.11, POLLUTION PREVENTION PLAN
L) NAVSTANPT 5090.12, REGULATED MEDICAL WASTE
M) NAVSTANPT 5090.13, SOLID WASTE MANAGEMENT
N) NAVSTANPT 4400.3, HAZARDOUS MATERIAL SHELF LIFE EXTENSION
O) NAVSTANPT 5090.14A, HAZARDOUS MATERIAL AND CONTROL AND MANAGEMENT
P) EXECUTIVE ORDER 12586 (EMERGENCY PLANNING AND COMMUNITY RIGHT TO KNOW ACT)
Q) CFR, 40 CFR, 49 CFR
R) NAVMEDCOMINST 6280.1
S) NATAIONAL FIRE PROECTION ASSOCIATION STANDARDS
T) OPNAVINST 4110.2
U) SECNAVINST 6210.2
V) OPNAVINST 5100.19C
W) OPERATING AIR PERMIT
X) RHIDE ISLAND AIR POLLUTION CONTROL REGULATIONS
Y) SPILL CONTINGENCY PLAN
Z) SPILL PREVENTION COUNTERMEASURES AND CONTROL PLAN
AA) DOD 4150.7; DOD PEST MANAGEMENT PROGRAM
BB) OPNAVINST 6250.4A, PEST MANAGEMENT PROGRAMS
CC) DOD 4150.7-M, PLAN FOR CERTIFICATION OF PESTICIDE APPLICATION OF RESTRICTED USE PERSTICIDE
DD) RHODE ISLAND RULES AND REGULATIONS FOR UNDERGROUND STORAGE FACILTIES USED FOR PETROLEUM PRODUCTS
EE) RHODE ISLAND OIL POLLUTION CONTROL ACT
FF) RHODE ISLAND RULES AND REGULATIONS FOR LEAD POISSONING PREVENTION
GG) AMERICAN WATER WORKS ASSOCIATION STANDARDS

NAVFAC 11011/24 (10-72)

DEPARTMENT OF THE NAVY GENERAL PURPOSE LEASE PART 1

EAFNE FILE NO. LO-0019
LANTDIV FILE NO: LO-0410
CONTRACT NUMBER
N62470-01-RP-00175

LEASE BETWEEN **Southern Union Company - New England Division**
d/b/a
Providence Gas Company (PROVGAS)
100 Weybosset Street
Providence, RI 02903

(HEREINAFTER CALLED "LESSEE") AND THE UNITED STATES OF AMERICA (HEREINAFTER CALLED THE "GOVERNMENT"), CONSISTING OF THIS PART 1, GENERAL PURPOSE LEASE, AND PART 2, THE GENERAL PROVISIONS OF THE GENERAL PURPOSE LEASE (NAFVAC 11011/24A), AS MODIFIED AND ATTACHED HERETO AND MADE A PART HEREOF.

1. **LEASED PROPERTY**: UNDER THE TERMS AND CONDITIONS OF THIS LEASE, THE GOVERNMENT HEREBY LEASES TO THE LESSEE THAT PORTION OF THE

Newport Naval Station, located in the Town of Middletown, County of Newport, State of Rhode Island,

(HEREINAFTER CALLED THE "STATION") HEREINAFTER DESCRIBED, WHICH PORTION IS HEREINAFTER CALLED THE "LEASED PROPERTY";

together with said use, purposes and terms and conditions as described in Part 2, The General Provisions attached to this Lease; and

AS DELINEATED ON THE MAP OF THE LEASED PROPERTY, MARKED "EXHIBIT A", AND FURTHER DELINEATED BY NARRATIVE LEGAL DESCRIPTION, MARKED "EXHIBIT B", ATTACHED HERETO AND MADE PART HEREOF;

TOGETHER WITH ALL IMPROVEMENTS THEREON AND APPURTENANCES THEREUNTO BELONGING.

TOGETHER WITH THE RIGHTS OF INGRESS AND EGRESS AND THE RIGHT, IN COMMON WITH OTHERS, TO THE USE OF ALL SUPPORTING FACILITIES AND ROADWAYS SERVING THE LEASED PROPERTY TO THE EXTENT NECESSARY TO ENABLE LESSEE TO USE SAME FOR THE PURPOSES OF THIS LEASE AND AS FURTHER SPECIFICED IN PART 2, THE GENERAL PROVISIONS.

ATTACHED HERETO AND MADE PART HEREOF IS A CONDITION REPORT, MARKED "EXHIBIT C", SIGNED BY THE REPRESENTATIVES OF THE GOVERNMENT AND LESSEE, WHICH SETS FORTH THE CONDITION OF EACH ITEM OF THE LEASED PROPERTY AS DETERMINED FROM THEIR JOINT INSPECTION THEREOF.

2. **TERM:** THE TERM OF THIS LEASE SHALL FOR TWENTY-FIVE (25) YEARS TO BEGIN ON September 13th, 2001 AND END ON September 12th, 2026 UNLESS SOONER TERMINATED IN ACCORDANCE WITH THE TERMINATION CLAUSES OF PART 2, THE GENERAL PROVISIONS HEREOF.

UPON WRITTEN MUTUAL AGREEMENT ON COMPENSATION AND THE NEED TO EXTEND THIS LEASE, THE GOVERNMENT AND LESSEE MAY EXTEND THE TERM OF THIS LEASE, UNDER THE SAME TERMS AND CONDITIONS, FOR AN ADDITIONAL TWENTY-FIVE (25) YEARS WITH SAID MUTUAL AGREEMENT TO BE EXECUTED NO LATER THAN NINETY (90) DAYS PRIOR TO THE EXPIRATION OF THE CURRENT TERM; PROVIDED, NO EXTENSION SHALL BE GRANTED WHICH CREATES A TOTAL TERM IN EXCESS OF FIFTY (50) YEARS.

3. **RENT:** LESSEE SHALL PAY IN CASH RENT OR IN-KIND CONSIDERATION TO THE GOVERNMENT A NET PRESENT VALUE ONE TIME LEASE RENTAL PAYMENT OF $[redacted], SAID PAYMENT TO BE DUE NO LATER THAN OCTOBER 31, 2001 PAYABLE TO "THE UNITED STATES TREASURY". THIS ONE TIME PAYMENT OF RENT BY LESSEE IS ACCEPTED BY THE GOVERNMENT AS AN ACCELERATION OF THE PAYMENTS DETAILED IN THE ANNUAL INCOME SCHEDULE OF PAYMENTS AS DEFINED BY SEPARATE ATTACHEMENT TO THIS LEASE, IDENTIFIED AND MARKED AS "EXHIBIT D", AND IN CONFORMITY WITH ARTICLE Z. OF PART 2, THE GENERAL PROVISIONS HEREOF. "EXHIBIT D" IS ATTACHED TO PROVIDE THE BASIS FOR THE NET PRESENT VALUE DETERMINATION AND ANY FUTURE ADJUSTMENTS THAT BECOME NECESSARY.

4. **USE:** THE SOLE PURPOSE FOR WHICH LESSEE SHALL USE THE LEASED PROPERTY, IN THE ABSENCE OF PRIOR WRITTEN APPROVAL OF THE GOVERNMENT FOR ANY OTHER USE, IS:

> **Pursuant to the authority under 10 U.S.C. § 2667, wherein the LESSEE, and its successors and assigns; together with the right of ingress and egress, shall occupy the Leased Property for the sole purpose to construct, install, operate, maintain, preserve, protect, repair and replace a natural gas peakshaving facility with associated materials and equipment, herein called the FACILITY, on, in, over and under those portions of the STATION depicted on the Map, "EXHIBIT A", and described by the Narative Legal Description, "EXHIBIT B".**

5. **INSURANCE:** IN ADDITION TO THE INSURANCE REQUIREMENTS WITHIN THE GENERAL PROVISIONS, THE INITIAL MINIMUM AMOUNTS AND TYPES OF INSURANCE WHICH LESSEE AND ITS CONTRACTORS, AGENTS AND ASSIGNS, SHALL PROCURE AND MAINTAIN ON THE LEASED PROPERTY AND FOR OPERATIONS OF ANY AND ALL EQUIPMENT, VEHICLES OR FACILITIES IN ACCORDANCE WITH THE PROVISIONS OF ARTICLE C. OF PART 2, THE GENERAL PROVISIONS, HERETO ARE THE FOLLOWING:

FIRE AND EXTENDED COVERAGE	OTHER RISKS (Specify)
$ [redacted] per accident	Type: I.A.W. PART 2, THE GENERAL PROVISIONS Type: I.A.W. PART 2, THE GENERAL PROVISIONS

LIABILITY

BODILY INJURY		PROPERTY DAMAGE
$ [redacted] per person	$ [redacted] per accident	$ [redacted] per accident

THE LESSEE'S CONTRACTORS, AGENTS AND ASSIGNS SHALL ALSO OBTAIN AND MAINTAIN ADEQUATE COMMERCIAL INSURANCE COVERAGE AT OR ABOVE THE MINIMUM AMOUNTS REQUIRED UNDER THIS ARTICLE. THIS STIPULATED AMOUNT OF INSURANCE DOES NOT WAIVE OR REDUCE ANY REQUIREMENTS FOR LESSEE'S GENERAL OBLIGATION FOR REPLACEMENT, REPAIR OR COMPENSATION FOR LOSSES OR DAMAGES TO PROPERTY IDENTIFIED UNDER ARTICLE C. OR ELSEWHERE IN PART 2, THE GENERAL PROVISIONS. THESE INSURANCE REQUIREMENTS WILL BE SUBJECT TO REVIEW BY THE GOVERNMENT EVERY FIVE YEARS.

6. **SPECIAL PROVISIONS:** THERE ARE HEREBY INCORPORATED INTO THIS LEASE BY REFERENCE, RECEIPT BY THE LESSEE OF WHICH IS HEREBY ACKNOWLEDGED, THE FOLLOWING DOCUMENTS RELATING TO THE LEASED PROPERTY:

A) THE FINDING OF NO SIGNIFICANT IMPACT
B) THE FINDING OF SUITABILITY FOR LEASE
C) THE NAVY ENVIRONMENTAL BASELINE SURVEY
D) THE FEDERAL FACILITIES AGREEMENT

7. EXECUTION BY LESSEE

NAME OF LESSEE **Southern Union Company - New England Division d/b/a Providence Gas Company (PROVGAS)**

BY [redacted] (SIGNATURE) [redacted] (WITNESS)

Vice President, Finance & Regulatory (TITLE) 9/25/01 (DATE)

8. FOR CORPORATE LESSEE, CERTIFICATION BY SECRETARY OR ASSISTANT SECRETARY OF THE CORPORATION

I CERTIFY THAT THE PERSON WHO SIGNED THIS LEASE ON BEHALF OF LESSEE WAS THEN THE OFFICER INDICATED AND THIS AGREEMENT WAS DULY SIGNED FOR AND ON BEHALF OF SAID CORPORATION BY AUTHORITY OF ITS GOVERNING BODY AND IS WITHIN THE SCOPE OF ITS CORPORATE POWERS.

(CORPORATE SEAL)

[redacted] (SIGNATURE)

V.P. - Legal (TITLE)

9. EXECUTION FOR AND ON BEHALF OF THE GOVERNMENT

THE UNITED STATES OF AMERICA

BY [redacted] (REAL ESTATE CONTRACTING OFFICER) 9/18/2001 (DATE) [redacted] (WITNESS)

10. NAVY IDENTIFICATION DATA

NAME AND ADDRESS OF NAVAL STATION	LOCAL GOVERNMENT REPRESENTATIVE/ TITLE AND ADDRESS
Commanding Officer Building 690 Naval Station Newport Newport, RI 02841-1522	Commanding Officer Naval Facilities Engineering Command Engineering Field Activity Northeast [redacted]
ADDRESS OF LESSEE Southern Union Company - New England Division, d/b/a Providence Gas Company 100 Weybosset Street Providence, RI 02903	

NAVFAC 11011/24
D-11994

NAVFAC 11011/24A (Rev. 8-96)
Supersedes NAVDOCKS 2597A

DEPARTMENT OF THE NAVY
GENERAL PURPOSE LEASE
PART 2
OF
N62470-01-RP-00175
(LANTDIV FILE NO. LO-0410/EFANE FILE NO. LO-0019)

GENERAL PROVISIONS

A. GENERAL MAINTENANCE OBLIGATION

The LESSEE, at its own cost and expense, shall protect, preserve, maintain, repair and keep in good order the LEASED PROPERTY, that the same shall at all times be kept in at least as good condition as when received hereunder, as reflected in the Condition Report incorporated by Article 1 of Part 1 hereof, subject, however, to ordinary wear and tear and loss or damage for which LESSEE is not liable hereunder.

Upon completion of any construction, maintenance or repair efforts for the FACILITY, the LESSEE, at its sole expense, shall restore the LEASED PROPERTY to the same, or as good condition as existed prior to the initiation of such work.

Any property of the United States damaged or destroyed by the LESSEE incident to the use and occupation of the LEASED PROPERTY, including property on STATION land used for ingress and egress, reasonable wear and tear excepted, shall be promptly repaired, replaced, or relocated by the LESSEE to the reasonable satisfaction of and in accordance with plans and specifications previously approved by Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command or a designated local representative.

LESSEE is not responsible for preservation, maintenance or repair of the LEASED PROPERTY if related to any environmental requirements covered by or implied as a GOVERNMENT responsibility under or identified specifically within the scope of the Environmental Baseline Study, Finding Of Suitability To Lease or Federal Facilities Agreement as referenced under Article #6. of the General Lease, Part 1.

B. LESSEE PROPERTY, OPERATIONS, AGENTS AND CONTRACTORS

(1) The LESSEE shall operate and maintain the LEASED PROPERTY and FACILITY in accordance with the U.S. Department of Transportation Research and Special Programs Administration Safety Regulations Title 49 CFR part 193-Liquified Natural Gas Facilities: Federal Safety Guidelines.

(2) All equipment and improvements constructed for the FACILITY on the LEASED PROPERTY by the LESSEE hereunder shall remain the property of the LESSEE. The LESSEE shall have the right to inspect, reconstruct, remove, repair, replace, improve, relocate its property on the LEASED PROPERTY, and make such changes, alterations, substitutions, replacements, additions to or extensions of its FACILTY subject to the limitations of statute or regulation and as set forth in this Lease, including but not limited to the following:

a) Any and all improvements, repairs, relocations, reconstruction, changes, alterations, substitutions, replacements, additions to or extensions of the FACILITY; provided however that any of the foregoing actions which would result in an increase in capacity or change in emissions of the FACILITY beyond its original design level (whether performed by the LESSEE or its agents or contractors in connection with the FACILITY) is expressly prohibited without the prior written consent of the GOVERNMENT.

b) Under the terms of this Lease there shall be no permanent storage of explosive or flammable or hazardous wastes and material, such as gas, liquid or otherwise, on the LEASED PROPERTY, except as specifically incident to and necessary for the intended purpose and normal use of the FACILITY in accordance with Article D. (1) and Article AC. (3) below or as may be carried in those appropriately marked and regulated vehicles needed on a temporary basis to transfer liquefied natural gas to the FACILITY on the LEASED PROPERTY. This does not preclude the LESSEE from requesting storage under a separate Governmental application and approval process.

(3) The LESSEE may undertake all or part of the FACILITY operations on the LEASED PROPERTY or fulfill other terms of this Lease through agents or contractors; however, the LESSEE shall be solely responsible for compliance with all requirements established in this Lease. The GOVERNMENT may seek any recourse as may be allowed by applicable law against the LESSEE for the acts or omissions of the LESSEE's agents or contractors that are not consistent with the terms of this Lease.

C. RISK OF LOSS-INSURANCE

(1) The LESSEE, its agents and contractors shall assume liability for their acts or omissions incident to their ingress, egress and use of LEASED PROPERTY for the loss of, or damage to real property, and for third party bodily injury and property damage; and shall maintain a commercial insurance policy in effect sufficient to cover common business risks associated with access to and operations on the LEASED PROPERTY, at least sufficient to provide for the amounts specified under Article #5 of Part 1 of the Lease. The LESSEE, its agents and contractors shall provide such evidence as necessary to demonstrate to the satisfaction of the GOVERNMENT compliance with this requirement.

(2) LESSEE shall bear all risk of loss or damage to the LEASED PROPERTY or loss or damage to nearby GOVERNMENT real and personal property arising as a result of the LESSEE's, its Agents, Contractors or Assigns access, activities, use or possession of the LEASED PROPERTY, with or without fault by LESSEE. Notwithstanding anything to the contrary contained herein, nothing shall prevent LESSEE from exercising its legal or equitable remedies in seeking to recover any damages it may have incurred as a result of the action or inaction of the GOVERNMENT or any third party by bringing an appropriate action against the entity responsible for such damages.

(3) LESSEE shall provide, maintain, such insurance as the Local GOVERNMENT Representative may from time to time require and direct

(4) All insurance which this Lease requires LESSEE to carry on the LEASED PROPERTY shall be in such form, for such amounts, for such periods of time as the GOVERNMENT may from time to time require or approve. The LESSEE must obtain the required insurance from a company with at least a rating of "B+" or equivalent in a publicly available rating guide of insurers. Each policy of insurance shall contain a provision for thirty (30) days written notice to the Local GOVERNMENT Representative prior to the making of any material change in or the cancellation of the policy. LESSEE shall deliver promptly to the Local Government Representative a certificate of insurance or a certified copy of each policy of insurance required by this Lease and shall also deliver to him, no later than thirty (30) days prior to the expiration of any such policy, a certificate of insurance or a certified copy of each renewal policy covering the same risks. All insurance required or carried by LESSEE on any of the LEASED PROPERTY shall be for the protection of the GOVERNMENT and LESSEE against the losses incurred in connection with the LESSEE'S use of the LEASED PROPERTY. Each policy of insurance shall name the LESSEE as the insured and the United States of America (Department of the Navy) as an additional insured, and each policy of insurance against loss of or damage to the LEASED PROPERTY shall contain a loss payable clause reading as follows:

> "Loss, if any, under this policy shall be adjusted with (<u>name of lessee</u>) and the proceeds, at the election of the GOVERNMENT, shall be payable to (<u>name of lessee</u>); any proceeds not paid to (<u>name of lessee</u>) shall be payable to the Treasurer of the United States as its interests may appear."

(5) In the event that any item or part of the LEASED PROPERTY shall require repair, rebuilding or replacement resulting from loss or damage, the risk of which is assumed by LESSEE under paragraph (1) of this Article, LESSEE shall promptly give notice thereof to the Local Government Representative as to LESSEE's intent to rebuild, replace or repair the item or items of the LEASED PROPERTY so lost or damaged, as the LESSEE may elect. If the loss or damage occurs within five (5) years of the expiration of the lease term, the LESSEE may elect not to repair, rebuild or replace the FACILITY and to terminate the Lease under the LESSEE's termination rights as otherwise set forth in the General Provisions.

(6) In the event that any item, real or personal property located on the STATION outside the boundary of the LEASED PROPERTY suffers a loss or damage or shall require repair, rebuilding or replacement resulting from loss or damage, the risk of which is assumed by LESSEE under paragraph (2) of this Article, LESSEE shall promptly give notice thereof to the Local Government Representative and, to the extent of its liability as provided in paragraph (2) thereof, shall, upon demand, either compensate the GOVERNMENT for such loss or damage, or rebuild, replace or repair the item or items of the STATION so lost or damaged, as the GOVERNMENT may elect. In the event that the GOVERNMENT shall direct LESSEE to effect any repair, rebuilding or replacement which it is required to effect pursuant to this paragraph the GOVERNMENT shall direct the payment to LESSEE of so much of the proceeds of any insurance carried by LESSEE and made available to the GOVERNMENT on account of loss of or damage to any item or part of the STATION as may be necessary to enable LESSEE to effect such repair, rebuilding or replacement. In the event the GOVERNMENT shall elect not to require LESSEE to repair, rebuild or replace any item or part of the STATION lost or damaged, LESSEE shall promptly pay to the GOVERNMENT out of any insurance proceeds collected by LESSEE such portion thereof as may be allocable to loss of or damage to the STATION.

D. INGRESS, EGRESS AND RETAINED PROPERTY RIGHTS

(1) For the purpose of exercising the rights granted herein, the LESSEE or its agents or contractors shall have the right of ingress and egress to the LEASED PROPERTY, as follows:

a) For delivery of liquefied natural gas to the LEASED PROPERTY, during times consistent with the STATION's normal operating procedures; the LESSEE or its agents or contractors shall use the route designated by the STATION for access, shall check in at the security check point and shall provide sufficient proof of insurance as required by Article #5. of the General Lease Part 1. and Article C. above, and shall provide adequate vehicular licensing and identification as required by the STATION for the purpose of coordinating access to the FACILITY; and

b) For the ability to construct, install, operate, preserve, protect, repair and replace the FACILITY; including the ability to inspect, reconstruct, remove, repair, improve, or relocate the FACILITY once installed, subject to the requirements of Article B. (2) above; the LESSEE or its agents or contractors shall have access through the route to be designated by the STATION, provided that the LESSEE shall coordinate any scheduled work in advance with the STATION so as to not unduly interfere with STATION operations; the Lessee or its agents or contractors shall check in at the security check point and shall provide sufficient proof of insurance as required by Article #5. of the Lease Part 1. and Article C. above, and shall provide adequate vehicular licensing and identification as required by the STATION for the purpose of coordinating access to the LEASED PROPERTY.

c) LESSEE may need to make specific arrangements for ingress and egress with STATION from time to time during periods of limited access or heightened security.

(2) For the purpose of exercising the rights granted herein, and subject to all other terms and conditions expressed in this Lease; the LESSEE may review all plans for construction or repair work performed by the GOVERNMENT or its contractors within the LEASED PROPERTY or covered under this Article, for existing or future Easements or Right of Ways within or immediately adjacent to the LEASED PROPERTY and may request such modification of such plans as the LESSEE demonstrates that such activity may adversely affect the operation of the FACILITY. The LESSEE may request such safety measures during construction as are reasonable for the safe operation and physical integrity of the FACILITY. The GOVERNMENT shall consider any such requests for modification to plans or implementation of safety measures. The LESSEE shall provide for access to the LEASED PROPERTY to allow construction or repair work within the LEASED PROPERTY under the pre-approved plans.

(3) The GOVERNMENT reserves the right, to enter and perform work within the LEASED PROPERTY for the purpose of performing any site inspection or work related to environmental compliance and remediation; to inspect, survey, establish, construct, maintain, repair, abandon or replace any existing or future easements or rights of way in or adjacent to the LEASED PROPERTY; or to inspect, survey and maintain the waterfront area, including, but not limited to, cleanup and restoration of contaminated surface or sub-surface material, construction, repairs or replacement of nearby bulkheading and related supporting structures such as

nearby piers or other structures or physical improvements; Provided that such work is performed in accordance with plans and specifications approved under this Article.

Nothing in this Article or the Lease may impede the environmentally related remediation or cleanup responsibilities of the GOVERNMENT under existing or future agreements, regulatory or statutory requirements.

E. SUBJECTION TO EXISTING AND FUTURE EASEMENTS AND RIGHTS OF WAY

This Lease is subject to all outstanding easements and rights of way for location of any type of facility over, across, in and upon the LEASED PROPERTY, or any portion thereof, and to the right of the GOVERNMENT to grant such additional easements and rights of way over, across, in and upon the LEASED PROPERTY as it shall determine to be in the public interest, but which shall be subject to the LESSEE rights; Provided, that any such additional easement or right of way shall be conditioned on the assumption by the Grantee thereof of liability to LESSEE for such damages as LESSEE shall suffer for property destroyed or property rendered unusable on account of Grantee's exercise of its rights thereunder. There is hereby reserved to the holders of such easements and rights of way as are presently outstanding or which may hereafter be granted, to any workers officially engaged in the construction, installation, maintenance, operation, repair, or replacement of facilities located thereon, and to any Federal, State or local official engaged in the official inspection thereof, such reasonable rights of ingress and egress over the LEASED PROPERTY as shall be necessary for the performance of their duties with regard to such facilities.

F. TERMINATION BY GOVERNMENT

(1) The GOVERNMENT may Terminate for Cause the Lease, in whole or in part, upon thirty (30) days written notice of Termination for Cause, and upon Failure (Breach) by the LESSEE to comply with any material term or condition of the Lease, which failure is not cured by the LESSEE within 30 days after receipt from the GOVERNMENT of written notice identifying such failure (Breach), or in the event such failure cannot reasonably be cured within such 30 day period, then the LESSEE fails to undertake such cure promptly after receipt of written notice from the GOVERNMENT identifying such failure or, having undertaken steps to effect such cure, the LESSEE fails to pursue the cure thereof with all reasonable dispatch.

(2) In the event that the GOVERNMENT shall elect to terminate this Lease for Cause on account of the breach of any of the terms and conditions hereof by LESSEE, no adjustment in advance rentals, or in-kind consideration paid by LESSEE shall be made, and the GOVERNMENT shall be entitled to recover and LESSEE shall pay to the GOVERNMENT:

a) The costs incurred in resuming possession of the LEASED PROPERTY.

b) The costs incurred in performing any obligation on the part of LESSEE to be performed hereunder.

c) An amount equal to the aggregate of all unpaid rents obligations and charges that have accrued or become due and payable under this Lease.

(3) If at any future time, the Secretary of the Navy, or if delegated, the Designated Local Representative, determines that the LESSEE's use of the LEASED PROPERTY, or any portion thereof, materially interferes with GOVERNMENT activities, it shall have, upon ninety (90) days written notice, the right to terminate for Convenience this Lease, in whole or in part, to the extent necessary to eliminate such interference; provided that, unless the Secretary of the Navy, or if delegated, the Designated Local Representative, shall have determined that relocation is not feasible, it shall grant to the LESSEE, without charge, a substitute Lease permitting the LESSEE to relocate the FACILITY, or portion thereof, on adjacent GOVERNMENT property, if available. The LESSEE, at its sole expense, shall relocate any portion of the FACILITY constructed or installed by the LESSEE for its purposes, as necessary to utilize the substitute Lease. The substitute Lease shall contain the same terms and conditions as those of this Lease, and shall bear the same expiration date.

In the event of termination for any reason not involving a failure to comply with the terms of the Lease or breach by Lessee, and the GOVERNMENT has determination that the grant of a substitute Lease is not feasible, the GOVERNMENT shall make an equitable adjustment of any advance rentals, whether cash or in kind, paid by LESSEE hereunder.

G. TERMINATION BY LESSEE

LESSEE shall have the right to terminate this Lease upon ninety (90) days written notice to the Local Government Representative in the event of an inability to distribute natural gas to customers, or in the event of damage to or destruction of the improvements on the LEASED PROPERTY or such a substantial portion thereof as to render the LEASED PROPERTY incapable of use for the purposes for which it is Leased hereunder; Provided,

(1) The Local Government Representative either has not authorized or directed the reasonable repair, rebuilding or replacement of the improvements or has made no provision for reasonable payment for such repair, rebuilding or replacement by application of insurance proceeds or otherwise, and

(2) That such inability to distribute, damage or destruction was not occasioned by the fault or negligence of LESSEE or any of its officers, agents, servants, employees, subtenants, licensees or invitees, or by any failure or refusal on the part of LESSEE to fully perform its obligations under this Lease.

H. REPRESENTATIONS

LESSEE has examined, knows and accepts the condition and state of repair of the LEASED PROPERTY and the Station of which it forms a part, and acknowledges that the GOVERNMENT has made no representation concerning such condition and state of repair, nor any agreement or promise to alter, improve, adapt, repair or keep in repair the same, or any item thereof, which has not been fully set forth in this Lease which contains all the agreements made and entered into between the LESSEE and the GOVERNMENT.

Not withstanding anything in the forgoing, the GOVERNMENT and LESSEE agree that the LESSEE shall have no responsibility for the existing environmental conditions or responsibilities of the STATION as set forth within the Environmental Baseline Study, Finding Of Suitability To Lease or Federal Facilities Agreement as referenced under Article #6. of the General Lease, Part 1.

I. INSTALLATION OF IMPROVEMENTS

(1) All work performed by the LESSEE or its agents or contractors in connection with the FACILITY on or in the vicinity of the LEASED PROPERTY shall be done without cost or expense to the GOVERNMENT and in accordance with plans previously approved in writing by the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command or a designated local representative, prior to the construction of any improvements or the making of any substantial alterations, additions or betterments to the Leased premises. The Facility and its improvements may include permanent buildings, sidewalks, roadways, utility lines, trees and shrubbery as approved.

J. UTILITIES AND SERVICES

The LESSEE will contract in the LESSEE's own name and pay for all services and utilities required by the LESSEE. In the event it is not practical for the LESSEE to contract for such services and utilities directly, the GOVERNMENT will require that the LESSEE be responsible for installing a meter at a location identified by the GOVERNMENT. The LESSEE shall be responsible for the cost of the meter installation and removal. The LESSEE will then be required to reimburse the GOVERNMENT for such utilities and services in accordance with this General Provision of the Lease.

In the event that the GOVERNMENT shall furnish LESSEE with any utilities and services maintained by the GOVERNMENT which LESSEE may require in connection with its use of the Leased Property, LESSEE shall pay the GOVERNMENT the charges therefore in addition to the Cash Rent, or In-kind Consideration required under this lease. Such charges and the method of payment thereof shall be determined by the appropriate supplier of such service, in accordance with applicable laws and regulations, on such basis as the appropriate supplier of such service may establish, which may include a requirement for the installation of adequate connecting and metering equipment at the sole cost and expense of LESSEE. It is expressly agreed and understood that the GOVERNMENT in no way warrants the continued maintenance or adequacy of any utilities or services furnished by it to LESSEE.

K. REMOVAL AND RESTORATION OF LEASED PROPERTY

Upon the expiration of this Lease or its prior termination, or any portion thereof, the GOVERNMENT shall have the option either to require the LESSEE, at its sole expense, to remove the above-ground improvements installed or constructed hereunder and restore, in whole or in part to the extent requested by the GOVERNMENT, provided such restoration shall be done in a manner satisfactory to the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command and a designated local STATION environmental representative; and to restore the LEASED PROPERTY and each item thereof to the condition in which it was received, as set forth in the "Exhibit C" Condition Report incorporated by Article #1 of the General Lease, Part 1 hereof, or to such improved condition as may have resulted from any improvement made therein by the GOVERNMENT or by LESSEE during the Lease term, subject however, to ordinary wear and tear and loss or damage for which LESSEE is not liable hereunder; Provided, in the event the GOVERNMENT shall terminate this Lease upon less than ninety (90) days notice LESSEE shall have ninety (90) days from receipt of notice of termination to accomplish such restoration. Upon termination, the LESSEE, at its sole expense, shall close, render inert and cap the pipeline in compliance with then-existing applicable laws and regulations.

All property not so removed shall be deemed abandoned by LESSEE and may be used or disposed of by the GOVERNMENT in any manner whatsoever without any liability to account to LESSEE therefore, but such abandonment shall in no way reduce any obligation of LESSEE for restoration.

L. SURRENDER

Upon the expiration of this Lease or its prior termination, LESSEE shall quietly and peacefully remove itself and its property from the LEASED PROPERTY and surrender the possession thereof to the GOVERNMENT; Provided, in the event the GOVERNMENT shall terminate this Lease upon less than ninety (90) days notice, LESSEE shall be allowed a reasonable period of time, as determined by the Local Government Representative, but in no event to exceed ninety (90) days from receipt of notice of termination, in which to remove all of its property from and terminate its operations on the LEASED PROPERTY. During such period prior to surrender, all obligations assumed by LESSEE under this Lease shall remain in full force and effect; Provided, however, that if the Local Government Representative shall, in his sole discretion, determine that such action is equitable under the circumstances, he may suspend, in whole or in part, any further accruals of Rent or In-kind Consideration between the date of termination of the Lease and the date of final surrender of the LEASED PROPERTY.

M. INDEMNIFICATION BY LESSEE--GOVERNMENT NON-LIABILITY

(1) The LESSEE shall indemnify and hold harmless the GOVERNMENT, its officers, agents and employees for and from any and all costs, expenses, claims, fines, penalties or monetary obligations of any kind incurred by the LESSEE or to any property owned by or in the custody of LESSEE, its officers, agents, servants, employees, subtenants, licensees, or invitees, or for the death of or injury to any of the same which may arise out of or be attributable to the condition, construction, operation, maintenance or state of repair of the LESSEE's personal property or the FACILITY; or in any way caused by the Lessee, its agents or contractors in connection with the LESSEE'S use of or operations on the LEASED PROPERTY or the STATION under this Lease giving rise to GOVERNMENT liability or responsibility. The obligation to indemnify and hold harmless includes, but is not limited to, all environmental suits, claims, and enforcement actions, whether arising during the LESSEE's construction on or use of the property, or after such use has ended and including any GOVERNMENT liability or responsibility for Remedial Action (as defined in Article AD. below) under Federal, State or local environmental laws.

(2) In addition, the LESSEE shall reimburse the GOVERNMENT for all expenditures incurred if: the GOVERNMENT provides LESSEE written demand for action under this Article, and LESSEE fails to undertake such action within a reasonable period of time following the written demand; the GOVERNMENT voluntarily chooses to take any action in response to the LESSEE's failure to fulfill any of the obligations established in this LEASE; the GOVERNMENT is required under applicable law or is directed by any regulatory authority to take any action because of an act or omission of the LESSEE or its agents or contractors; or the GOVERNMENT provides any service to the LESSEE or its agents or

contractors. This provision shall survive the expiration or termination of this Lease, and the LESSEE's obligations hereunder shall apply whenever the GOVERNMENT incurs costs or liabilities resulting from the acts or omissions of the LESSEE, its agents or contractors.

(3) The GOVERNMENT shall not hold liable the LESSEE, its officers, agents and employees for and from any and all costs, expenses, claims, penalties or monetary obligations of any kind in connection with use of the LEASED PROPERTY occurring prior to the date of this Lease, including without limitation all Contamination, Release, or Violation of Applicable Environmental Laws (as such terms are defined in Article AD. below). This clause is not intended to foreclose the LESSEE's right for remedies or defenses against third parties.

a) The GOVERNMENT has provided to LESSEE and the LESSEE acknowledges receipt of the Environmental Baseline Survey and the Finding Of Suitability To Lease for the LEASED PROPERTY.

b) The GOVERNMENT has provided to LESSEE and the LESSEE acknowledges receipt of a copy of the Federal Facilities Agreement (FFA) between the Federal Environmental Protection Agency, the State of Rhode Island Department of Environmental Management and the Department of the Navy. This FFA document provides specific rights, obligations and responsibilities upon the Department of the Navy and other parties. These rights obligations and responsibilities are of a superior interest to the rights contained in this Lease and may impact the use of the LEASED PROPERTY or other areas of STATION land by the LESSEE. No clause or condition of this Lease can be construed as limiting the Department of the Navy or GOVERNMENT'S rights, obligations or responsibilities under the FFA document.

c) Any historic contamination on the LEASED PROPERTY or immediately adjacent STATION property, that being in existence on the LEASED PROPERTY or on immediately adjacent STATION property prior to the date of this Lease which requires remediation shall be the GOVERNMENT'S and not the LESSEE's responsibility. This GOVERNMENT responsibility includes any historic contamination existing on the LEASED PROPERTY at any time as a result of naturally-occurring subsurface migration of any historic contamination from adjacent STATION property.

(4) Not withstanding anything in the forgoing, the GOVERNMENT and LESSEE agree that the LESSEE shall have no responsibility for the existing environmental conditions or responsibilities of the STATION existing prior to the date of this Lease as set forth within the Environmental Baseline Study, Finding Of Suitability To Lease or Federal Facilities Agreement as referenced under Article #6. of the General Lease, Part 1. In no event shall the LESSEE indemnify the GOVERNMENT or a third party for any loss, cost, damages, claims or expenses arising from the GOVERNMENT's own actions or inactions including without limitation the GOVERNMENT's negligence or willful or wanton conduct.

N. IMMINENT THREAT PROTOCOL

(1) In the event the LESSEE or its agents or contractors discovers an environmental condition that poses an imminent threat to human health or the environment either on the LEASED PROPERTY or on other STATION land, the LESSEE shall immediately notify the GOVERNMENT, providing all relevant facts and circumstances by telephone call to:

During (Regular Business hours):
Primary:
Director, Environmental Department
Bldg. 1.
Naval Station Newport
Newport, Rhode Island 02841-1711
Phone - (401) [redacted]

Alternate:
Commanding Officer
Bldg. 690.
Naval Station Newport
Newport, Rhode Island 02841-1522
Phone - (401) [redacted]

During Non-Business Hours: (*24 hour number)
Command Duty Officer
Naval Station Newport
Newport, Rhode Island 02841-1522
Phone - (401) [redacted]

Or, to such numbers and addresses that the GOVERNMENT may specify in writing to LESSEE at a later date.

(2) The GOVERNMENT, upon receipt of the notification described in this Article, shall ensure that the appropriate GOVERNMENT representative(s) is

sent to the location of the discovery as soon as possible and shall, upon accumulation of all relevant information, determine whether any further action by the GOVERNMENT is needed.

The GOVERNMENT may request from the LESSEE or its agents or contractors a detailed written description of the facts and circumstances within a time period specified by the GOVERNMENT.

(3) In the event the GOVERNMENT determines that an environmental condition poses an imminent threat to human health or the environment, the GOVERNMENT may direct the LESSEE, its agents or contractors to vacate the PREMISES until it is safe to return.

(4) For the purpose of this Article only, the term "environmental condition" means any hazardous substance, pollutant or contaminant, including hazardous waste or hazardous constituent, petroleum or petroleum derivative disposed of, released or existing in environmental media such as soil, subsurface soil, air, groundwater, surface water or subsurface geological formations at levels above background, but excludes:

a) Any condition which is disclosed in the Environmental Baseline Survey, Federal Facilities Agreement or the Finding Of Suitability To Lease;
b) Lead Based Paint;
c) Asbestos; and
d) Radon.

(5) For the purpose of this Article only, the term "removal" shall have the same meaning as that term is defined in 42 U.S.C. §9601(23).

(6) Nothing contained in this Article shall alter, limit or change any obligation of the LESSEE or its agents or contractors to comply with all federal, state and local laws including, but not limited to, 42 U.S.C. § 9603 reporting requirements. The LESSEE shall provide all information requested by the GOVERNMENT regarding such actions.

O. LIENS

LESSEE shall promptly discharge or cause to be discharged any valid lien, claim or demand of any kind, except one in favor of the GOVERNMENT, which at any time may arise or exist with respect to LESSEE's use or occupancy of the LEASED PROPERTY or materials or equipment furnished therefore, or any part thereof, and if the same shall not be promptly discharged by LESSEE, the GOVERNMENT may discharge, or cause to be discharged, the same at the expense of LESSEE.

P. STATE AND LOCAL TAXES

In the event that as a result of any future Act of Congress, subjecting GOVERNMENT-owned property to taxation, any taxes, assessments or similar charges are imposed by State or local authorities upon the LEASED PROPERTY (other than property taxes levied upon LESSEE's leasehold possessory interest therein), LESSEE shall pay the same when due and payable and this Lease shall be renegotiated so as to accomplish an equitable reduction in the amount of the Rent, or In-kind Consideration or Maximum Amount to be Expended specified in Article #3. of the General Lease, Part 1 hereof, which reduction shall in no event exceed the amount of such taxes, assessments, or similar charges; Provided, in event the parties hereto are unable to agree within ninety (90) days from the date of the imposition of such taxes, assessments, or similar charges, upon a rental, or in-kind consideration which in the opinion of the Local Government Representative constitutes a reasonable return to the GOVERNMENT on the LEASED PROPERTY, the Local Government Representative shall have the right to determine the amount of the rental, or in-kind consideration, which determination shall be binding on LESSEE, subject to appeal as a dispute in accordance with the provisions of Article Q. of this General Provisions, Part 2.

Q. DISPUTES

1.1 This Lease is subject to the Contract Disputes Act of 1978, as amended (41 U.S.C. 601-613) (the Act).

1.2 Except as provided in the Act, all disputes arising under or relating to this Lease shall be resolved under this clause.

1.3 "Claim", as used in this clause, means a written demand or written assertion by the Lessee or the Government seeking, as a matter of right, the payment of money in a sum certain, the adjustment or interpretation of Lease terms, or other relief arising under or relating to this Lease. A claim arising under this Lease, unlike a claim relating to this Lease, is a claim that can be resolved under a Lease clause that provides for the relief sought by the claimant. However, a written demand or written assertion by the Lessee seeking the payment of money exceeding $100,000 is not a claim under the Act until certified as required by subparagraph 1.4(2) below. A voucher, invoice, or other routine request for payment that is not in dispute when submitted is not a claim under the Act. The submission may be converted to a claim under the Act, by complying with the submission and certification requirements of this clause, if it is disputed either as to liability or amount or is not acted upon in a reasonable time.

1.4(l) A claim by the Lessee shall be made in writing and submitted within 6 years after accrual of the claim to the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command, for a written decision. A claim by the Government against the Lessee shall be subject to a written decision by the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command.

1.4(2)(a)The Lessee shall provide the certification specified in subparagraph 1.4(2)(c) of this clause when submitting any claim--

(A) Exceeding $100,000; or

(B) Regardless of the amount claimed, when using--

(1) Arbitration conducted pursuant to 5 U.S.C. 575-580; or

(2) Any other alternative means of dispute resolution (ADR) technique that the agency elects to handle in accordance with the Administrative Dispute Resolution Act (ADRA).

1.4(2)(b) The certification requirement does not apply to issues in controversy that have not been submitted as all or part of a claim.

1.4(2)(c) The certification shall state as follows:

"I certify that the claim is made in good faith; that the supporting data are accurate and complete to the best of my knowledge and belief; that the amount requested accurately reflects the contract adjustment for which the Lessee believes the Government is liable; and that I am duly authorized to certify the claim on behalf of the Lessee."

1.4(3) The certification may be executed by any person duty authorized to bind the Lessee with respect to the claim.

1.5 For Lessee claims of $100,000 or less, the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command, must, if requested in writing by the Lessee, render a decision within 60 days of the request. For Lessee-certified claims over $100,000, the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command, must, within 60 days, decide the claim or notify the Lessee of the date by which the decision shall be made.

1.6 The Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command, decision shall be final unless the Lessee appeals or files a suit as provided in the Act.

1.7 At the time a claim by the Lessee is submitted to the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command or a claim by the Government is presented to the Lessee, the parties, by mutual consent, may agree to use ADR. When using arbitration conducted pursuant to 5 U.S.C. 575-580, or when using any other ADR technique that the agency elects to handle in accordance with the ADRA, any claim, regardless of amount, shall be accompanied by the certification described in paragraph 1.4(2)(c) of this clause, and executed in accordance with paragraph 1.4(3) of this clause.

1.8 The Government shall pay interest on the amount found due and unpaid by the Government from (1) the date the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command receives the claim (properly certified if required), or (2) the date payment otherwise would be due, if that date is later, until the date of payment. With regard to claims having defective certifications, as defined in FAR 33.201, interest shall be paid from the date that the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command initially receives the claim. Simple interest on claims shall be paid at the rate, fixed by the Secretary of the Treasury, as provided in the Act, which is applicable to the period during which the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command receives the claim and then at the rate applicable for each 6-month period as fixed by the Treasury Secretary during the pendency of the claim.

1.9 The Lessee shall proceed diligently with the performance of the Lease, pending, final resolution of any request for relief, claim, appeal, or action arising under the Lease, and comply with any decision of the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command.

R. COVENANT AGAINST CONTINGENT FEES

LESSEE warrants that no person or agency has been employed or retained to solicit or secure this Lease upon an agreement or understanding for a commission, percentage, brokerage or contingent fee, excepting bona fide employees or bona fide established commercial agencies maintained by LESSEE for the purpose of securing business. For breach or violation of this warranty, the GOVERNMENT shall have the right to annul this Lease without liability or in its discretion to require LESSEE to pay, in addition to the rental or consideration, the full amount of such commission, percentage, brokerage, or contingent fee.

S. CONFIDENTIAL INFORMATION

The GOVERNMENT agrees to keep confidential and not to disclose to third parties any such information which is identified by the Lessee as confidential, business sensitive and/or proprietary, except as otherwise required by law.

T. FAILURE OF GOVERNMENT OR LESSEE TO INSIST ON COMPLIANCE

The failure of the GOVERNMENT or LESSEE to insist, in any one or more instances, upon performance of any of the terms, covenants or conditions of this Lease shall not be construed as a waiver or relinquishment of the GOVERNMENT's or LESSEE's right to the future performance of any such terms, covenants or conditions and LESSEE's or GOVERNMENT's obligations in respect to such future performance shall continue in full force and effect.

U. ASSIGNMENT OR SUBLETTING

(1) LESSEE shall not transfer or assign this Lease or any interest therein nor sublet or otherwise make available to any third party or parties any portion of the LEASED PROPERTY or rights therein without the prior written consent of the GOVERNMENT. Under any assignment made, with or without consent, the assignee shall be deemed to have assumed all of the obligations of LESSEE hereunder, but no assignment shall relieve the assignor of any of LESSEE's obligations hereunder except for an extension of the Lease term beginning after such assignment, and then only if the GOVERNMENT shall have consented thereto.

(2) In the event of LESSEE acquisition by or merger with a third party, the Lease shall be deemed assigned to the surviving entity without requiring the written consent of the GOVERNMENT, and upon written statement of the surviving entity of assumption of all Lease obligations to the Local Government Representative identified in the Lease, Part 1, the GOVERNMENT shall prepare a written Lease Modification to effect such assignment. In the event of such assignment, the GOVERNMENT shall have the right to review such clauses, provisions, terms or conditions of the Lease, Part 1, or General Provisions, Part 2 which may be negatively impacted by the assumption, including, but not limited to, insurance requirements, and to require such remedy available under the Lease clauses, terms, conditions and provisions as appropriate to protect the GOVERNMENT's interests as set forth in this Lease. At the GOVERNMENT's option, a Novation Agreement may be required to satisfy the requirements of this Article.

V. ADVERTISEMENT

The LESSEE shall not allow any form of advertisement to be placed on the Leased premises or on any LESSEE-owned attachments thereto. Such prohibited use may be in the form of, but not limited to, cards, signs, or billboards.

W. LABOR PROVISION

(1) Equal Opportunity: During the term of this Lease the LESSEE agrees as follows:

a) The LESSEE shall not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The LESSEE shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to the following: Employment, upgrading, demotion, or transfer, recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The LESSEE agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the GOVERNMENT setting forth the provisions of this non-discrimination clause.

b) The LESSEE shall in all solicitations or advertisements for employees placed by or on behalf of the LESSEE, state that all qualified applicants shall receive consideration for employment without regard to race, color, religion, sex, or national origin.

c) The LESSEE shall send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding a notice to be provided by the government, advising the labor union or worker's representative of the LESSEE's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

d) The LESSEE shall comply with all provisions of Executive Order 11246 of September 24, 1965, as amended by Executive Order 11375 of October 13, 1967, and of the rules, regulations, and relevant orders of the Secretary of Labor.

e) The LESSEE shall furnish all information and reports required by Executive Order 11246 of September 24, 1965, as amended by Executive Order 11375 of October 13, 1967, and by the rules, regulations, and orders of the Secretary of Labor or pursuant thereto, and shall permit access to his books, records, and accounts by the GOVERNMENT and the Secretary of Labor for purposes of investigating to ascertain compliance with such rules, regulations and orders.

f) In the event of the LESSEE's noncompliance with the Equal Opportunity clause of this Lease or with any of said rules, regulations, or orders, this Lease may be canceled, terminated or suspended in whole or in part and the LESSEE may be declared ineligible for further GOVERNMENT contracts in accordance with procedures authorized in Executive Order 11246 of September 24, 1965, as amended by Executive Order 11375 of October 13, 1967, and such other sanctions may be imposed and remedies invoked as provided in Executive Order 11246 of September 24, 1965, as amended by Executive Order 11375 of October 1967, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

g) The LESSEE shall include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to section 204 of Executive Order 11246 of September 24, 1965, as amended by Executive Order 11375 of October 13, 1967, so that such provisions shall be binding upon each sublessee or vendor. The LESSEE shall take such action with respect to any sublessee or purchase order as the GOVERNMENT may direct as a means of enforcing such provisions including sanctions for noncompliance: Provided, however, that in the event the LESSEE becomes involved in, or is threatened with, litigation with sublessee or vendor as a result of such direction by the GOVERNMENT, the LESSEE may request the United States to enter into such litigation to protect the interests of the United States.

(2) Convict Labor: In connection with the performance of work required by this Lease, LESSEE agrees not to employ any person undergoing a sentence of imprisonment at hard labor.

(3) Contract Work Hours Standards Act (40 U.S. Code 327-330): This Lease, to the extent that it is a contract of character specified in the Contract Work Hours Standards Act (40 U.S.C. 327-330) and is not covered by the Walsh-Healy Public Contracts Act (41 U.S.C. 35-45), is subject to the following provisions and exceptions of said Contract Work Hours Standards Act and to all other provisions and exceptions of said law:

a) The LESSEE shall not require or permit any laborer or mechanic in any workweek in which he is employed on any work under this contract to work in excess of 40 hours in such workweek on work subject to the provisions of the Contract Work Hours Standards Act unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all such hours worked in excess of 40 hours in such workweek. The "basic rate of pay," as used in this clause, shall be the amount paid per hour, exclusive of the LESSEE's contribution or cost for fringe benefits and any cash payment made in lieu of providing fringe benefits, or the basic hourly rate contained in the wage determination, whichever is greater.

b) In the event of any violation of the provisions of paragraph a), the LESSEE shall be liable to any affected employee for any amounts due, and to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of paragraph a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed on such work in excess of the standard workweek of 40 hours without payment of the overtime wages required by paragraph a).

X. GOVERNMENT RULES AND REGULATIONS

LESSEE shall comply with such rules and regulations regarding station security, ingress, egress, environmental, safety and sanitation as may be prescribed, from time to time, by the Local Government Representative or by the Commanding Officer of the STATION; Provided the rights of the LESSEE under the terms, conditions and provisions of the General Lease, Part 1 and the General Provisions, Part 2 are not unduly limited by the GOVERNMENT action.

Y. NOTICES

No notice, order, direction, determination, requirement, consent, or approval under this Lease shall be of any effect unless in writing. All notices required under this Lease shall be addressed to LESSEE, or to the Local Government Representative, as may be appropriate, at the addresses thereof specified in this Lease or at such other addresses as may from time to time be agreed upon by the parties hereto.

Z. PAYMENTS

All cash payments to the GOVERNMENT required under this Lease shall be made by check or postal money order made payable to: "U.S. Treasury." In-kind consideration shall be made available in accordance with the terms and conditions contained in paragraph AI.

AA. INTEREST

Notwithstanding any other provision of this Lease, unless paid within thirty (30) days, all amounts that become payable by the LESSEE to the GOVERNMENT under this Lease (net of any applicable tax credit under the Internal Revenue Code) shall bear interest from the date due. (The rate of interest shall be the Current Value of Funds Rate published by the Secretary of the Treasury pursuant to 31 U.S.C. 3717 (Debt Collection Act of 1982).) Amounts shall be due upon the earliest one of:

(1) The date fixed pursuant to this Lease, including demand consequent upon default termination;

(2) The date of transmittal by the GOVERNMENT to the LESSEE of a proposed supplemental agreement to confirm completed negotiations fixing the amount, or

(3) If this Lease provides for revision of prices, the date of written notice to the LESSEE stating the amount of refund payable in connection with a pricing proposal or in connection with a negotiated pricing agreement not confirmed by Lease amendment.

AB. ADMINISTRATION

The Local Government Representative specified as the NAVAL STATION in Article #10. of this Lease Part 1 shall, under the direction of the Commander, Naval Facilities Engineering Command, have complete charge of the administration of this Lease, and shall exercise full supervision and general direction thereof insofar as the interests of the GOVERNMENT are affected.

AC. DAMAGE TO GOVERNMENT PROPERTY

(1) In the event of damage, including damage by contamination or release of contaminants to any GOVERNMENT property inside or outside of the LEASED PROPERTY by the LESSEE, his officers, agents, servants, employees, subtenants, licensees or invitees, the LESSEE, at the election of the GOVERNMENT, shall promptly repair, replace, or make monetary compensation for the repair or replacement of such property to the satisfaction of the GOVERNMENT.

(2) Prior to the operation of the FACILITY, the LESSEE shall provide evidence of compliance with all local, state, and federal environmental laws and regulations. In the event that the LESSEE shall utilize, process or handle any contaminants, hazardous wastes or hazardous substances, notwithstanding the minimum requirements for insurance provided elsewhere in this Lease, the LESSEE shall obtain insurance in an amount

sufficient to cover possible cleanup costs arising from the LESSEE's operation of the FACILITY.

(3) In accordance with 10 U.S.C. 2692, the LESSEE shall not treat, store or dispose of any Toxic or Hazardous Materials on the LEASED PROPERTY. Unless specifically waived or excepted by an action under 10 U.S.C. § 2692, the following constitutes the definitions, limits and use of toxic or hazardous materials:

a) For the purpose of this provision, the term "storage" and "Toxic or Hazardous Materials" are defined as provided in 48 CFR 252.223-7006 and "Toxic or Hazardous Materials" is further defined in Article AD. below.

b) The LESSEE may import and use SCENTINEL TE or its equivalent in portable containers as specifically incident to and necessary for the intended purpose and normal use of the FACILITY for the purposes of providing an odorant to the vaporized natural gas. Remaining odorant and its container shall be removed from the LEASED PROPERTY following each operation. Odorant shall be handled in accordance with all applicable rules and regulations. A maximum of 10 U.S. gallons at a time shall be transported in this manner onto the LEASED PROPERTY.

c) As part of the FACILITY, installed equipment shall contain within a closed heating system a solution that utilizes a 50/50 mix of propylene glycol and water or equivalent. The solution is necessary for the normal operation of the FACILTIY and shall contain a total volume of approximately 1200 gallons.

(4) Not withstanding anything in the forgoing, the GOVERNMENT and LESSEE agree that the LESSEE shall have no responsibility for the existing environmental conditions or responsibilities of the STATION as set forth within the Environmental Baseline Study, Finding Of Suitability To Lease or Federal Facilities Agreement as referenced under Article #6. of the General Lease, Part 1.

AD. ADDITIONAL PROVISIONS RELATING TO TOXIC AND HAZARDOUS MATERIALS

(1) The LESSEE shall provide official notice to the STATION within 24 hours of receiving any complaint, order, directive, claim, citation, or notice by any Governmental authority or any other person or entity with respect to a violation of Applicable Environmental Laws resulting from the acts or omissions of the LESSEE or its agents or contractors on the LEASED PROPERTY or on other STATION land. The GOVERNMENT may request a more detailed written description of the events or circumstances leading to this event within a time specified by the GOVERNMENT.

(2) Without limitation of the foregoing, in response to the acts or omissions of the LESSEE or its agents or contractors on the LEASED PROPERTY or on other STATION land, the GOVERNMENT may, but shall not be obligated to, take any Remedial Action as it deems necessary or advisable to address any Contamination of the LEASED PROPERTY or other STATION land by Toxic or Hazardous Materials by the Lessee, its agents or contractors, or to ensure compliance by any of them with Applicable Environmental Laws. Such action by the GOVERNMENT may only be taken provided that the GOVERNMENT provides LESSEE written demands for action under this Article, and LESSEE fails to undertake such action within a reasonable period of time following the written demand.

(3) At any time, upon prior notice to the Lessee, the GOVERNMENT or its representatives may conduct inspections on the LEASED PROPERTY to assess whether the operations of the LESSEE or its agents or contractors are in compliance with Applicable Environmental Laws. The right of inspection also includes the prompt right of access into the LEASED PROPERTY upon notice to and presence of the LESSEE or its agents or contractors. To assist in this evaluation, the LESSEE shall provide to the GOVERNMENT or its representatives, any and all books, records, or documents in its possession, or in the possession of their agents or contractors, related to the physical operation of the Facility on the LEASED PROPERTY, which the GOVERNMENT or its representatives may examine, copy, or make extracts therefrom; provided such access to LESSEE's books, record or documents shall not include material or information for which the disclosure is prevented by state or federal law.

(4) As may be reasonably appropriate to confirm the Lessee's compliance with Applicable Environmental Laws, the GOVERNMENT may require, upon written demand to LESSEE, that the LESSEE, from time to time, promptly conduct such tests and procedures for the purpose of assessing whether, as a result of LESSEE's operations, the LEASED PROPERTY are in compliance with Applicable Environmental Laws and of having the

LEASED PROPERTY certified to the GOVERNMENT as being in compliance. Such tests and procedures shall be conducted by recognized professionals to be approved by the GOVERNMENT and in a manner that is reasonably satisfactory to the GOVERNMENT. When demanding such tests and procedures, the GOVERNMENT shall work with the LESSEE to establish reasonable timeframes, appropriate parties to perform the required activities, and reasonable schedules for performance. The GOVERNMENT or its representatives may take such actions as it deems necessary to protect human health and the environment.

(5) For the purposes of this Lease, the terms used above are defined as follows:

"Toxic or Hazardous Materials" means any hazardous, harmful, odorous, radioactive, toxic or dangerous waste, substance or material, including, without limitation, asbestos, polychlorinated biphenyls ("PCBs") and petroleum products, and any hazardous or toxic substance, material or waste, or any pollutant or contaminant defined as such in, or for the purposes of, any environmental laws as were, are now or in the future may be in effect. The LESSEE's obligation under this provision shall extend to any and all such Toxic or Hazardous Materials, whether or not such substance was defined, recognized, known, or suspected of being hazardous, toxic, dangerous, or wasteful at the time of any act or omission giving rise to the LESSEE's obligation.

"Contamination" means a level of Toxic or Hazardous Materials in the air, in or on soil, in the surface water, or in the groundwater that exceeds levels allowed by Applicable Environmental Laws.

"Applicable Environmental Laws" means any Federal, State, or local statute, law, ordinance, rule, regulation, or order (whether voluntary or not) that govern the present or prior activities or operations of the LEASED PROPERTY, or the persons carrying out those activities or operations, relating to the environment, natural resources, or human health and safety, including without limitation the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. § 9601 *et seq.*), the Hazardous Material Transportation Act (49 U.S.C. § 1801 *et seq.*), the Resource Conservation and Recovery Act (42 U.S.C. 6901 *et seq.*), the Federal Water Pollution Control Act (33 U.S.C. § 1251 *et seq.*), the Clean Air Act (42 U.S.C. § 7401 *et seq.*), the Toxic Substances Control Act (15 U.S.C. § 2601 *et seq.*), and the Occupational Safety and Health Act (29 U.S.C. § 651 *et seq.*), as such laws have been amended or supplemented previously, now or in the future.

"Release" means any release, spill, emission, leaking, pumping, injection, deposit, disposal, leaching, or migration into the environment, whether accidental or otherwise, resulting from the act or omissions of the LESSEE, its agents or contractors, or by natural conditions.

"Remedial Action" means any investigation or monitoring of the condition of the LEASED PROPERTY or any cleanup, remedial, removal, or restoration work required or performed on the LEASED PROPERTY because of the presence, suspected presence, release, or suspected release of Toxic or Hazardous Materials.

AE. GRATUITIES

(1) The GOVERNMENT, by written notice to the LESSEE, may terminate the rights of the LESSEE under this Lease if it is found, after notice and hearing by the Secretary of the Navy or his duly authorized representative, that gratuities (in the form of entertainment, gifts, or otherwise) were offered or given by the LESSEE, or any agent or representative of the LESSEE, to any officer or employee of the GOVERNMENT with a view toward securing a Lease or securing favorable treatment with respect to the awarding of amendment, or the making of any determination with respect to the performing of such Lease; Provided, that the existence of the facts upon which the Secretary or his duly authorized representative makes such findings shall be in issue and may be reviewed in any competent court. In the event this Lease is so terminated, the GOVERNMENT shall be entitled:

a) To pursue the same remedies against the LESSEE as it could pursue in the event of a breach of the contract by the LESSEE, and

b) As a penalty in addition to damages in an amount (as determined by the Secretary or his duly authorized representative) which shall be not less than three nor more than ten times the cost incurred by the LESSEE in providing such gratuities to any such officer or employee.

(2) The rights and remedies of the GOVERNMENT provided in this clause shall not be exclusive and are in addition to any other rights and remedies provided by law or under this Lease.

AF. RIGHT TO RECORD MEMORANDUM

LESSEE shall have the right to record a memorandum of this Lease setting forth the duration of such Lease and such other basic terms as the GOVERNMENT and the LESSEE shall mutually agree, and the GOVERNMENT and LESSEE shall execute and deliver the memorandum of such Lease in recordable form. LESSEE shall be responsible for any and all costs and/or expenses associated with the preparation, execution and recordation of such memorandum including reimbursement of related GOVERNMENT expenses.

AG. LESSEE'S RIGHT OF ENJOYMENT

The LESSEE'S rights hereunder are subject to such reasonable rules and regulations as may be prescribed by the GOVERNMENT to ensure that the exercise of such rights shall not interfere in a material way with GOVERNMENT activities at the STATION. Such rules and regulations shall not unreasonably reduce, limit, restrict or interfere with the LESSEE's rights, and shall not unreasonably increase the LESSEE's obligations, under the terms and conditions of this General Lease, Part 1. or the General Provisions, Part 2.

Upon paying the rent and all other payments required to be made by LESSEE hereunder, and upon LESSEE's performing and fulfilling all material terms, conditions or agreements on its part to be performed or fulfilled, LESSEE shall quietly have and enjoy the LEASED PROPERTY during the term of the Lease; Provided however, that the right of quiet enjoyment is subject to all the other terms and conditions of this General Lease, Part 1 and General Provisions, Part 2.

AH. FIRST RIGHT OF REFUSAL TO PURCHASE

As provided under 10 U.S.C. § 2667, the LESSEE shall have the first right to buy the property from the GOVERNMENT if the lease is revoked to allow the GOVERNMENT to sell the property under any other provision of law.

AI. IN-KIND CONSIDERATION

(1) The GOVERNMENT and LESSEE may determine that the rental compensation, in whole or in part, paid by LESSEE under the terms and conditions of this Lease shall be paid under an In-Kind payment process.

(2) Said In-Kind payment process shall be in the form of a credited amount held by LESSEE for the benefit of the STATION, against which the STATION may draw value in the form of work, as agreed upon by STATION and LESSEE, to be performed by LESSEE or by LESSEE's Contractors or Agents as approved by the GOVERNMENT. Said Value shall equate to an amount as prior agreed upon by STATION and LESSEE as appropriate to the work requested and performed and shall be applied against (and shall reduce) the amount of credit held available.

(3) Unused portions of the credited amount, if accrued annually or in lump payment, shall not expire but shall be available for future work as agreed upon by STATION and LESSEE. In the event of a credit balance at the expiration or termination of the Lease, or at the request of the GOVERNMENT, the amount remaining shall be paid by the LESSEE to the GOVERNMENT as a cash payment within 30 days of a written notice by the GOVERNMENT under the terms and conditions for cash payment of rents in the General Lease Provisions.

(4) Each payment of rental compensation by in-kind consideration shall be conditioned upon a written agreement between the STATION and LESSEE that outlines the scope of the work to be performed, the value of the work to be performed and other relevant considerations necessary to define the expectations of the parties. The written agreement shall reference this LEASE Contract and shall be forwarded to the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command to be part of the official Lease record.

(5) The nature of the work shall be such that the LESSEE could reasonably be expected to directly perform or contract for the service, equipment or other product to be delivered in the course of the LESSEE's normal business practice. The LESSEE shall not unreasonably withhold, delay or otherwise restrict the GOVERNMENT'S ability to obtain work requested under this Article.

48 MIDTRI GEN 00002-001

UNITED STATES OF AMERICA

G United States of America
E Southern Union Company

GRANT OF EASEMENT

Dated September 13, 2001

Cuddington Highway
Middletown, RI

Coddington Highway

All correspondence pertaining to this
Easement should include reference to
N62470-01-RP-00174
LANTDIV FILE NO. EO-0663
EFANE FILE NO. EO-0150

GRANT OF EASEMENT

THIS INDENTURE, made this 13th day of September, 2001, by and between the UNITED STATES OF AMERICA, acting by and through the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command, under the direction of the Secretary of the Navy, hereinafter called the GOVERNMENT, and Southern Union Company - New England Division d/b/a Providence Gas Company (PROVGAS), hereinafter called the GRANTEE;

W I T N E S S E T H:

WHEREAS, the GOVERNMENT owns that certain real property identified as Naval Station Newport, located in the Town of Middletown, County of Newport, State of Rhode Island, hereinafter called the STATION; and

WHEREAS, the GRANTEE has requested an Easement and associated right of access for the following non-exclusive use: to construct, install, operate, maintain, preserve, protect, repair and replace a natural gas pipeline with associated materials and equipment, which shall be used by the GRANTEE to distribute natural gas to the

48 MIDTRI GEN 00002-0-001

surrounding community and the STATION, on, in, over and under that portion of the STATION hereinafter described; and

WHEREAS, the GOVERNMENT has found that the granting of such Easement on the terms and conditions hereinafter stated is not incompatible with the public interest.

NOW THEREFORE, this indenture witnesseth that, in consideration of **$47,900.00 (Forty-Seven Thousand, Nine Hundred Dollars)** the GOVERNMENT, pursuant to the authority of 10 U.S.C. § 2669, hereby grants to the said GRANTEE, and its successors and assigns, an Easement with term intended to be coextensive with Lease No. N62470-01-RP-00175 (LANTDIV File No. LO-0410; EFANE File No. LO-0019) and is for an initial term of 25 years and unless extended, shall terminate on the 12th day of September, 2026. If Lease No. N62470-01-RP-00175 (LANTDIV File No. LO-0410; EFANE File No. LO-0019) is extended for an additional term of up to 25 years, and fair market value for an easement extension is determined by independent Government appraisal and paid as compensation to the GOVERNMENT, this easement shall likewise be extended and shall terminate at the same date of Lease No. N62470-01-RP-00175 (LANTDIV File No. LO-0410; EFANE File No. LO-0019) but not later than on the 12th day of September, 2051.

Said easement is granted together with the right of access, to construct, install, operate, maintain, preserve, protect, repair and replace a natural gas pipeline with associated materials and equipment, hereinafter called the PIPELINE, on, in, over and under those portions of the STATION hereinafter called the PREMISES, and described as follows:

Certain parcels of land situate, lying and being in the Town of Middletown, County of Newport, State of Rhode Island, which consist of corridors for installation of pipeline, all as shown on a map marked Exhibit "A" entitled "Gas Main Easement and Lease Location for Providence Gas Company located at Newport Naval Base, Newport, R.I.", prepared by American Engineering at a scale of 1"=50' and dated 9/20/2000, updated on 8/7/2001 attached hereto and made a part hereof, identified in three sections as Section I, Section II-A and Section II-B and being bounded and described as follows:

SECTION I:

BEGINNING at a point on the northerly right-of-way line of Coddington Highway, said point being forty and 00/100 (40.00') right of and directly opposite station 24+16.06, as shown by the State of Rhode Island Highway Plat No. 707, said point also being 2,513 feet (more or less) to the southeasterly corner of Navy Parcel A-10, said point also being the southeasterly corner of Section I; and identified as the TRUE POINT OF BEGINNING of SECTION I;

Thence along the northerly right-of-way line of said Coddington Highway, North 68°-55'-54" West, twenty and 20/100 feet (20.20') to the southwesterly corner of said Section I,

Thence leaving said right-of-way line, North 12°-58'-20" East, thirty-one and 33/100 feet (31.33') to a point,

Thence North 01°-09'-44" West, thirty-nine and 26/100 feet (39.26') to a point;

Thence North 05°-07'-23" East, two hundred twenty-one and 79/100 feet (221.79') to a point;

Thence North 11°-14'-43" East, eighty-one and 81/100 feet (81.81') to a point;

Thence North 21°-10'-47" East, eighty-six and 06/100 feet (86.06') to a point;

Thence North 04°-46'-18" East, seven hundred seventeen and 26/100 feet (717.26') to a point;

Thence North 53°-30'-17" East, forty-six and 32/100 feet (46.32') to a point;

Thence North 04°-59'-54" East, one hundred seventy-seven and 29/100 feet (177.29') to a point, said point being the northeasterly corner of Section II-A, said point also being the northwesterly corner of said Section I;

Thence South 85°-45'-12" East, twenty and 00/100 feet (20.00') to a point, said point also being the northeasterly corner of said Section I;

Thence South 04°-59'-54" West, one hundred eighty-six and 56/100 feet (186.56') to a point;

Thence South 53°-30'-17" West, forty-six and 28/100 feet (46.28') to a point;

Thence South 04°-46'-18" West, seven hundred eleven and 09/100 feet (711.09') to a point;

Thence South 21°-10'-47" West, eighty-seven and 21/100 feet (87.21') to a point;

Thence South 11°-14'-43" West, seventy-nine and 01/100 feet (79.01') to a point;

Thence South 05°-07'-23" West, two hundred nineteen and 62/100 feet (219.62') to a point;

Thence South 01°-09'-44" East, forty and 64/100 feet (40.64') to a point;

Thence South 12°-58'-20" West, thirty-six and 65/100 feet (36.65') returning to the TRUE POINT OF BEGINNING of SECTION I.

Said parcel contains 28,017.6 square feet, more or less.

Meaning and intending to describe that parcel of land being a twenty and 00/100 (20.00') wide gas Easement, denoted as Section I, as shown on that plan entitled "Gas Main Easement Location for Providence Gas Company located at Newport Naval Base, Newport, R.I." Prepared by American Engineering at a scale of 1"=50' and dated 9/20/2000.

SECTION II-A:

Commencing at a point on the northerly right-of-way line of Coddington Highway, said point being forty and 00/100 (40.00') right of and directly opposite station 24+16.06, as shown by the State of Rhode Island Highway Plat No. 707, said point also being 2,513 feet (more or less) to the southeasterly corner of Navy Parcel A-10, said point also being the southeasterly corner of Section I;

Thence along the northerly right-of-way line of said Coddington Highway, North 68°-55'-54" West, twenty and 20/100 feet (20.20') to the southwesterly corner of said Section I,

Thence leaving said right-of-way line, North 12°-58'-20" East, thirty-one and 33/100 feet (31.33') to a point,

Thence North 01°-09'-44" West, thirty-nine and 26/100 feet (39.26') to a point;

Thence North 05°-07'-23" East, two hundred twenty-one and 79/100 feet (221.79') to a point;

Thence North 11°-14'-43" East, eighty-one and 81/100 feet (81.81') to a point;

Thence North 21°-10'-47" East, eighty-six and 06/100 feet (86.06') to a point;

Thence North 04°-46'-18" East, seven hundred seventeen and 26/100 feet (717.26') to a point;

Thence North 53°-30'-17" East, forty-six and 32/100 feet (46.32') to a point;

Thence North 04°-59'-54" East, one hundred seventy-seven and 29/100 feet (177.29') to a point, said point being the northeasterly corner of said Section II-A, said point also being the northwesterly corner of said Section I, said point being the TRUE POINT OF BEGINNING of SECTION II-A;

Thence South 04°-59'-54" West, twenty and 00/100 feet (20.00'), bounded easterly by said Section I to a point, said point also being the southeasterly corner of said Section II-A;

Thence North 85°-45'-12" West, two hundred twenty-two and 98/100 feet (222.98') to a point;

Thence North 68°-52'-25" West, seventeen and 81/100 feet (17.81') to a point at land now or formerly owned by the State of Rhode Island, said point being thirty-five and 25/100 feet (35.25') left of and directly opposite the baseline Station 867+28.06;

Thence running along the arc of a curve to the left having a radius of one thousand nine hundred and forty-five and 33/100 feet (1945.33'), a chord length of twenty and 37/100 feet (20.37') and a chord bearing of North 32°-03'-48" East to a point thirty-five and 25/100 feet (35.25') left of and directly opposite the baseline Station 867+08.06;

Thence leaving said curve, South 68°-52'-25" East, ten and 98/100 feet (10.98') to a point;

Thence South 85°-45'-12" East, two hundred twenty and 27/100 feet (220.27') returning to the TRUE POINT OF BEGINNING of SECTION II-A.

Said parcel contains 4,718.5 square feet, more or less.

Meaning and intending to describe that parcel of land being a twenty and 00/100 (20.00') wide gas Easement, denoted as Section II-A, as shown on that plan entitled "Gas Main Easement Location for Providence Gas Company located at Newport Naval Base, Newport, R.I." Prepared by American Engineering at a scale of 1"=50' and dated 9/20/2000.

SECTION II-B:

Commencing at a point on the northerly right-of-way line of Coddington Highway, said point being forty and 00/100 (40.00') right of and directly opposite station 24+16.06, as shown by the State of Rhode Island Highway Plat No. 707, said point also being 2,513 feet (more or less) to the southeasterly corner of Navy Parcel A-10, said point also being the southeasterly corner of Section I;

Thence along the northerly right-of-way line of said Coddington Highway, North 68°-55'-54" West, twenty and 20/100 feet (20.20') to the southwesterly corner of said Section I,

Thence leaving said right-of-way line, North 12°-58'-20" East, thirty-one and 33/100 feet (31.33') to a point,

Thence North 01°-09'-44" West, thirty-nine and 26/100 feet (39.26') to a point;

Thence North 05°-07'-23" East, two hundred twenty-one and 79/100 feet (221.79') to a point;

Thence North 11°-14'-43" East, eighty-one and 81/100 feet (81.81') to a point;

Thence North 21°-10'-47" East, eighty-six and 06/100 feet (86.06') to a point;

Thence North 04°-46'-18" East, seven hundred seventeen and 26/100 feet (717.26') to a point;

Thence North 53°-30'-17" East, forty-six and 32/100 feet (46.32') to a point;

Thence North 04°-59'-54" East, one hundred seventy-seven and 29/100 feet (177.29') to a point, said point being the northeasterly corner of said Section II-A, said point also being the northwesterly corner of said Section I;

Thence North 85°-45'-12" West, two hundred twenty and 27/100 feet (220.27') to the a point;

Thence North 68°-52'-25" West, ten and 98/100 feet (10.98') to a point at land now or formerly owned by the State of Rhode Island, said point being thirty-five and 25/100 feet (35.25') left of and directly opposite the baseline Station 867+08.06;

Thence continuing North 68°-52'-25" West, eighty-four and 01/100 feet (84.01') across said land now or formerly owned by the State of Rhode Island, said point being forty-seven and 25/100 feet (47.25') right of and directly opposite the baseline Station 867+23.96, said point also being the northeasterly corner of Section II-B, said point also being the TRUE POINT OF BEGINNING of SECTION II-B;

Thence running along the arc of a curve to the right having a radius of one thousand eight hundred and sixty-two and 83/100 feet (1862.83'), a chord length of twenty and 40/100 feet (20.40') and a chord bearing of South 32°-03'-48" West to a point being forty-seven and 25/100 feet (47.25') right of and directly opposite the baseline Station 867+23.96;

Thence leaving said curve, North 68°-52'-25" West, eighty-six and 63/100 feet (86.63') to a point on the southeasterly line of SECTION III (as leased under N62470-01-RP-00175/LO-0410), said point also being the southwesterly corner of said Section II-B;

Thence northeasterly along said southeasterly line of SECTION III (as leased under N62470-01-RP-00175/LO-0410), North 34°-58'-11" East, one hundred eighty-seven and 25/100 feet (187.25') to a point, said point also being the northwesterly corner of said Section II-B;

Thence leaving said southeasterly line, South 55°-01'-49" East, twenty and 00/100 feet (20.00') to a point;

Thence southwesterly along a line south east of and parallel with said southeasterly line of SECTION III (as leased under N62470-01-RP-00175/LO-0410), South 34°-58'-11" West, one hundred sixty-one and 72/100 feet (161.72') to a point;

Thence South 68°-52'-25" East, sixty-five and 14/100 feet (65.14') returning to the TRUE POINT OF BEGINNING of SECTION II-B;

Said parcel contains 5,006.0 square feet, more or less.

Meaning and intending to describe that parcel of land being a twenty and 00/100 (20.00') wide gas Easement, denoted as Section II-B, as shown on that plan entitled "Gas Main Easement and Lease Location for Providence Gas Company located at Newport Naval Base, Newport, R.I." Prepared by American Engineering at a scale of 1"=50' and dated 9/20/2000, updated on 8/7/2001.

SUBJECT ONLY TO all existing Easements and any other outstanding or superior rights to use the Premises currently of record in the Land Evidence Records for the Town of Middletown or in Department of Navy records, and to the GOVERNMENT'S right to continue the operation of any utility lines as may be currently located on, over, across or under the PREMISES including but not limited to lines which are evidenced by notation on Exhibit "A", but otherwise exclusively reserved for the use by the GRANTEE as permitted herein.

THIS EASEMENT is granted subject to the following additional terms and conditions:

1. All work performed by the GRANTEE or its agents or contractors in connection with the PIPELINE on or in the vicinity of the PREMISES shall be done without cost or expense to the GOVERNMENT and in accordance with plans previously approved in writing by the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command or a designated local representative. The GRANTEE, its agents and contractors shall assume liability caused by their acts or omissions incident to their ingress, egress and use of PREMISES for the loss of, or damage to real property, and for third party bodily injury and property damage; and shall maintain a commercial insurance policy in effect sufficient to cover common business risks associated with operations on the PREMISES. The GOVERNMENT will determine the sufficiency of coverage and review the terms of insurance every five years. The GRANTEE, its agents and contractors shall provide such evidence as necessary to demonstrate satisfaction of this requirement.

2. The GRANTEE, at its own cost and expense, shall protect, preserve, maintain and keep in good order the PREMISES. Any property of the United States damaged or destroyed by the GRANTEE incident to the use and occupation of the PREMISES,

including property on STATION land used for ingress and egress, reasonable wear and tear excepted, shall be promptly repaired, replaced, or relocated by the GRANTEE to the reasonable satisfaction of and in accordance with plans and specifications previously approved in writing by Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command or a designated local representative.

3. The GRANTEE may undertake all or part of the PIPELINE operations on the PREMISES or fulfill other terms of this Easement through agents or contractors; however, the GRANTEE shall be solely responsible for compliance with all requirements established in this Easement. The GOVERNMENT may seek any recourse as may be allowed by applicable law against the GRANTEE for the acts or omissions of the GRANTEE's agents or contractors that are not consistent with the terms of this Easement.

4. All equipment and improvements constructed for the PIPELINE on the PREMISES by the GRANTEE hereunder shall remain the property of the GRANTEE. The GRANTEE shall have the right to inspect, reconstruct, remove, repair, replace, improve, relocate its property on the PREMISES, and make such changes, alterations, substitutions, replacements, additions to or extensions of its PIPELINE subject to the limitations of statute or regulation and

as set forth in this Easement, including but not limited to the following:

A. Any and all improvements, repairs, improvements, relocations, reconstruction, changes, alterations, substitutions, replacements, additions to or extensions of the PIPELINE; provided however that any of the foregoing actions which would result in an increase in capacity of the PIPELINE beyond its original design level (whether performed by the GRANTEE or its agents or contractors in connection with the PIPELINE) is expressly prohibited without the prior written consent of the GOVERNMENT.

B. There shall be no permanent storage of explosive or flammable or hazardous wastes and material, such as gas, liquid or otherwise, on the PREMISES.

5. For the purpose of exercising the rights granted herein, the GRANTEE or its agents or contractors shall have the right of ingress and egress to the PREMISES, as follows:

A. For the ability to construct, install, operate, preserve, protect, repair and replace a natural gas pipeline with associated materials and equipment; including the ability to inspect, reconstruct, remove, repair, improve, and relocate the PIPELINE once installed; the GRANTEE or its agents or contractors shall have access through the route to be designated by the Station during times consistent with the STATION normal operating procedures, provided that the Grantee shall coordinate any scheduled work in advance with the Station so as to not unduly interfere with STATION operations; the Grantee or its agents or contractors shall check in at the security check point and shall provide sufficient proof of insurance, adequate vehicular licensing and identification as required by the STATION for the purpose of coordinating access to the PREMISES.

B. GRANTEE may need to make specific arrangements for ingress and egress with STATION from time to time during periods of limited access or heightened security.

6. For the purpose of exercising the rights granted herein, and subject to all other terms and conditions expressed in this Easement, the GRANTEE shall have the right to review all plans for construction or repair work performed by the GOVERNMENT or its contractors within the PREMISES or covered under this Article, for existing or future Easements or Right of Ways within or immediately adjacent to the PREMISES and may request such modification of such plans as the GRANTEE demonstrates that such activity may adversely affect the operation of the FACILITY. The GRANTEE may request such safety measures during construction as are reasonable for the safe operation and physical integrity of the FACILITY.

7. The GRANTEE shall indemnify and hold harmless the GOVERNMENT, its officers, agents and employees for and from any and all costs, expenses, claims, fines, penalties or monetary obligations of any kind incurred by the GRANTEE or in any way caused by the GRANTEE, its agents or contractors in connection with the GRANTEE'S use of or operations on the PREMISES or the STATION under this Easement giving rise to GOVERNMENT liability or responsibility. The obligation to indemnify and hold harmless includes, but is not limited to, GOVERNMENT liability or responsibility for Remedial Action (as defined in Article 8. of this Easement) under Federal, State or local environmental laws. In addition, the GRANTEE shall reimburse the GOVERNMENT for all expenditures incurred if: the GOVERNMENT provides GRANTEE written demands for action under this Article, and GRANTEE fails to undertake such action within a reasonable period of time following the written demand; the GOVERNMENT voluntarily chooses to take any action in response to the GRANTEE's failure to fulfill any of the obligations established in this GRANT OF EASEMENT; the GOVERNMENT is required under applicable law or is directed by any regulatory authority to take any action because of an act or omission of the GRANTEE or its agents or contractors; or the GOVERNMENT provides any service to the GRANTEE or its agents or contractors. This provision shall survive the expiration or termination of this Easement, and the GRANTEE's obligations hereunder shall apply whenever the

GOVERNMENT incurs costs or liabilities resulting from the acts or omissions of the GRANTEE, its agents or contractors.

8. The GOVERNMENT shall not hold liable the GRANTEE, its officers, agents and employees for and from any and all costs, expenses, claims, penalties or monetary obligations of any kind in connection with use of the PREMISES occurring prior to the date of this Easement, including without limitation all Contamination, Release, or Violation of Applicable Environmental Laws (as such terms are defined in Article 10. of this Easement). This clause is not intended to foreclose the GRANTEE's right for remedies or defenses against third parties.

A. The GOVERNMENT has provided to GRANTEE and the GRANTEE acknowledges receipt of the Environmental Baseline Survey and the Finding of Suitability for the PREMISES.

B. The GOVERNMENT has provided to GRANTEE and the GRANTEE acknowledges receipt of a copy of the Federal Facilities Agreement (FFA) between the Federal Environmental Protection Agency, the State of Rhode Island Department of Environmental Management and the Department of the Navy. This FFA document provides specific rights, obligations and responsibilities upon the Department of the Navy and other parties. These rights obligations and responsibilities are of a superior interest to the rights contained in this Easement and may impact the use of the PREMISES or other areas of STATION land by the GRANTEE. No clause or condition of this Easement can be construed as limiting the Department of the Navy or GOVERNMENT'S rights, obligations or responsibilities under the FFA document.

C. Any historic contamination on the PREMISES or immediately adjacent STATION property, that being in existence on the PREMISES or on immediately adjacent STATION property prior to the date of this Easement which requires remediation shall be the GOVERNMENT'S and not the GRANTEE's responsibility. This GOVERNMENT responsibility includes any historic contamination existing on the PREMISES at any time as a result of naturally-occurring subsurface migration of any historic contamination from adjacent STATION property.

9. Imminent Threat Protocol. In the event the GRANTEE or its agents or contractors discovers an environmental condition that poses an imminent threat to human health or the environment either on the PREMISES or on other STATION land, the GRANTEE shall immediately notify the GOVERNMENT, providing all relevant facts and circumstances by telephone call to:

During (Regular Business hours):

Primary:
Director, Environmental Department
Bldg. 1.
Naval Station Newport
Newport, Rhode Island 02841-1711
Phone - (401) 841-7671

Alternate:
Commanding Officer
Bldg. 690
Naval Station Newport
Newport, Rhode Island 02841-1522
Phone - (401) 841-3431

or During Non-Business Hours: (*24 hour number)
Command Duty Officer
Naval Station Newport
Newport, Rhode Island 02841-1522
Phone - (401) 841-3456

Or, to such numbers and addresses that the GOVERNMENT may specify in writing to GRANTEE at a later date.

A. The GOVERNMENT, upon receipt of the notification described in this Article, shall ensure that the appropriate GOVERNMENT representative(s) is sent to the location of the discovery as soon as possible and shall, upon accumulation of all relevant information, determine whether any further action by the GOVERNMENT is needed.

The GOVERNMENT may request from the GRANTEE or its agents or contractors a detailed written description of the facts and circumstances within a time period specified by the GOVERNMENT.

B. In the event the GOVERNMENT determines that an environmental condition poses an imminent threat to human health or the environment, the GOVERNMENT may direct the GRANTEE, its agents or contractors to vacate the PREMISES until it is safe to return.

C. For the purpose of this Article 9 only, the term "environmental condition" means any hazardous substance, pollutant or contaminant, including hazardous waste or hazardous constituent, petroleum or petroleum derivative disposed of, released or existing in environmental media such as soil, subsurface soil, air, groundwater, surface water or subsurface geological formations at levels above background, but excludes:

(1) Any condition which is disclosed in the Environmental Baseline Survey, Federal Facilities Agreement or the Finding of Suitability;
(2) Lead Based Paint;
(3) Asbestos; and
(4) Radon.

D. For the purpose of this Article 9. only, the term "removal" shall have the same meaning as that term is defined in 42 U.S.C. § 9601(23).

E. Nothing contained in this Article 9. shall alter, limit or change any obligation of the GRANTEE or its agents or contractors to comply with all federal, state and local laws including, but not limited to, 42 U.S.C. § 9603 reporting requirements. The GRANTEE shall provide all information requested by the GOVERNMENT regarding such actions.

10. The GRANTEE and GOVERNMENT agree to the following additional provisions relating to Toxic or Hazardous Materials.

A. The GRANTEE shall provide official notice to the STATION within 24 hours of receiving any complaint, order, directive, claim, citation, or notice by any Governmental authority or any other person or entity with respect to a violation of Applicable Environmental Laws resulting from the acts or omissions of the GRANTEE or its agents or contractors on the PREMISES or on other STATION land. The GOVERNMENT may request a more detailed written description of the events or circumstances leading to this event within a time specified by the GOVERNMENT.

B. Without limitation of the foregoing, in response to the acts or omissions of the GRANTEE or its agents or contractors on the PREMISES or on other STATION land, the GOVERNMENT may, but shall not be obligated to, take any Remedial Action as it deems necessary or advisable to address any Contamination of the PREMISES or other STATION land by Toxic or Hazardous Materials by the Grantee, its agents or contractors, or to ensure compliance by any of them with Applicable Environmental Laws. Such action by the GOVERNMENT may only be taken provided that the GOVERNMENT provides GRANTEE written demands for action under this Article, and GRANTEE fails to undertake such action within a reasonable period of time following the written demand.

C. At any time, upon prior notice to the GRANTEE, the GOVERNMENT or its representatives may conduct inspections on the PREMISES to assess whether the operations of the GRANTEE or its agents or contractors are in compliance with Applicable Environmental Laws. To assist in this evaluation, the GRANTEE shall provide to the GOVERNMENT or its representatives, any and all books, records, or documents in its possession, or in the possession of their agents or contractors, related to the physical operation of the PIPELINE on the PREMISES, which the GOVERNMENT or its representatives may examine, copy, or make extracts therefrom; Provided such access to GRANTEE's books, record or documents shall not include material or information for which the disclosure is prevented by state or federal law.

D. As may be reasonably appropriate to confirm the GRANTEE's compliance with Applicable Environmental Laws, the GOVERNMENT may require, upon written demand to GRANTEE, that the GRANTEE, from time to time, promptly conduct such tests and procedures for the purpose of assessing whether, as a result of GRANTEE's operations, the PREMISES are in compliance with Applicable Environmental Laws and of having the PREMISES certified to the GOVERNMENT as being in compliance. Such tests and procedures shall be conducted by recognized professionals to be approved by the GOVERNMENT and in a manner that is reasonably satisfactory to the GOVERNMENT. When demanding such tests and procedures, the GOVERNMENT shall work with the GRANTEE to establish reasonable timeframes, appropriate parties to perform the required activities, and reasonable schedules for performance. The GOVERNMENT or its representatives may take such action as it deems necessary to protect human health and the environment.

E. For the purposes of this Easement, the terms used above are defined as follows:

"Toxic or Hazardous Materials" means any hazardous, harmful, odorous, radioactive, toxic or dangerous waste, substance or material, including, without limitation, asbestos, polychlorinated biphenyls ("PCBs") and petroleum products, and any hazardous or toxic substance, material or waste, or any pollutant or contaminant defined as such in, or for the purposes of, any environmental laws as were, are now or in the future may be in effect. The GRANTEE's obligation under this provision shall extend to any and all such Toxic or Hazardous Materials, whether or not such substance was defined, recognized, known, or suspected of being hazardous, toxic, dangerous, or wasteful at the time of any act or omission giving rise to the GRANTEE's obligation.

"Contamination" means a level of Toxic or Hazardous Materials in the air, in or on soil, in the surface water, or in the groundwater that exceeds levels allowed by Applicable Environmental Laws.

"Applicable Environmental Laws" means any Federal, State, or local statute, law, ordinance, rule, regulation, or order (whether voluntary or not) that govern the present or prior activities or operations of the PREMISES, or the persons carrying out those activities or operations, relating to the environment, natural resources, or human health and safety, including without limitation the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. § 9601 *et seq.*), the Hazardous Material Transportation Act (49 U.S.C. § 1801 *et seq.*), the Resource Conservation and Recovery Act (42 U.S.C. 6901 *et seq.*), the Federal Water Pollution Control Act (33 U.S.C. § 1251 *et seq.*), the Clean Air Act (42 U.S.C. § 7401 *et seq.*), the Toxic Substances Control Act (15 U.S.C. § 2601 *et seq.*), and the Occupational Safety and Health Act (29 U.S.C. § 651 *et seq.*), as such laws have been amended or supplemented previously, now or in the future.

"Release" means any release, spill, emission, leaking, pumping, injection, deposit, disposal, leaching, or migration into the environment, whether accidental or otherwise, resulting from the act or omissions of the GRANTEE, its agents or contractors, or by natural conditions.

"Remedial Action" means any investigation or monitoring of the condition of the PREMISES or any cleanup, remedial, removal, or restoration work required or performed on the PREMISES because of the presence, suspected presence, release, or suspected release of Toxic or Hazardous Materials.

11. The GRANTEE'S rights hereunder are subject to such reasonable rules and regulations as may be prescribed by the GOVERNMENT to ensure that the exercise of such rights shall not interfere in a material way with GOVERNMENT activities at the STATION. Such rules and regulations shall not unreasonably reduce, limit, restrict or interfere with the GRANTEE 's rights, and shall not unreasonably increase the GRANTEE 's obligations, under the terms and conditions of this Easement.

12. Upon completion of any construction, maintenance or repair efforts for the PIPELINE, the GRANTEE, at its sole expense, shall restore the PREMISES to the same, or as good condition as existed prior to the initiation of such work.

13. The GOVERNMENT agrees to keep confidential and not to disclose to third parties any such information which is identified by the GRANTEE as confidential, business sensitive and/or proprietary, except as otherwise required by law.

14. The GOVERNMENT may terminate this Easement, in whole or in part, upon:

A. Failure by the GRANTEE to comply with any material term or condition of the Easement, which failure is not cured by the GRANTEE within 30 days after receipt from the GOVERNMENT of written notice identifying such failure, or in the event such failure cannot reasonably be cured within such 30 day period, then the GRANTEE fails to undertake such cure promptly after receipt of written notice from the GOVERNMENT identifying such failure or, having undertaken steps to effect such cure, the GRANTEE fails to pursue the cure thereof with all reasonable dispatch; or

B. Abandonment of the rights granted herein by GRANTEE, defined as the unequivocal and decisive acts of the GRANTEE clearly indicating an intent on GRANTEE'S part to relinquish all rights to such Easement; or

C. Nonuse of such rights for a period of twenty-four consecutive months. For the purpose of this Easement, satisfaction of the "use" requirement shall include, without limitation, the GRANTEE'S performance of an annual inspection and such maintenance as sufficient to ensure a safe and operable condition of the PIPELINE, and "nonuse" shall require more than a lack of transferring liquefied natural gas into the PIPELINE.

15. If at any future time, the Secretary of the Navy, or if delegated, the designated local representative, determines that the GRANTEE'S use of the PREMISES, or any portion thereof, materially interferes with GOVERNMENT activities, it shall have, upon ninety (90) days written notice, the right to terminate or relocate this Easement, in whole or in part, to the extent necessary to eliminate such interference; provided that, if the Secretary of the Navy, or if delegated, the designated local representative reasonably determines adjacent GOVERNMENT property is available, the GOVERNMENT shall convey to the GRANTEE, without charge, a substitute Easement permitting the GRANTEE to relocate the PIPELINE, or portion thereof. The GRANTEE, at its sole expense, shall relocate any portion of the PIPELINE constructed or installed by the GRANTEE for its

purposes, as necessary to utilize the substitute Easement. The substitute Easement shall contain the same terms and conditions as those of this Easement, and shall bear the same expiration date.

16. Upon termination of this Easement, or any portion thereof, the GRANTEE, at its sole expense, shall close, render inert and cap the pipeline in compliance with then-existing applicable laws and regulations, and shall restore the PREMISES to the same or as good a condition as that which existed prior to the date of this Easement to the GRANTEE. Such restoration shall be done in a manner satisfactory to the Commanding Officer, Engineering Field Activity Northeast, Naval Facilities Engineering Command or a designated local representative.

17. The GOVERNMENT may use the PREMISES for any purpose that does not unreasonably interfere with the safety, use and enjoyment by the GRANTEE of the rights granted by this Easement.

IN WITNESS WHEREOF, the parties hereto have caused this GRANT OF EASEMENT to be executed by their duly authorized representative as of the date stated above.

UNITED STATES OF AMERICA

By [illegible]
Real Estate Contracting Officer

ATTEST:

Southern Union Company -
New England Division
d/b/a Providence Gas Company

By S. Partridge

Title Vice President, Finance & Regulatory

STATE OF RHODE ISLAND)
) To wit:
CITY OF PROVIDENCE)

I, Anne W. Connor, a Notary Public for the State OF Rhode Island, do hereby certify that Sharon Partridge, whose name as such is signed to the foregoing Easement has this day acknowledged the same before me in the City and State aforesaid.

Given under my hand this 25th day of September, 2001.

Anne W. Connor
Notary Public

My commission expires: 12/23/01.

(SEAL)

STATE OF VIRGINIA)
) To wit:
CITY OF NORFOLK)

I, Phillip A. Hakey, a Notary Public for the State at Large, do hereby certify that Richard A. Bonelli, II, whose name as such is signed to the foregoing Easement has this day acknowledged the same before me in the City and State aforesaid.

Given under my hand this 18th day of September, 2001.

Phillip A. Hakey
Notary Public

My commission expires: July 31, 2005.

(SEAL)

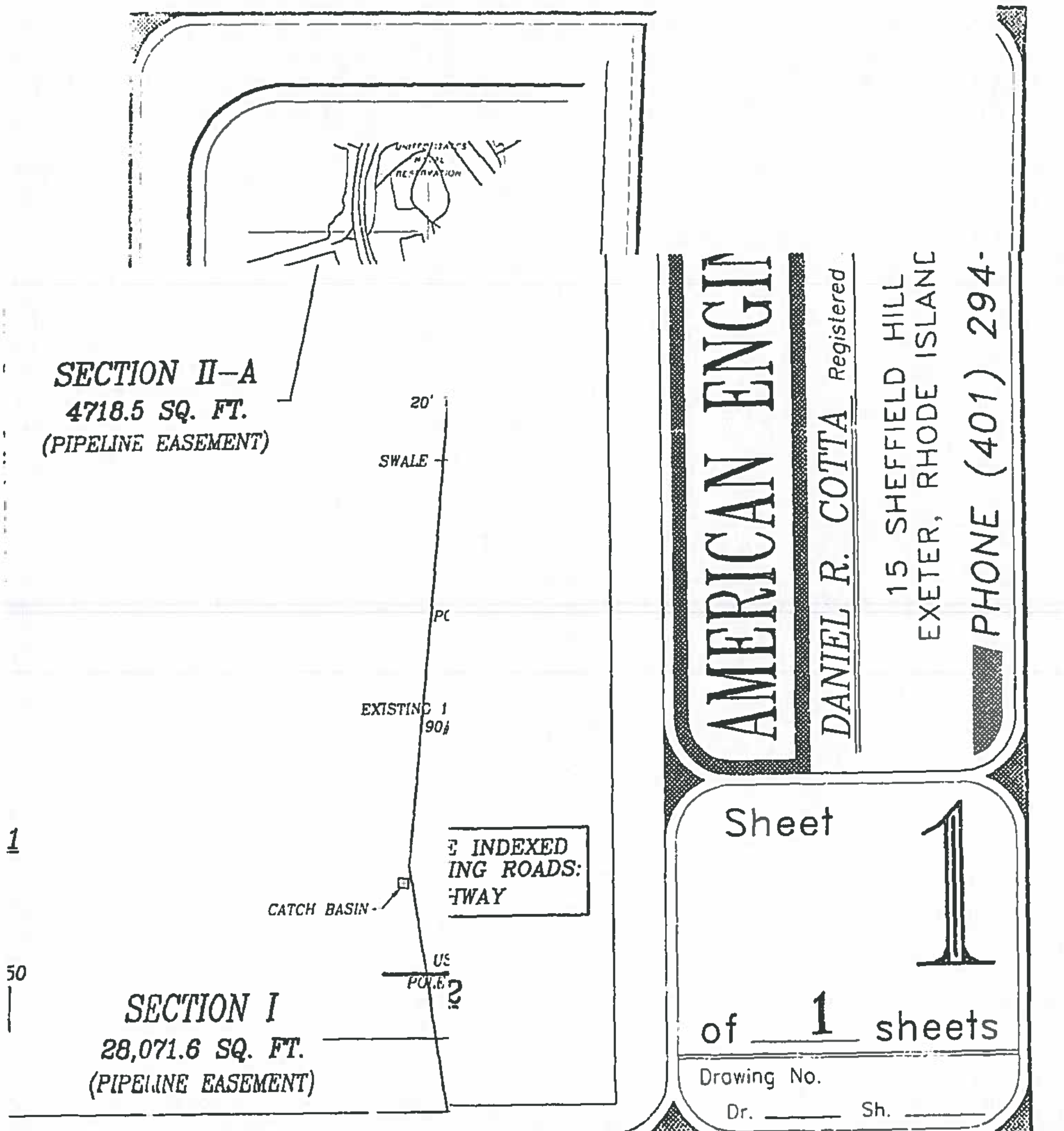


Exhibit "A" to Easement N62470-01-RP-00174

Soil Management Plan
Naval Station Newport, Newport, RI

This Soil Management Plan (SMP) has been prepared to establish procedures that will be followed should future construction, demolition or maintenance activities at the Naval Station Newport (NAVSTA) require the need to manage disturbed or excavated soil. The plan cannot be used to manage soils on Navy Installation Restoration (IR) sites, soils with known contamination, such as PCBs, asbestos, or mercury, soils regulated by the State of RI with contamination other than arsenic, and on property leased to private entities (e.g. privatized Housing).

Background

The property, located in Newport, RI, was established in 1869 with the construction of a torpedo station. The Navy War College was added in 1884 and the site was used for sailor training and housing and fueling facilities during World War II. Post WWII the property footprint and training activities were reduced while research and development efforts were increased. The soils on the property were found to contain arsenic that exceeds regulatory levels during a property-wide site investigation that included the collection and analysis of more than 1000 soil samples These soils must be removed and disposed of, or covered with Department (i.e. State of Rhode Island Department of Environmental Management) approved engineered controls, consisting of building foundations, asphalt pavement, and landscaping and environmental land use controls (ELUR) in order to prevent direct exposure to regulated soils.

Applicable Area

This SMP, and affiliated ELUR (when applicable), restricts the property to industrial or commercial usage, and pertains to the entire property. See attached site figure.

Soil Management

The direct exposure pathway is the primary concern at the site. Individuals engaged in activities at the site may be exposed through incidental ingestion, dermal contact, or inhalation of entrained soil particles if proper precautions are not taken. Therefore, the following procedures will be followed to minimize the potential of exposure.

During site work, the appropriate precautions will be taken to restrict unauthorized access to the property.

During all site/earth work, dust suppression (i.e. watering) techniques must be employed at all times. In the event that an unexpected observation or situation arises during site work, such activities will immediately stop (such as olfactory or visual evidence of waste material or contamination, PCB contamination or asbestos debris disposal). Workers will not attempt to handle the situation themselves but will contact the appropriate authority for further direction.

1 / 2010

If excess soil is generated /excavated from the property, the soil is to remain on-site for analytical testing, to be performed by an environmental professional, in order to determine the appropriate disposal and/or management options. The soil must be placed on and covered with polyethylene/plastic sheeting during the entire duration of its staging and secured with appropriate controls to limit the loss of the cover and protect against storm-water and/or wind erosion (i.e. hay bales, silt fencing, rocks, etc).

Excavated soils will be staged and temporarily stored in a designated area of the property. Within reason, the storage location will be selected to limit the unauthorized access to the materials (i.e. away from public roadways/walkways). No soil will be stockpiled on-site for greater than 60 days without prior Department approval.

Soils excavated from the site may not be re-used as fill on residential property. Excavated fill material shall not be re-used as fill on commercial or industrial properties unless it meets the Department's Method 1 Residential Direct Exposure Criteria for all constituents listed in Table 1 of the Rules and Regulations for the Investigation and Remediation of Hazardous Material Releases (Remediation Regulations).

Excavated soil to be reused on non-Navy commercial or industrial properties must be sampled and analyzed, by a qualified environmental professional, at a frequency of one sample per 500 tons for all constituents in Table 1. Copies of the laboratory analysis results shall be maintained by the site owner and included in the annual inspection report for the site, or the closure report if applicable. In the event that the soil does not meet any of these criteria, the material must be properly managed and disposed of off site at a licensed facility.

Site soils, which are to be disposed of off-site (and not reused off-site), must be done so at a licensed facility in accordance with all local, state, and federal laws. Copies of the material shipping records associated with the disposal of the material shall be maintained by the site owner and included in the annual inspection report for the site.

Best soil management practices should be employed at all times and regulated soils should be segregated into separate piles (or cells or containers) as appropriate based upon the results of analytical testing, when multiple reuse options are planned (i.e. reuse on-site, reuse at a Department approved industrial/commercial property, or disposal at a Department approved licensed facility).

All non-disposable equipment used during the soil disturbance activities will be properly decontaminated as appropriate prior to removal from the site. All disposable equipment used during the soil disturbance activities will be properly containerized and disposed of following completion of the work. All vehicles utilized during the work shall be properly decontaminated as appropriate prior to leaving the site.

At the completion of site work, all exposed soils that remain on the site (i.e. have not been removed to licensed disposal facility) are required to be recapped with Department approved engineered controls (i.e. 2 feet of clean fill or equivalent; building foundations; 4 inches of pavement/concrete underlain with 6 inches of clean fill; and/or 1 foot of clean fill underlain with a geotextile liner) consistent or better than the site surface conditions prior to the work that took place. These measures must also be consistent with the Department approved ELUR recorded on the property. Any clean fill material brought on site is required to meet the Department's Method 1 Residential Direct Exposure Criteria or be designated by an Environmental Professional as Non-Jurisdictional under the Remediation Regulations. The Annual Inspection Report for the site, or Closure Report if applicable, should include either analytical sampling results from the fill demonstrating compliance or alternatively include written certification by an Environmental Professional that the fill is not jurisdictional.

Worker Health and Safety

To ensure the health and safety of on-site workers, persons involved in the excavation and handling of the material on site are required to wear a minimum of Level D personal protection equipment, including gloves, work boots and eye protection. Workers are also required to wash their hands with soap and water prior to eating, drinking, smoking, or leaving the site.

Department Approval

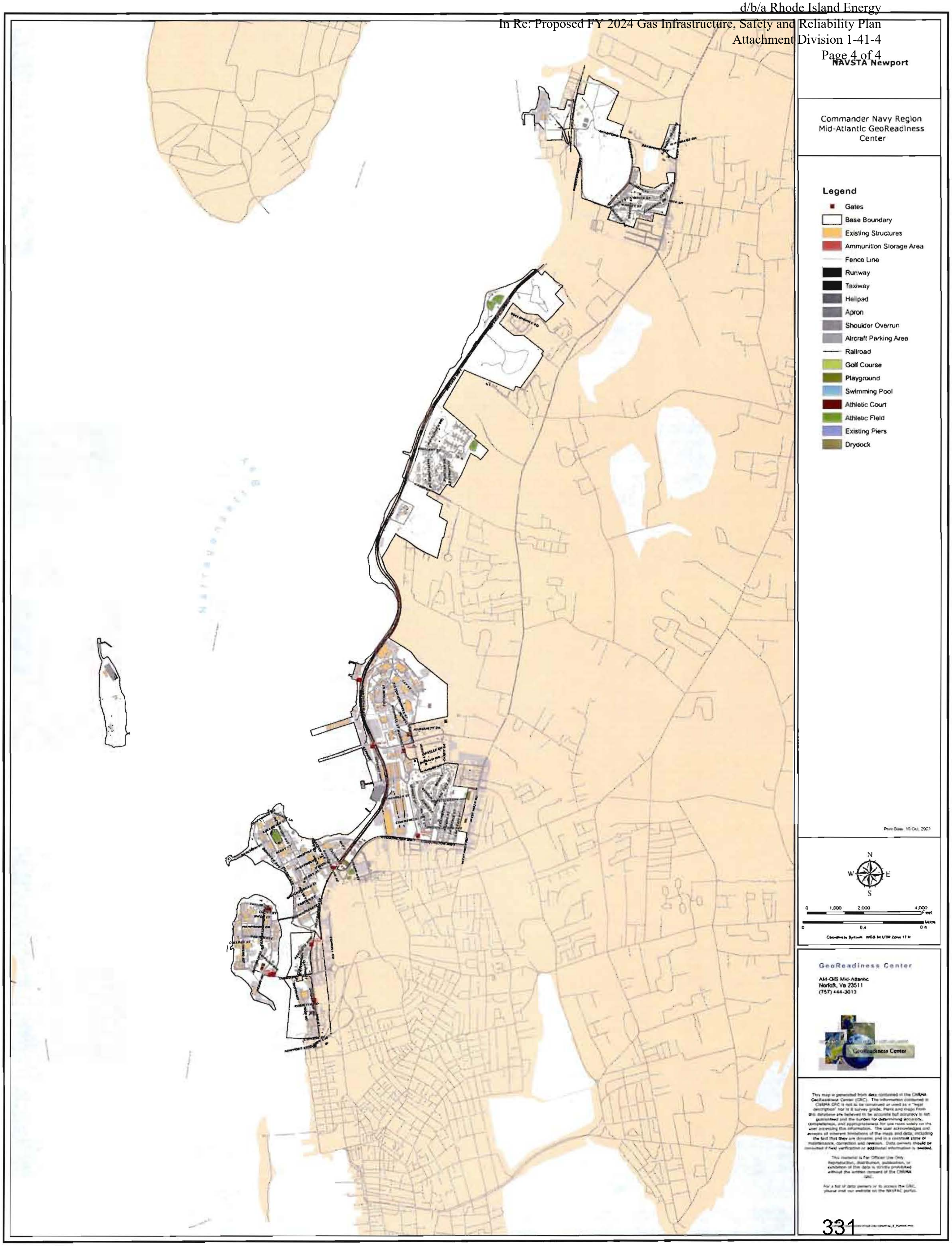
In accordance with the Departments' requirements, no soil at the property is to be disturbed after an engineering control has been implemented in any manner without prior written permission of the Department's Office of Waste Management, except for minor inspections, maintenance, and landscaping activities that do not disturb the contaminated soil that is left in place.

As part of the notification process, the Navy shall publish a notice, annually in the *Newport Daily News* that indicates that soil contain arsenic above the Department's Method 1 Direct Exposure Criteria, that soil work is planned on the property, and that individuals will be notified if work is to be done adjacent to privately-owned property.

In addition, the Navy will prepare an annual report to be submitted to the Department that summarizes construction work done on the property were soil was removed and inspections of sites on the property were soils with arsenic have been left in place and land use restrictions have been applied.

For soil that is removed, the report will identify the location, quantity, and ultimate destination. For sites with land use restrictions the inspections will include the location of the site and certification that the engineering controls remain in place.

David Dorocz, PE	Leo Hellsted, PE 6-3-10
Environmental Division Director	Chief of Office of Waste Management
Naval Station Newport	Department of Environmental Management


NAVSTA Newport
Commander Navy Region
Mid-Atlantic GeoReadiness
Center
Legend
Gates
Base Boundary
Existing Structures
Ammunition Storage Area
Fence Line
Runway
Taxiway
Helipad
Apron
Shoulder Overrun
Aircraft Parking Area
Railroad
Golf Course
Playground
Swimming Pool
Athletic Court
Athletic Field
Existing Piers
Drydock
N
W
E
S
0
1,000
2,000
4,000
Feet
Miles
0
0.4
0.8
GeoReadiness Center
AM-GIS Mid-Atlantic
Norfolk, Va 23511
(757) 444-3013
GeoReadiness Center

Division 1-42

Request:

Given the prior delays associated with the Goat Island bridge project, will the Glenbridge Avenue bridge, the Goat Island bridge, and the River Street bridge projects actually be constructed in CY 2024? Please explain.

Response:

For the Goat Island Bridge, the gas pipe is submerged during astronomical high tide, storm surges, as well as splashing from tidal waves. Rhode Island Department of Transportation ("RIDOT") has been discussing reconstruction of this bridge for the last few years and has not come to a conclusion on how/when they will replace the bridge. If/when RIDOT decides to replace the bridge, the Company would install new gas pipe to service Goat Island. In the meantime, the Company has decided to move forward with a mitigation plan. Currently there are two 4" mains on the bridge, and the Company's analysis indicates one 4" main is sufficient to provide service to Goat Island. The Company is planning to complete the design of the pipes on the island side and re-route ~~through~~ the piping through the back wall. The Engineering team is planning to complete the design and work out the logistics with RIDOT and the City of Newport in CY 2023 and complete construction in CY 2024.

Glenbridge Avenue Bridge does not face the same challenge as the Goat Island Bridge in that it is not dependent upon RIDOT's bridge work. The Company is planning to relocate the existing gas mains from the utilities bridge to the vehicular bridge and the Company is confident this work can be completed in CY 2024.

For River Street Bridge, RIDOT informed the Company after the November 2-3 meetings with the Division that a major rehabilitation is planned in 2025. The Company will work with RIDOT's design team and plan its work accordingly. Depending on the scope of the RIDOT planned work, the Company may do the gas main repair work as planned in CY 2024 if the scope of RIDOT's bridge work does not impact the gas main. Alternatively, the Company may hold off the gas main repair, until a later date, if the RIDOT bridge work necessitates the replacement of the gas main.

Prepared by or under the supervision of: Gene Au

Division 1-43

Request:

On Page 38 the Company indicates that the 17 of 18 elevated gas facilities "will have been remediated" in FY 2023. During the Walk-through the Company indicated this budget would probably be further reduced because the locations requiring remediation "will have been exhausted." Provide an update of the budget for Access Protection Mediation for CY 2023 and CY 2024.

Response:

The budgets for the 9-month CY 2023 and 12-month CY 2024 periods are being reduced from that which was submitted to the Division in the October 2022 proposal. The Company is coming to the end of the list of defined locations to remediate and access protection remediation panels will be incorporated into the design of future bridge crossings instead of being charged to this separate program. The 9-month CY 2023 budget includes the final two locations from the original list of 18 locations along with an additional two that were identified in FY 2023, as shown in the table below.

The 12-month CY 2024 budget is for general minor capital improvements that may arise with access protection remediation panels, as shown in the table below.

	Projects	**Budget**
9-Month CY 2023	SMF-0012 (new main), Esmond Mill, @ Woonsquatucket River	$0.06M
	WWW-0008, West Natick Rd @ Bald Hill, Meshanticut Brook	
	SKS-0002, 316 Columbia St, S Kingstown	
	NSF-0002 (new main), Union Village Railroad Bridge, North Smithfield	
12-month CY 2024	General Minor Capital Improvements	$0.02M

Prepared by or under the supervision of: Gene Au

Division 1-44

Request:

On Page 39 the Company indicates that it is currently maintaining two weld shops and seeks $5 M under the Reliability subcategory "Weld Shop" to "build out a new consolidated weld shop." Please,

(a) Identify the location of the two existing weld shops.

(b) Are the facilities identified in subpart (a) currently equipped with tools and equipment? Please explain.

(c) Identify how much was spent on welding that was outsourced each of the past 3 years.

(d) Provide an inventory of welding tools the Company intends to purchase for the new Weld Shop.

(e) Provide documentation that supports the $5 M budget for the new Weld Shop.

Response:

(a) The Company's existing Providence weld shop is on the ground floor of 477 Dexter Street in the back left corner of the building. The Company's existing Lincoln weld shop is in the back parking lot of 642 George Washington Highway, Lincoln in the far-right garage bay.

(b) Both weld shops are equipped with tools and equipment. The current tools and equipment would either be reused in a newly constructed weld shop or credited towards the purchase of new tooling and equipment. As a result of the larger capabilities the new weld shop building would provide, the Company would need to purchase additional equipment that is not currently equipped in the existing weld shops.

(c) The Company does not separately track welding costs as these costs are embedded within ongoing projects and are not differentiated from the overall operational costs of those projects; therefore, the Company is not able to provide a finite amount of costs spent on outsourcing welding work for each of the past three years. A new weld shop would provide Rhode Island Energy with the capability to complete welding work in-house versus having to incur the costs to outsource this work to contractors. The ability to complete the work in-house allows for better control over more welding activities, which the Company believes will translate into more timely execution of field work and improve project execution timelines, thus producing operational efficiency savings.

Division 1-44, page 2

(d) The Company intends to purchase the following welding tools for the new weld shop:

- Fabrication tables/benches
- Multi-process welding machines
- Fume extractors/filtration system
- 6+Ton Overhead crane
- Rod Ovens
- Bandsaw
- Destructive testing equipment
- Drill press
- Plasma Cutter
- Torching equipment
- Beveling equipment
- Stands/Rollers/Carts
- Industrial storage cabinets/shelving
- Pipe storage racks
- Pipe cutting/threading equipment
- Various hand tools
- Forklift
- Safety equipment
- Air Compressor

(e) The $5.00 million budget was forecasted based, in part, upon a regional average of $450-$500/sq. ft. for similar industrial buildings. Buildings that were previously built within National Grid's Northeast and New York regions were used as reference for the average square footage costs. The original budget was forecasted during the conceptual stages of the weld shop project. These initial factors did not take into consideration the required square footage for the building size, demolition costs, or tools and equipment. The current budget for the weld shop is $11.86 million. The weld shop will house welding tools and equipment, welding stock, along with providing space to perform welding operations for projects within the ISR program. The budget is proposed to cover the building costs along with associated tools and equipment. The new weld shop will be able to facilitate welding operations for work within the capital budget, along with training and qualification necessary for welding. Welding stock for projects within the capital budget will also be properly stored within the new weld shop. The Company is utilizing an existing property in a central location in which to locate the weld shop; therefore, there will be no costs associated with purchasing commercial property within Providence.

Division 1-44, page 3

The Company does not have documentation for the budget estimate currently as the project is still in the development stages. The current cost-breakdown for the new weld shop budget is as follows:

- **Demolition/Site Prep/Site Work for building** - $2.00 million: To facilitate and prepare the existing building for the new weld shop, the current operations at that location will need to be relocated, and the meter house and scale house will need to be demolished, and capped. The Company developed the budget estimate for this category based on the scope of the work from previous job sites.

- **Foundation/Building/Design Costs - $8.00 million**: The Company developed the budget estimate for this category based on a 15,000 square foot building at $480 per square foot, which is in line with the regional average noted above. The budget estimate includes an additional $0.80 million for design costs.

- **Equipment - $1.56 million**: The budget estimate for this category is based on national averages and broken down as follows:

    - Smoke evacuation units ($0.25 million)
    - Approximate 6-Ton overhead crane ($1.00 million)
    - Forklift ($0.06 million)
    - Air compressor ($0.25 million)

- **Tools/Tooling - $0.30 million**: Please see the response to subpart (d), above, for a list of the tools the Company intends to purchase for the new weld shop. The budget estimate for this category is based on national averages.

Total: $11.86 million

Division 1-45

Request:

Regarding the Southern RI Gas Expansion Project on Page 40, provide a more detailed description of the work proposed for the Cranston Regulator Station.

Response:

The Laten Knight Cranston Take Station Project will entail removing the existing regulator runs and existing regulator portion of the United Concrete building, installation of a new building extension, two new regulator runs with a new 200# outlet for the station tying into the existing Kinder Morgan pipeline at the Line of Demarcation. The project will also require installing a new United Concrete DAC/GC building, new fencing with updated Alternating Current (AC) mitigation system, necessary due to nearby electric transmission lines, and a new access road with proper storm water management system. This project will be broken into two seasons because of the short outage window. The civil construction portion, including access road, fencing, and AC mitigation systems will be completed during the 9-month period of CY 2023; the remainder of the project will be completed during the 12-month period of CY 2024.

Prepared by or under the supervision of: Tom Mulkeen

Division 1-46

Request:

Provide the Company's FY 2023 Gas ISR Quarterly Update ending September 30, 2022 and the Company's FY 2023 Gas ISR Quarterly Report Update ending December 31, 2022 (no later than February 15, 2022).

Response:

Please see Attachment DIV 1-46 for a copy of the Company's FY 2023 Q2 ISR Quarterly Report that the Company filed with the Rhode Island Public Utilities Commission on November 16, 2022. The Company will file the FY 2023 Q3 ISR Quarterly Report for the period ending December 31, 2022, by February 15, 2023.

Robinson+Cole

STEVEN J. BOYAJIAN

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Also admitted in Massachusetts

November 16, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5210 - FY 2023 Gas Infrastructure, Safety, and Reliability Plan
Quarterly Update - Second Quarter Ending September 30, 2022

Dear Ms. Massaro:

On behalf of Rhode Island Energy,[1] I have enclosed an electronic version of the Company's fiscal year (FY) 2023 Gas Infrastructure, Safety, and Reliability (ISR) Plan quarterly update for the second quarter ending September 30, 2022.[2] Pursuant to the provisions of the approved FY 2018 Gas ISR Plan, the Company committed to providing quarterly updates on the progress of its Gas ISR program to the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-709-3359.

Very truly yours,

Steven J. Boyajian

Enclosures
cc: Docket 5210 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 a 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.

Gas Infrastructure, Safety, and Reliability Plan

The Narragansett Electric Company

FY 2023 Quarterly Update

Second Quarter - Ending September 30, 2022

Executive Summary

Fiscal year ("FY") 2023 Gas Infrastructure, Safety and Reliability ("Gas ISR Plan" or the "Plan") second quarter results (Attachment A) reflect that the Company[1] has spent approximately $92.69 million of an estimated year-to-date (YTD) budget of $102.92 million, resulting in a second quarter underspending variance of $10.23 million. The total spending of $92.69 million (see Attachments A & B) is comprised of $89.77 million for the Gas ISR Plan, excluding the Southern Rhode Island Gas Expansion Project ("Gas ISR") and $2.92 million for the Southern Rhode Island Gas Expansion Project ("Gas Expansion Project"). To date, the $92.69 million of actual spending represents 53 percent of the total FY 2023 annual Gas ISR Plan budget of $175.66 million. As of September 30, 2022, the forecasted total year-end spend was $164.98 million, which was $10.68 million below the total budget of $175.66 million.

The Gas ISR (excluding Gas Expansion Project) spend thru the end of the second quarter was $89.77 million and includes actual spending of $14.13 million out of an estimated YTD budget of $26.01 million for Non-Discretionary work, resulting in a second quarter underspending variance of $11.87 million. In addition, the spend thru the second quarter includes actual spending of $75.64 million of an estimated YTD budget of $72.70 million on Discretionary work, resulting in a second quarter overspending variance of $2.93 million. Excluding the Gas E xpansion Project, as of September 30, 2022, the forecasted year-end spend for the Gas ISR was

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

$159.71 million, which was $9.16 million below the annual budget for Gas ISR. Forecast decreases in CSC/Public Works, Meter Purchases, Reactive Leaks, Reactive Main Replacement, Low Pressure System Elimination, Transmission Station Integrity, Pressure Regulating Facilities, Gas System Reliability, LNG (Exeter) categories, along with Public Works – Reimbursements (credits) that are forecasted to be higher than budget, are the primary drivers of the projected underspend. Decreases in those categories are partially offset by forecasted overspend in the Main Replacement (Proactive) - Leak Prone Pipe, Proactive Main Replacement – Large Diameter LPCI, Allens Avenue Multi Station Rebuild, Atwells Avenue, CSC/Public Works Reimbursable, and Tools & Equipment categories, along with the addition of the LNG – Portable Equipment Purchase category.

The Gas Expansion Project incurred spending thru the second quarter of $2.92 million out of an estimated YTD budget of $4.21 million, resulting in a second quarter underspending variance of $1.29 million. As of September 30, 2022, the forecasted year-end spend was $5.263 million, which was $1.52 million below the annual budget for the Gas Expansion Project. Forecasted underspending in the Other Upgrades/Investments and Regulator Station Investment categories are the primary drivers of the projected underspending.

FY 2023 Capital Spending by Category

Non-Discretionary Work[2]

Public Works Program – $7.01 million variance under year-to-date budget

Through the second quarter of FY 2023, the Company spent $5.25 million, net reimbursements, against a projected year-to-date budget of $12.26 million for the Public Works program, resulting in an underbudget variance of $7.01 million. To date, for FY 2023, the Company has installed 1.2 miles of a plan of 8.1 miles of new replacement gas main and has abandoned 4.4 miles of a plan of 7.9 miles of leak-prone pipe through the Public Works program. The volume of workable work did not materialize in time to execute the budgeted volume of Public Works projects in FY 2023, mainly due to the timing of when the project requests were submitted into the Company, but the requested projects have now been received and the Company is in good position to execute that work in the in the remaining months of CY 2023 following the close of FY 2023 on March 31. The Company was able to shift the resources (crews and dollars) from Public Works into the Proactive Main Replacement program, which is the main driver of the Public Works underbudget variance and Proactive Main Replacement overbudget variance. The Company forecasts that FY 2023 Reimbursements (credits) will total $4.30 million, which is $2.87 million higher than budget. As a result, the Public Works Program category is projected to be underbudget by $14.17 million at fiscal year-end.

[2] Non-Discretionary programs include projects that are required by legal, regulatory code, and/or agreement, or are the result of damage or failure, with limited exceptions.

Mandated Programs – $4.85 million underspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company has spent approximately $8.89 million of a projected YTD budget of $13.74 million for Mandated Programs, resulting in an actual to budget variance of $4.85 million. The primary drivers of the underspend in the Mandated category are lower than anticipated costs in the Purchase Meter, Reactive Main Replacement – Maintenance, and Transmission Station Integrity categories. For the Purchase Meter category, the Company is actively managing through supply chain challenges that are impacting the delivery of various sized gas meters and it may have an impact on the Company's ability to receive certain larger size specialty meters from our suppliers in FY 2023. This category is forecast to be underbudget by $1.86 million at fiscal year-end. The Reactive Main Replacement – Maintenance category is currently underspent YTD because the Oxbow Farms project in Middletown, Rhode Island has not yet started, as the Company is continuing to evaluate the approach for the project scope with the housing development owner. The Transmission Station Integrity program is currently underbudget and is forecasted to be underspent by $4.14 million at fiscal year-end as the records review process (OPEX – Non-ISR) has taken longer than expected due to COVID-19 related delays, which have in turn delayed the ISR/Capital related activities. Additionally, the Scott Road project, which is a full station and heater replacement, is underbudget for FY 2023 as additional time has been required to coordinate the site and station design, which shifted some spending into the 9-month period of CY 2023 following the close of FY 2023 on March 31. As a result of the factors detailed above, the Mandated category is forecasted to be underbudget by $11.52 million at fiscal year-end.

In June 2021, the Company, in collaboration with the Rhode Island Division of Public Utilities and Carriers ("Division"), developed and implemented a plan to continuously improve the Company's tracking of its meter inventory and its purchasing strategies. This was implemented in compliance with the PUC's Order in the Company's FY 2022 Gas ISR Plan, Docket No. 5099. The first component of the plan is an enhanced process to track meter inventory. The

Company is conducting a manual count of the meter lab inventory each month until the Company has validated that the Maximo system is accurately capturing inventory data. The Company conducted a physical inventory count on June 10, 2021 to establish the baseline count. The chart below provides a summary of the meter lab inventory counts on June 10, 2021, and the closest date to the close of each quarter that followed, which were June 30, 2021, September 30, 2021, January 3, 2022, March 31, 2022, June 30, 2022, and September 30, 2022. The Company is continuing to review the variances between the physical counts and the meter inventory tracked in Maximo, and working to address factors that contribute to the variance, including the timing of when inventory is counted, when reports are run, and the timing of data cleanup in the Maximo system.

Meter Lab Inventory				
Measure	**Physical Count**	**Maximo**	**Variance**	**Variance %**
Inventory as of 6/10/2021	9,943	10,926	983	9%
Inventory as of 6/30/2021	9,156	9,988	823	8%
Inventory as of 9/30/2021	9,568	10,370	802	8%
Inventory as of 1/3/2022*	9,994	10,986	992	9%
Inventory as of 3/31/2022	11,724	12,605	881	7%
Inventory as of 6/30/2022	7,354	8,164	810	10%
Inventory as of 9/30/2022	6,513	7,452	939	13%

***Due to Vacations, the Meter Lab gathered inventory data the first Monday after New Years.**

Damage/Failure Reactive Program – $0.01 million variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent $0 of a projected YTD budget of $0.01 million for the Damage/Failure Reactive program, resulting in an under-budget variance of $0.01 million. At this time, the Damage/Failure Reactive program category is forecasted to be on budget at fiscal year-end.

Discretionary Work[3]

Proactive Main Replacement Program – $5.70 million overspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent approximately $54.70 million of a projected YTD budget of $49.00 million for the Proactive Main Replacement programs, resulting in an overspending variance of approximately $5.70 million. To date, for FY 2023 in the Proactive Main Replacement ("MRP") Program, the Company has installed 32.1 miles of new replacement gas main against a plan of 32.0 miles. Across all ISR programs, the Company has installed a total of 36.8 miles of new replacement gas main against a plan of 44.0 miles. Fiscal YTD, the Company has abandoned 18.6 miles in the MRP Program against a plan of 27.9 miles. Across all ISR programs, the Company has abandoned 23.0 miles against an overall plan of 36.4 miles. Although the Company is behind the YTD targets for installation and abandonment, good progress has been made on planned projects and construction work, in the mandated and reliability categories, which draw from the same resources required to abandon main. That clears the way to put the Company is in a good position to execute and achieve the installation and abandonment mileage targets for FY 2023. Additionally, as mentioned above in the Public Works categories and Maintenance category, the volume of FY 2023 work that was budgeted for those categories did not fully materialize to be executable within FY 2023. However, the Company was able to shift resources (crews and dollars) from Public Works and Maintenance to the Proactive Main Replacement programs, which is the primary driver of the overbudget variance in the Proactive Main Replacement programs.

[3] Discretionary programs are not required by legal, regulatory code, or agreement, or a result of damage or failure, with limited exceptions.

Through the second quarter of FY 2023, the Proactive Main Replacement – Large Diameter LPCI Program is overbudget YTD and is forecast to exceed the budget by $1.87 million at fiscal year-end. The original budget called for two Cast Iron Sealing Robot Joint ("CISBOT") jobs, but based on Contractor availability, project readiness, moderate Company resource requirements for this type of work, and budget availability (offset by Public Works – Reimbursements), the Company is now forecasting to complete four CISBOT projects in FY 2023.

For the Atwells Avenue Project, the Company is on pace to have final restoration for Segments 1A and 1B completed by the end of Q3 FY 2023. As of the date of this report, the last steps to be completed are line striping (center lines and parking/valet lines) and receipt/payment of vendor invoices. The final restoration work for DePasquale Square was started in October 2022 and was completed in November 2022; this was completed ahead of schedule, so the $0.40 million that was budgeted for this work has been added to the FY 2023 forecast included in this report and will be removed from the 9-month CY 2023 budget. Segment 3 of the project was budgeted to be completed in FY 2023, but the project has been deferred into the 9-month CY 2023 period, as the Company is continuing to work in close conjunction with Providence Water (replacing water pipe) and the City of Providence (replacing leak prone pipe ahead of municipal paving) to address the highest priority work, with the majority of the FY 2023 work being completed on the East Side area of Providence. The $1.10 million associated with the Atwells Avenue Segment 3 work has been removed from the FY 2023 forecast and was included in the 9-month CY 2023 budget proposal as part of the proposed FY 2024 ISR Plan that the Company submitted to the Division in October 2022.

Proactive Service Replacement Program – $0.19 million underspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent $0.17 million of a projected YTD budget of $0.37 million for the Proactive Service Replacement Program ("SRP"), resulting in an underspending variance of $0.19 million. The Company is continuing to focus on replacing the remaining 25 copper services located in Cumberland; YTD 23 of the 25 copper services have been replaced. The customers/property owners of the final 2 copper services in Cumberland have been reluctant to allow their service replacements, but the Company continues to pursue those replacements. The Company has also replaced another 11 services as part of this program, which includes 1 high-pressure inside set, 7 steel services on plastic, and 3 services in the Providence area. The Company is also continuing to review the population of services that were originally included on the Proactive Service Replacement list and has been conducting written customer outreach as accounts are being confirmed as leak-prone services on main that is not leak-prone. At this time, the Proactive Service Replacement Program category is forecasted to be underbudget by $0.37 million at fiscal year-end.

Reliability Programs – $2.57 million underspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent $20.76 million of a projected YTD budget of $23.33 million for Reliability programs, resulting in an underspending variance of $2.57 million for this category. As of September 30, 2022, the Reliability programs were projected to be overbudget by $1.33 million at fiscal year-end. The timing of work is the primary driver of the YTD underspending variance, as most categories that are currently underspent are still forecasted to be on or close to budget at fiscal year-end. The Pressure Regulating Facilities, LNG and Gas System Reliability categories are underbudget YTD, due to the timing of work, and are forecasted to remain underbudget at fiscal year-end. The Enbridge Heaters Replacement and Asset Transfer projects (Tiverton and Wampanoag Trail) are currently underbudget based on the timing of outgoing progress payments and those projects are forecasted to be slightly over budget at fiscal year-end due to bid pricing, which increased the total costs the Company will reimburse to Enbridge. The Allens Avenue Multi Station Rebuild project that flowed into FY 2023 from FY 2022 for work associated with the Chromatograph building and additional work associated with abandonment is forecasted to spend $1.14 million by fiscal year-end and had $0 budgeted for FY 2023. The Tools & Equipment budget is also forecast to be overbudget at fiscal year-end by approximately $0.86 million as certain specialty equipment that was ordered, but not delivered, in FY 2022, and will now be received in FY 2023. A review of the Company's tools & equipment was conducted as part of the separation from National Grid USA. The Company determined that certain specialty equipment needed to be purchased, in part, because Rhode Island Energy could no longer borrow the equipment from National Grid USA affiliates, such as The Boston Gas Company. Rhode Island Energy concluded that having full-time access to the equipment would enhance the safety and efficiency of capital projects. Examples of specialty equipment no longer available to be borrowed are Kleiss systems, T.D. Williamson equipment, and hole hogs.

The Company will also incur charges of $7.00 million in FY 2023, which was not originally in the budget, for costs associated with down payments for Portable LNG Equipment that will primarily be used at the Cumberland LNG Facility. That equipment will be placed in service in the 9-month period of CY 2023 following the close of FY 2023 on March 31. The Company currently contracts the Portable LNG Equipment and Operations for the Cumberland facility and that contract, which was originated in 2018 and was extended during the COVID-19 pandemic, expires at the close of Winter 2022-2023. The Company has performed a cost-benefit and operational analysis of entering into a new contract versus purchasing new Portable LNG Equipment and operating it internally. The Company has determined that purchasing the equipment is in the best interest of Rhode Island gas customers from several perspectives:

- <u>Cost:</u>
    - Predictable costs for rate payers – not subject to increasing market fluctuations; and
    - Equipment has resale value if no longer needed for Cumberland or the overall Rhode Island Energy territory.

- System Reliability:
  - Available to serve Cumberland site during the winter of upcoming years;
  - Available to support Cumberland LNG's long term solution during construction (in scenario where permanent LNG facilities are permitted for that site); and
  - Can serve all Rhode Island Energy customers and respond to system issues or pipeline operations without having to request proposals or rely on availability of contractors and equipment which may not be readily available in the region.
- Operational:
  - Operation will have increased system redundancy with multiple pumps (as opposed to the single pump system that the Company presently rents;
  - Two vaporizers will provide redundancy with plant's fixed vaporizers;
  - SCADA integration will allow full monitoring of the pumper units inside the control room for enhanced safety;
  - Rhode Island Energy LNG team has extensive experience operating fixed LNG equipment. Bringing Portable LNG operations in-house will position company to expedite response to system needs; and
  - Equipment is portable and can be moved to support the system anywhere in the state as necessary.

FY 2023 Southern Rhode Island Gas Expansion Project Spending by Category

Construction

Pipeline – $0.27 million underspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent $0.13 million of a projected YTD budget of $0.39 million for the Gas Expansion Project – Main Installation, resulting in an underspending variance of $0.27 million for this category. The spending in this category for FY

2023 is for closeout costs related to the Main Installation final restoration. This category is forecast to be on budget at fiscal year-end.

Other Upgrades/Investments

Maximum Operating Pressure (MOP) Project, Launcher/Receiver, Installation of Remote Operating Valve (ROV) – $0.21 million underspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent $0.001 million of a projected YTD budget of $0.21 million for the Other Upgrades/Investments category, resulting in an underspending variance of $0.21 million for this category. In FY 2023, the Company will be completing closeout activities for the Maximum Operating Pressure project and is forecasted to be under budget by approximately $0.05 as actual costs are projected to be lower than budget. The Company budgeted $0.35 million for the Launcher-Receiver/ Install ROV portion of this budget for investigation and design work but is forecasted to be under budget by $0.30 million at fiscal year-end. The Company is conducting additional analysis to determine the viability of the Launcher-Receiver and/or Remote Operated Valve ("ROV") within Rhode Island Energy's operating system and is not planning to progress this work during CY 2023 or CY 2024. At this time, the Other Upgrades/Investments category is projected to be underbudget at fiscal year-end by $0.38 million.

Regulator Station Investment

Updates to Cranston Regulator Station, Cowesett Regulator Station, and New Regulator Station – $0.81 million underspending variance to budget year-to-date

Through the second quarter of FY 2023, the Company spent $2.80 million of a projected YTD budget of $3.61 million for the Regulator Station Investment category, resulting in an underspending variance of $0.81 million for this category. The YTD focus of this category has been Upgrades at the Cowesett Regulator Station. The new regulator pit at this location is forecasted to be gassed-in in Q3 FY 2023, which is ahead of schedule. The spending related to the New Regulator Station near the Cowesett Regulator Station is forecasted to be underbudget by $0.65 million at fiscal year-end; the FY 2023 activity will be focused on survey work, design work, and identifying desired station location(s), so the project materials purchasing will likely be deferred until FY 2024 to align with future project construction. This deferral has been incorporated into the FY 2024 ISR Plan submitted to the Division in October 2022. The Cranston Regulator Station Upgrades project is forecasted to be under budget by $0.50 million at fiscal year-end as some elements of the project scope/construction plan required re-design to accommodate stop gas work on Rhode Island Energy’s system versus the transmission company’s system. At this time, the Regulator Station Investment category is projected to be underbudget by $1.15 million at fiscal year-end.

Plant-in-Service Forecast

As of the close of Q2 FY 2023, the Company is forecasting to place Capital Additions In-Service of $154.52 versus a target of $164.47, resulting in a forecasted under-target variance of $9.95million. The FY 2023 In-Service forecast may increase by $5.23 million if the Take Station Enhancement Program - Tiverton Gate Station Ownership Transfer (“Tiverton GS Heater & Asset Transfer”) is able to be brought online before the close of FY 2023.

Attachment A
RIPUC Docket No. 5210
FY 2023 Gas Infrastructure, Safety, and Reliability Plan
FY 2023 Quarterly Update

Attachment A - Summary

The Narragansett Electric Company
d/b/a Rhode Island Energy - RI Gas
Capital Spending by Investment Categories - Summary
FY 2023 through September 30, 2022
($000)

Categories	FYTD Budget	FYTD Actual	FYTD Variance		FY 2023 - Total Budget	FY 2023 - Total Forecast	FY 2023 - Total Variance
NON-DISCRETIONARY							
Public Works [1]	$12,256	$5,248	($7,008)		$20,600	$6,433	($14,167)
Mandated Programs	$13,738	$8,886	($4,853)		$28,360	$16,845	($11,515)
Damage / Failure (Reactive)	$13	$0	($13)		$25	$25	$0
NON-DISCRETIONARY TOTAL	**$26,007**	**$14,134**	**($11,873)**		**$48,985**	**$23,303**	**($25,682)**
DISCRETIONARY							
Proactive Main Replacement	$49,002	$54,703	$5,700		$78,918	$94,486	$15,568
Proactive Service Replacement	$366	$172	($194)		$600	$230	($370)
Reliability	$23,335	$20,761	($2,574)		$40,363	$41,692	$1,329
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$72,703**	**$75,635**	**$2,932**		**$119,881**	**$136,408**	**$16,527**
Southern RI Gas Expansion Project	$4,207	$2,921	($1,286)		$6,789	$5,264	($1,525)
DISCRETIONARY TOTAL (With Gas Expansion)	**$76,910**	**$78,557**	**$1,647**		**$126,670**	**$141,672**	**$15,002**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$98,710**	**$89,769**	**($8,941)**		**$168,866**	**$159,711**	**($9,155)**
CAPITAL ISR TOTAL (With Gas Expansion)	**$102,917**	**$92,691**	**($10,226)**		**$175,655**	**$164,975**	**($10,680)**
Additional Capital Investments (Not currently included in the ISR)	$1,250	$51	($1,199)		$3,500	$539	($2,961)

( ) in Variance column denotes an underspend
1. Public Works Program includes reimbursements which will be credited as received throughout the year.

Attachment B
RIPUC Docket No. 5210
FY 2023 Gas Infrastructure, Safety, and Reliability Plan
FY 2023 Quarterly Update

Attachment B - Breakout

The Narragansett Electric Company
d/b/a Rhode Island Energy - RI Gas
Capital Spending by Investment Categories - Detail
FY 2023 through September 30, 2022
($000)

	FYTD				FY 2023 - Total		
Categories	**Budget**	**Actual**	**Variance**		**Budget**	**Forecast**	**Variance**
NON-DISCRETIONARY							
Public Works							
CSC/Public Works - Non-Reimbursable	$12,262	$6,829	($5,433)		$20,596	$8,296	($12,300)
CSC/Public Works - Reimbursable	$739	$1,291	$551		$1,437	$2,437	$1,000
CSC/Public Works - Reimbursements	($745)	($2,871)	($2,126)		($1,433)	($4,300)	($2,867)
Public Works Total	**$12,256**	**$5,248**	**($7,008)**		**$20,600**	**$6,433**	**($14,167)**
Mandated Programs							
Corrosion	$679	$738	$59		$1,305	$1,305	$0
Purchase Meter (Replacement)	$2,624	$2,016	($608)		$5,248	$3,388	($1,860)
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	$5,206	$4,602	($604)		$10,100	$8,200	($1,900)
Service Replacement (Reactive) - Non-Leaks/Other	$1,919	$1,173	($746)		$1,697	$1,697	$0
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	$925	$221	($704)		$3,000	$1,000	($2,000)
Low Pressure System Elimination (Proactive)	$460	$90	($370)		$2,000	$700	($1,300)
Transmission Station Integrity	$1,716	$47	($1,669)		$4,510	$370	($4,140)
Pipeline Integrity - IVP - Wampanoag Trail Pipeline Replacement	$210	$0	($210)		$500	$185	($315)
Mandated Total	**$13,738**	**$8,886**	**($4,853)**		**$28,360**	**$16,845**	**($11,515)**
Damage / Failure (Reactive)							
Damage / Failure (Reactive)	**$13**	**$0**	**($13)**		**$25**	**$25**	**$0**
NON-DISCRETIONARY TOTAL	**$26,007**	**$14,134**	**($11,873)**		**$48,985**	**$23,303**	**($25,682)**
DISCRETIONARY							
Proactive Main Replacement							
Main Replacement (Proactive) - Leak Prone Pipe	$45,669	$49,940	$4,271		$75,204	$87,783	$12,579
Main Replacement (Proactive) - Large Diameter LPCI Program	$2,250	$2,963	$713		$2,250	$4,118	$1,868
Atwells Avenue	$1,083	$1,800	$716		$1,464	$2,585	$1,121
Proactive Main Replacement Total	**$49,002**	**$54,703**	**$5,700**		**$78,918**	**$94,486**	**$15,568**
Proactive Service Replacement							
Proactive Service Replacement Total	**$366**	**$172**	**($194)**		**$600**	**$230**	**($370)**
Reliability							
System Automation	$472	$326	($146)		$800	$800	$0
Heater Installation Program	$386	$358	($29)		$1,242	$1,154	($88)
Heater Installation Program - Wampanoag Trail Heaters Replacement and Ownership Transfer	$2,783	$3,509	$726		$4,349	$4,450	$101
Pressure Regulating Facilities	$4,703	$2,546	($2,156)		$7,585	$5,585	($2,000)
Allens Ave Multi Station Rebuild	$0	$935	$935		$0	$1,135	$1,135
Take Station Refurbishment	$290	$551	$261		$1,150	$1,154	$4
Take Station Enhancement Program -Tiverton GS Ownership Transfer	$2,899	$1,822	($1,076)		$4,529	$4,650	$121
Valve Installation/Replacement (incl Storm Hardening & Middletown/Newport)	$730	$2	($728)		$988	$350	($638)
Gas System Reliability	$1,565	$128	($1,437)		$3,260	$500	($2,760)
I&R - Reactive	$633	$648	$16		$1,375	$1,375	$0
Distribution Station Over Pressure Protection	$1,410	$1,518	$108		$3,000	$2,500	($500)
LNG	$6,375	$5,907	($467)		$10,089	$8,880	($1,209)
LNG - Portable Equipment Purchase	$0	$1,421	$0		$0	$7,000	$7,000
Replace Pipe on Bridges	$450	$29	($421)		$900	$200	($700)
Access Protection Remediation	$54	$119	$64		$272	$272	$0
Tools & Equipment	$586	$943	$357		$824	$1,687	$863
Reliability Total	**$23,335**	**$20,761**	**($2,574)**		**$40,363**	**$41,692**	**$1,329**
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$72,703**	**$75,635**	**$2,932**		**$119,881**	**$136,408**	**$16,527**
Southern RI Gas Expansion Project							
Pipeline	$390	$125	($265)		$600	$600	$0
Other Upgrades/Investments	$210	$1	($209)		$396	$21	($375)
Regulator Station Investment	$3,607	$2,796	($811)		$5,793	$4,643	($1,150)
Southern RI Gas Expansion Project Total	**$4,207**	**$2,921**	**($1,286)**		**$6,789**	**$5,264**	**($1,525)**
DISCRETIONARY TOTAL (With Gas Expansion)	**$76,910**	**$78,557**	**$1,647**		**$126,670**	**$141,672**	**$15,002**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$98,710**	**$89,769**	**($8,941)**		**$168,866**	**$159,711**	**($9,155)**
CAPITAL ISR TOTAL (With Gas Expansion)	**$102,917**	**$92,691**	**($10,226)**		**$175,655**	**$164,975**	**($10,680)**
Additional Capital Investments (Not currently included in the ISR)							
Aquidneck Island Long Term Capacity Options	$0	$39	$39		$1,000	$39	($961)
LNG - Cumberland Tank Replacement	$1,250	$12	($1,238)		$2,500	$500	($2,000)

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was 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.

Brenda L. Vucci

Brenda L. Vucci

November 16, 2022
Date

Docket No. 5210- RI Energy's FY 2023 Gas Infrastructure, Safety and Reliability (ISR) Plan - Service List 8/15/2022

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Division 1-47

Request:

Provide all leak receipts for CY 2021 by month and type (Grade 1, 2, 2a or 3). Please separate main leaks from service leaks.

Response:

Please see table below for the requested information. Leaks categorized as "Unknown" are unrepaired such that the Company has not determined whether it is on a main or service.

Month	Main/Service Leak	Grade 1	Grade 2A	Grade 2	Grade 3	Grand Total
JAN	**Main**	34	17	31	1	**83**
	Service	21	6	16		**43**
	Unknown	1	7	8	26	**42**
FEB	**Main**	27	13	10	2	**52**
	Service	22	2	1		**25**
	Unknown	3	3	10	16	**32**
MAR	**Main**	19	10	29	1	**59**
	Service	20	4	8		**32**
	Unknown	5	1	11	33	**50**
APR	**Main**	9	3	38	1	**51**
	Service	29	3	13	3	**48**
	Unknown	7		28	75	**110**
MAY	**Main**	8	3	18	1	**30**
	Service	35	1	7	2	**45**
	Unknown	5	4	15	37	**61**

Prepared by or under the supervision of: Barry Foster

Division 1-47, page 2

Month	Main/Service Leak	Grade 1	Grade 2A	Grade 2	Grade 3	Grand Total
	Main	15	4	15		**34**
	Service	34	3	7	1	**45**
JUN	**Unknown**	3	1	9	49	**62**
	Main	7		13		**20**
	Service	34	5	15		**54**
JUL	**Unknown**	7	2	22	42	**73**
	Main	8	1	6	3	**18**
	Service	28	1	6		**35**
AUG	**Unknown**	7	2	8	53	**70**
	Main	7		8		**15**
	Service	23	2	3		**28**
SEP	**Unknown**	14	4	17	47	**82**
	Main	8		8	2	**18**
	Service	34	2	4		**40**
OCT	**Unknown**	14	2	16	37	**69**
	Main	10		2		**12**
	Service	13	1			**14**
NOV	**Unknown**	12	2	14	32	**60**
	Main	5				**5**
	Service	7	1		1	**9**
DEC	**Unknown**	24	2	23	22	**71**
	Grand Total	**559**	**112**	**439**	**487**	**1597**

Division 1-48

Request:

Identify the basis for the continued increase in Workable Leak Backlog since 2017 and explain what the Company is doing to reduce the backlog to levels experienced between 2012 and 2017.

Response:

The backlog rose in 2018 as a result of the Company's transition to a new mapping system and resulting difficulties in dispatching work.

Since that time, the backlog has remained high for a number of reasons including:

- Decreases in available gas technicians due to attrition (as a result of retirements and deaths) and the reassignment of Field Ops crew members to Crew Leaders as existing employees with seniority filled internal positions offered to them per labor agreement requirements.

- Greater than expected leak receipts resulting from public odor calls during the COVID-19 Pandemic which resulted in approximately 250 leak receipts over expectations during CY 2020.

- Some Grade 3 Leaks which were not confirmed to be remediated after Main Replacement Projects were completed.

To address this issue, the Company has hired additional technicians and implemented a process that reviews all reported Grade 3 Leaks that need to be closed out due to completed Main Replacement Projects.

As a result of these two efforts, the current FY 2023 backlog is now at 2,703.

  - Grade 2/2a = 112
  - Grade 3 = 2,591

Prepared by or under the supervision of: Lauren Maclean

Division 1-49

Request:

Provide Table 1 (Page 43) for FY 2017-2021.

Response:

Please see Attachment Division 1-49 for Gas ISR actual spending for FY 2017 through FY 2022.

Table 1

RI Energy (formerly National Grid) - Gas ISR - FY2017 - FY2022 Actual Spending

($millions)

Categories	FY17 Actual	FY18 Actual	FY19 Actual	FY20 Actual	FY21 Actual	FY22 Actual
NON-DISCRETIONARY						
Public Works						
CSC/Public Works - Non-Reimbursable	*$ 8.39*	*$ 13.33*	*$ 14.29*	*$ 16.29*	*$ 14.00*	*$ 18.95*
CSC/Public Works - Reimbursable	*$ 1.54*	*$ 1.37*	*$ 0.54*	*$ 1.04*	*$ 0.69*	*$ 3.90*
CSC/Public Works - Reimbursements	*$ (1.33)*	*$ (0.12)*	*$ (1.25)*	*$ (0.81)*	*$ (1.69)*	*$ (0.60)*
Public Works Total	***$ 8.60***	***$ 14.59***	***$ 13.57***	***$ 16.52***	***$ 13.00***	***$ 22.26***
Mandated Programs						
Corrosion	*$ 0.75*	*$ 0.58*	*$ 0.27*	*$ 0.94*	*$ 2.14*	*$ 2.28*
Purchase Meters (Replacement)	*$ 1.66*	*$ 3.56*	*$ 4.15*	*$ 5.13*	*$ 5.13*	*$ 3.27*
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	*$ 10.42*	*$ 11.50*	*$ 11.40*	*$ 9.46*	*$ 7.75*	*$ 9.01*
Service Replacements (Reactive) - Non-Leaks/Other	*$ 2.15*	*$ 1.90*	*$ 1.69*	*$ 1.83*	*$ 1.33*	*$ 1.14*
Service Replacements - BS HP Leak-Prone Services	*$ 0.06*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	*$ 0.80*	*$ 0.43*	*$ 1.26*	*$ 1.48*	*$ 1.12*	*$ 1.55*
Low Pressure System Elimination (Proactive)	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 0.65*
Transmission Station Integrity	*$ -*	*$ -*	*$ -*	*$ -*	*$ 0.04*	*$ 0.26*
Pipeline Integrity - IVP	*$ -*	*$ -*	*$ 6.10*	*$ 0.18*	*$ -*	*$ -*
Pipeline Integrity (Transmission IMP)	*$ 0.53*	*$ 3.93*	*$ -*	*$ -*	*$ -*	*$ -*
Cross Bore Remediation	*$ -*	*$ 0.20*	*$ -*	*$ -*	*$ -*	*$ -*
Other Mandated	*$ -*	*$ -*	*$ 0.10*	*$ 0.03*	*$ 0.01*	*$ -*
Mandated Total	***$ 16.37***	***$ 22.11***	***$ 24.97***	***$ 19.04***	***$ 17.52***	***$ 18.16***
Damage / Failure (Reactive)						
Damage / Failure (Reactive)	***$ -***	***$ 1.61***	***$ -***	***$ -***	***$ -***	***$ -***
Remediation Projects						
Pressure Regulating Facilities - Dey St.	*$ 0.78*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Allens Avenue - Filter/Seperator	*$ 1.91*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Cumberland LNG Decommissioning	*$ 2.32*	*$ 1.78*	*$ -*	*$ -*	*$ -*	*$ -*
Remediation Projects Total	***$ 5.02***	***$ 1.78***	***$ -***	***$ -***	***$ -***	***$ -***
NON-DISCRETIONARY TOTAL	**$ 29.99**	**$ 40.08**	**$ 38.54**	**$ 35.57**	**$ 30.52**	**$ 40.42**
DISCRETIONARY						
Proactive Main Replacement & Rehabilitation						
Main Replacement (Proactive) - Leak Prone Pipe	$ 48.87	*$ 51.21*	*$ 52.63*	*$ 58.03*	*$ 60.90*	*$ 72.26*
Main Replacement (Proactive) - Large Diameter LPCI Program		*$ 1.18*		*$ 1.12*	*$ 1.42*	*$ 3.26*
Atwells Avenue				*$ 0.91*	*$ 5.61*	*$ 1.24*
Proactive Main Replacement Total	**$ 48.87**	**$ 52.38**	**$ 52.63**	**$ 60.05**	**$ 67.93**	**$ 76.77**
Proactive Service Replacement						
Proactive Service Replacement Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.24**	**$ 0.40**
Reliability						
Gas System Control	*$ -*	*$ 0.34*	*$ 0.23*	*$ 0.36*	*$ 0.02*	*$ -*
System Automation	*$ 0.73*	*$ 0.85*	*$ 0.90*	*$ 0.97*	*$ 0.97*	*$ 1.06*
Heater Installation Program	*$ 0.13*	*$ 0.11*	*$ 0.36*	*$ 0.89*	*$ 2.62*	*$ 0.87*
Wampanoag Trail & Tiverton GS - Heaters Replacement and Ownership Transfer	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 1.28*
Take Station Refurbishment	*$ -*	*$ 1.44*	*$ 0.34*	*$ 0.19*	*$ 0.41*	*$ 0.72*
Pressure Regulating Facilities	*$ 2.26*	*$ 0.91*	*$ 3.99*	*$ 1.52*	*$ 4.35*	*$ 7.51*
Allens Ave Multi Station Rebuild	*$ 2.20*	*$ 5.43*	*$ 1.61*	*$ 8.31*	*$ 9.66*	*$ 4.52*
Valve Installation/Replacement - Primary Valve Program & Aquidneck Island Low Pressure Valves	*$ 0.01*	*$ 0.01*	*$ -*	*$ 0.00*	*$ 0.16*	*$ 0.05*
Water Intrusion	*$ 0.04*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Gas System Reliability - Gas Planning	*$ 1.07*	*$ 2.23*	*$ 0.31*	*$ 0.48*	*$ 0.56*	*$ 0.41*
I&R - Reactive/CNG Programs	*$ 1.04*	*$ 1.55*	*$ 1.17*	*$ 1.19*	*$ 1.55*	*$ 2.10*
Distribution Station Over Pressure Protection	*$ -*	*$ -*	*$ -*	*$ 0.10*	*$ 1.38*	*$ 2.64*
LNG	*$ 0.41*	*$ 0.66*	*$ 0.65*	*$ 0.56*	*$ 2.64*	*$ 4.92*
Replace Pipe on Bridges	*$ -*	*$ -*	*$ -*	*$ 0.70*	*$ (0.01)*	*$ 0.16*
Access Protection Remediation	*$ -*	*$ -*	*$ 0.01*	*$ 0.02*	*$ 0.07*	*$ 0.19*
Tools & Equipment	*$ 0.52*	*$ 0.40*	*$ 0.72*	*$ 0.67*	*$ 0.48*	*$ 2.46*
Weld Shop						
Reliability Total	**$ 8.40**	**$ 13.95**	**$ 10.29**	**$ 15.93**	**$ 24.84**	**$ 28.89**
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$ 57.27**	**$ 66.33**	**$ 62.92**	**$ 75.99**	**$ 93.00**	**$ 106.05**
Southern RI Gas Expansion Project						
Pipeline	*$ -*	*$ -*	*$ 2.39*	*$ 40.18*	*$ 40.57*	*$ 13.53*
Other Upgrades/Investments	*$ -*	*$ -*	*$ -*	*$ 2.55*	*$ 0.73*	*$ 0.16*
Regulator Station Investment	*$ -*	*$ -*	*$ -*	*$ -*	*$ 0.46*	*$ 1.26*
Southern RI Gas Expansion Project Total	**$ -**	**$ -**	**$ 2.39**	**$ 42.73**	**$ 41.76**	**$ 14.95**
DISCRETIONARY TOTAL (With Gas Expansion)	**$ 57.27**	**$ 66.33**	**$ 65.31**	**$ 118.72**	**$ 134.76**	**$ 121.00**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$ 87.26**	**$ 106.41**	**$ 101.46**	**$ 111.55**	**$ 123.52**	**$ 146.46**
CAPITAL ISR TOTAL (With Gas Expansion)	**$ 87.26**	**$ 106.41**	**$ 103.85**	**$ 154.28**	**$ 165.27**	**$ 161.42**
O&M	**$ 0.49**	**$ 0.56**	**$ 0.18**	**$ -**	**$ -**	**$ -**
Notable Capital Projects Not Currently Included in the ISR						
Old Mill Lane	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 0.46*
LNG - Cumberland Tank Replacement	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 0.14*
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.60**

Division 1-50

Request:

Recalculate and provide Attachment 1, Section 4 (Pages 104 – 110) based on the CY 23 9 Month budget only.

Response:

During the preparation of this response, the Company identified a formula reference error on Page 1 of 42 of Attachment 1 of Section 3. Specifically, the "Forecasted Revenue Requirement on CY 2024 Capital Included in ISR Rate Base (12 Months)" shown on Line No. 9, column (c) was not included in the "Total Capital Investment Revenue Requirement" shown on Line No. 10, column (c). Consequently, the "Total Capital Investment Revenue Requirement" shown on Line No. 10, column (c), the "Total Capital Investment Component of Revenue Requirement" shown on Line No. 14, column (c), the "Total Revenue Requirement" shown on Line No. 15, column (c), and the "Incremental Rate Adjustment" shown on Line No. 16, column (c), were each understated by $8,660,758.

As a part of this response, the Company is including its original Section 4 (pages 104 – 110, or the rate design and bill impact analysis) updated to reflect the corrected total revenue requirement for FY 2024 (21-Month) as Attachment DIV 1-50-1. For the average residential heating customer utilizing 845 therms, the cumulative impact of the 21-Month Plan reflecting the correct revenue requirement will represent an annual increase of $122.59, or 8.1%, from current bills, as compared to an original bill impact of $105.85, or 7.0%, as originally filed with the Division.

For Section 4 (pages 104 – 110, or the rate design and bill impact analysis) based on the CY 2023 9-month revenue requirement, please see Attachment DIV 1-50-2. For the average residential heating customer utilizing 845 therms, the cumulative impact of the 9-Month Plan will represent an annual increase of $168.85, or 11.1%, from current bills.

For Section 4 (pages 104 – 110, or the rate design and bill impact analysis) based on the CY 2024 12-month revenue requirement, please see Attachment DIV 1-50-3. For the average residential heating customer utilizing 845 therms, the cumulative impact of the 12-Month Plan will represent an annual decrease of ($68.48), or -4.1%, from current bills including the impact of the CY2023 9-month plan.

	FY 2024 (21-Month) Revenue Requirement	Rate Class	Rate Base Allocator (%)	Allocation to Rate Class ($)	Throughput (dth)	ISR Factor (dth)	ISR Factor (therm)	Uncollectible %	ISR Factor (therm)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	$126,748,712								
(2)		Residential Total	66.59%	$84,401,968	30,744,949	$2.7452	$0.2745	1.91%	$0.2798
(3)		Small	8.04%	$10,190,596	3,667,874	$2.7783	$0.2778	1.91%	$0.2832
(4)		Medium	12.23%	$15,501,368	9,034,738	$1.7157	$0.1715	1.91%	$0.1748
(5)		Large LL	5.57%	$7,059,903	4,362,918	$1.6181	$0.1618	1.91%	$0.1649
(6)		Large HL	2.25%	$2,851,846	2,310,145	$1.2344	$0.1234	1.91%	$0.1258
(7)		XL-LL	0.97%	$1,229,463	1,991,070	$0.6174	$0.0617	1.91%	$0.0629
(8)		XL-HL	4.35%	$5,513,569	10,028,706	$0.5497	$0.0549	1.91%	$0.0559
(9)		Total	100.00%	$126,748,712	62,140,401				

(a) Line 1: 9 Months (Calendar Year 2023) and 12 Months (Calendar Year 2024) Revenue Requirement (Section 3: Attachment 1, Page 1, Line 14, Columns (b) and (c))
(c) Docket 4770, RI 2017 Rate Case, Compliance Attachment 14 (August 16, 2018), Schedule 2, Page 1 & 2, Line 15 (Rate Class divided by Total Company)
(d) Column (a) Line 1 * Column (c)
(e) Page 2, Column (v)
(f) Column (d) / Column (e), truncated to 4 decimal places
(g) Column (d) / (Column (e)*10), truncated to 4 decimal places
(h) Docket 4770, RI 2017 Rate Case, Compliance Attachment 2 (August 16, 2018), Schedule 22, Page 7, Line 15
(i) Column (g) / (1- Column (h)), truncated to 4 decimal places

Forecasted Throughput April 2023 - December 2024

		Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	Res-NH	32,722	17,627	14,729	12,134	11,633	11,842	14,932	23,404	34,731
(2)	Res-H	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	1,470,815	2,633,843
(3)	Small	285,844	124,997	64,421	54,187	43,242	41,803	54,616	147,547	313,165
(4)	Medium	667,083	324,894	238,769	169,312	160,551	164,298	206,272	436,093	711,633
(5)	Large LL	341,713	146,391	78,951	43,570	40,707	44,919	84,532	243,208	400,299
(6)	Large HL	130,842	106,321	90,157	86,340	80,386	86,450	87,945	108,040	131,565
(7)	X-Large LL	132,000	52,699	28,048	23,460	24,151	28,280	68,293	150,950	184,851
(8)	X-Large HL	506,318	459,948	423,059	419,512	430,465	433,813	445,403	494,428	545,481
(9)		4,413,877	2,084,669	1,512,071	1,262,205	1,224,455	1,258,101	1,560,062	3,074,485	4,955,567

		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
		(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
(1)	Res-NH	43,448	47,295	38,266	31,196	16,815	13,747	11,279	10,809	11,015
(2)	Res-H	3,549,689	3,971,935	3,065,501	2,349,331	863,518	581,746	459,826	439,149	452,699
(3)	Small	449,257	540,931	407,327	289,224	126,889	64,893	54,552	43,510	42,044
(4)	Medium	913,591	1,030,866	832,596	682,836	337,321	248,386	178,318	169,413	173,115
(5)	Large LL	512,504	555,075	433,286	345,753	148,606	79,530	43,863	40,960	45,179
(6)	Large HL	154,028	167,116	153,378	134,268	109,569	93,550	89,718	81,602	87,678
(7)	X-Large LL	222,248	205,311	171,792	133,561	53,497	28,254	23,618	24,301	28,443
(8)	X-Large HL	577,956	579,793	544,481	507,341	460,953	424,183	420,597	431,578	434,914
(9)		6,422,720	7,098,322	5,646,626	4,473,510	2,117,167	1,534,289	1,281,772	1,241,321	1,275,087

		Oct-24	Nov-24	Dec-24	Total	9-Month Calendar Year 2023	12-Month Calendar Year 2024
		(s)	(t)	(u)	(v)	(w)	(x)
(1)	Res-NH	13,974	22,390	33,227	467,216	173,753	293,462
(2)	Res-H	606,221	1,490,373	2,668,228	30,277,734	9,779,517	20,498,217
(3)	Small	54,914	148,943	315,569	3,667,874	1,129,822	2,538,052
(4)	Medium	214,908	448,585	725,898	9,034,738	3,078,905	5,955,833
(5)	Large LL	84,994	245,509	403,372	4,362,918	1,424,290	2,938,628
(6)	Large HL	89,120	109,228	132,845	2,310,145	908,045	1,402,100
(7)	X-Large LL	68,666	152,378	186,269	1,991,070	692,733	1,298,338
(8)	X-Large HL	446,472	495,427	546,583	10,028,706	4,158,428	5,870,278
(9)		1,579,269	3,112,833	5,011,991	62,140,401	21,345,492	40,794,909

Source: Company Forecast

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
21-Month (Fiscal Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

(1)						Difference due to:					
(2)	Annual	Proposed	Current				DAC				
(3)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(4)											
(5)	548	$1,126.11	$1,046.62	$79.48	7.6%	$0.00	$0.00	$77.10	$0.00	$0.00	$2.38
(6)	608	$1,229.41	$1,141.20	$88.22	7.7%	$0.00	$0.00	$85.57	$0.00	$0.00	$2.65
(7)	667	$1,330.98	$1,234.21	$96.77	7.8%	$0.00	$0.00	$93.87	$0.00	$0.00	$2.90
(8)	726	$1,432.50	$1,327.18	$105.32	7.9%	$0.00	$0.00	$102.16	$0.00	$0.00	$3.16
(9)	785	$1,533.99	$1,420.13	$113.87	8.0%	$0.00	$0.00	$110.45	$0.00	$0.00	$3.42
(10)	845	$1,637.27	$1,514.68	$122.59	8.1%	$0.00	$0.00	$118.91	$0.00	$0.00	$3.68
(11)	905	$1,740.58	$1,609.29	$131.29	8.2%	$0.00	$0.00	$127.35	$0.00	$0.00	$3.94
(12)	964	$1,842.04	$1,702.19	$139.85	8.2%	$0.00	$0.00	$135.65	$0.00	$0.00	$4.20
(13)	1,023	$1,943.62	$1,795.20	$148.42	8.3%	$0.00	$0.00	$143.97	$0.00	$0.00	$4.45
(14)	1,082	$2,045.16	$1,888.21	$156.95	8.3%	$0.00	$0.00	$152.24	$0.00	$0.00	$4.71
(15)	1,142	$2,148.43	$1,982.81	$165.62	8.4%	$0.00	$0.00	$160.65	$0.00	$0.00	$4.97

Residential Heating Low Income:

(16)						Difference due to:						
(17)	Annual	Proposed	Current				Low Income	DAC				
(18)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(19)												
(20)	548	$836.49	$776.88	$59.61	7.7%	$0.00	($19.28)	$0.00	$77.10	$0.00	$0.00	$1.79
(21)	608	$913.09	$846.93	$66.16	7.8%	$0.00	($21.39)	$0.00	$85.57	$0.00	$0.00	$1.98
(22)	667	$988.41	$915.83	$72.58	7.9%	$0.00	($23.47)	$0.00	$93.87	$0.00	$0.00	$2.18
(23)	726	$1,063.68	$984.69	$78.99	8.0%	$0.00	($25.54)	$0.00	$102.16	$0.00	$0.00	$2.37
(24)	785	$1,138.89	$1,053.49	$85.40	8.1%	$0.00	($27.61)	$0.00	$110.45	$0.00	$0.00	$2.56
(25)	845	$1,215.48	$1,123.54	$91.94	8.2%	$0.00	($29.73)	$0.00	$118.91	$0.00	$0.00	$2.76
(26)	905	$1,292.07	$1,193.60	$98.47	8.2%	$0.00	($31.84)	$0.00	$127.35	$0.00	$0.00	$2.95
(27)	964	$1,367.31	$1,262.43	$104.88	8.3%	$0.00	($33.91)	$0.00	$135.65	$0.00	$0.00	$3.15
(28)	1,023	$1,442.63	$1,331.32	$111.32	8.4%	$0.00	($35.99)	$0.00	$143.97	$0.00	$0.00	$3.34
(29)	1,082	$1,517.89	$1,400.18	$117.71	8.4%	$0.00	($38.06)	$0.00	$152.24	$0.00	$0.00	$3.53
(30)	1,142	$1,594.45	$1,470.23	$124.21	8.4%	$0.00	($40.16)	$0.00	$160.65	$0.00	$0.00	$3.73

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
RIPUC Docket No. ____
Gas Infrastructure, Safety, and Reliability Plan FY 2024
Attachment DIV 1-50-1
Page 4 of 7

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
21-Month (Fiscal Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(31)						Difference due to:					
(34)											
(35)	144	$415.56	$394.63	$20.94	5.3%	$0.00	$0.00	$20.31	$0.00	$0.00	$0.63
(36)	158	$438.16	$415.20	$22.96	5.5%	$0.00	$0.00	$22.27	$0.00	$0.00	$0.69
(37)	172	$460.80	$435.80	$25.00	5.7%	$0.00	$0.00	$24.25	$0.00	$0.00	$0.75
(38)	189	$488.21	$460.75	$27.45	6.0%	$0.00	$0.00	$26.63	$0.00	$0.00	$0.82
(39)	202	$509.22	$479.89	$29.33	6.1%	$0.00	$0.00	$28.45	$0.00	$0.00	$0.88
(40)	220	$538.28	$506.36	$31.92	6.3%	$0.00	$0.00	$30.96	$0.00	$0.00	$0.96
(41)	238	$567.35	$532.81	$34.55	6.5%	$0.00	$0.00	$33.51	$0.00	$0.00	$1.04
(42)	251	$588.35	$551.92	$36.43	6.6%	$0.00	$0.00	$35.34	$0.00	$0.00	$1.09
(43)	268	$615.79	$576.91	$38.88	6.7%	$0.00	$0.00	$37.71	$0.00	$0.00	$1.17
(44)	282	$638.42	$597.51	$40.91	6.8%	$0.00	$0.00	$39.68	$0.00	$0.00	$1.23
(45)	297	$662.66	$619.58	$43.07	7.0%	$0.00	$0.00	$41.78	$0.00	$0.00	$1.29

Residential Non-Heating Low Income:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	Low Income Discount	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(46)						Difference due to:						
(49)												
(50)	144	$309.75	$294.04	$15.70	5.3%	$0.00	($5.08)	$0.00	$20.31	$0.00	$0.00	$0.47
(51)	158	$326.51	$309.29	$17.22	5.6%	$0.00	($5.57)	$0.00	$22.27	$0.00	$0.00	$0.52
(52)	172	$343.29	$324.54	$18.75	5.8%	$0.00	($6.06)	$0.00	$24.25	$0.00	$0.00	$0.56
(53)	189	$363.64	$343.05	$20.59	6.0%	$0.00	($6.66)	$0.00	$26.63	$0.00	$0.00	$0.62
(54)	202	$379.23	$357.23	$22.00	6.2%	$0.00	($7.11)	$0.00	$28.45	$0.00	$0.00	$0.66
(55)	220	$400.76	$376.82	$23.94	6.4%	$0.00	($7.74)	$0.00	$30.96	$0.00	$0.00	$0.72
(56)	238	$422.31	$396.40	$25.91	6.5%	$0.00	($8.38)	$0.00	$33.51	$0.00	$0.00	$0.78
(57)	251	$437.89	$410.57	$27.32	6.7%	$0.00	($8.84)	$0.00	$35.34	$0.00	$0.00	$0.82
(58)	268	$458.25	$429.10	$29.16	6.8%	$0.00	($9.43)	$0.00	$37.71	$0.00	$0.00	$0.87
(59)	282	$475.03	$444.35	$30.68	6.9%	$0.00	($9.92)	$0.00	$39.68	$0.00	$0.00	$0.92
(60)	297	$493.03	$460.73	$32.30	7.0%	$0.00	($10.44)	$0.00	$41.78	$0.00	$0.00	$0.97

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
21-Month (Fiscal Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(61)											
(62)											
(63)											
(64)											
(65)	830	$1,655.15	$1,535.52	$119.63	7.8%	$0.00	$0.00	$116.04	$0.00	$0.00	$3.59
(66)	919	$1,798.35	$1,665.87	$132.47	8.0%	$0.00	$0.00	$128.50	$0.00	$0.00	$3.97
(67)	1,010	$1,944.86	$1,799.28	$145.58	8.1%	$0.00	$0.00	$141.21	$0.00	$0.00	$4.37
(68)	1,099	$2,088.15	$1,929.74	$158.41	8.2%	$0.00	$0.00	$153.66	$0.00	$0.00	$4.75
(69)	1,187	$2,229.84	$2,058.76	$171.08	8.3%	$0.00	$0.00	$165.95	$0.00	$0.00	$5.13
(70)	1,277	$2,374.66	$2,190.61	$184.04	8.4%	$0.00	$0.00	$178.52	$0.00	$0.00	$5.52
(71)	1,367	$2,519.50	$2,322.50	$197.00	8.5%	$0.00	$0.00	$191.09	$0.00	$0.00	$5.91
(72)	1,456	$2,662.79	$2,452.94	$209.86	8.6%	$0.00	$0.00	$203.56	$0.00	$0.00	$6.30
(73)	1,544	$2,804.49	$2,581.97	$222.52	8.6%	$0.00	$0.00	$215.84	$0.00	$0.00	$6.68
(74)	1,635	$2,950.98	$2,715.34	$235.64	8.7%	$0.00	$0.00	$228.57	$0.00	$0.00	$7.07
(75)	1,725	$3,095.85	$2,847.25	$248.60	8.7%	$0.00	$0.00	$241.14	$0.00	$0.00	$7.46

C & I Medium:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(76)											
(77)											
(78)											
(79)											
(80)	6,907	$10,450.61	$9,799.07	$651.55	6.6%	$0.00	$0.00	$632.00	$0.00	$0.00	$19.55
(81)	7,650	$11,460.77	$10,739.16	$721.61	6.7%	$0.00	$0.00	$699.96	$0.00	$0.00	$21.65
(82)	8,391	$12,467.77	$11,676.25	$791.52	6.8%	$0.00	$0.00	$767.77	$0.00	$0.00	$23.75
(83)	9,136	$13,480.49	$12,618.68	$861.81	6.8%	$0.00	$0.00	$835.96	$0.00	$0.00	$25.85
(84)	9,880	$14,491.89	$13,559.92	$931.97	6.9%	$0.00	$0.00	$904.01	$0.00	$0.00	$27.96
(85)	10,623	$15,502.07	$14,500.01	$1,002.05	6.9%	$0.00	$0.00	$971.99	$0.00	$0.00	$30.06
(86)	11,366	$16,512.24	$15,440.06	$1,072.18	6.9%	$0.00	$0.00	$1,040.01	$0.00	$0.00	$32.17
(87)	12,111	$17,524.97	$16,382.51	$1,142.46	7.0%	$0.00	$0.00	$1,108.19	$0.00	$0.00	$34.27
(88)	12,855	$18,536.37	$17,323.76	$1,212.62	7.0%	$0.00	$0.00	$1,176.24	$0.00	$0.00	$36.38
(89)	13,596	$19,543.37	$18,260.88	$1,282.49	7.0%	$0.00	$0.00	$1,244.02	$0.00	$0.00	$38.47
(90)	14,340	$20,554.83	$19,202.14	$1,352.69	7.0%	$0.00	$0.00	$1,312.11	$0.00	$0.00	$40.58

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
Proposed FY 2024 Gas Infrastructure, Safety and Reliability Plan
Attachment DIV 1-50-1
Page 6 of 7

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
21-Month (Fiscal Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

(91)						Difference due to:					
(92)	Annual	Proposed	Current				DAC				
(93)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(94)											
(95)	37,587	$52,503.07	$49,453.48	$3,049.60	6.2%	$0.00	$0.00	$2,958.11	$0.00	$0.00	$91.49
(96)	41,634	$57,888.24	$54,510.32	$3,377.92	6.2%	$0.00	$0.00	$3,276.58	$0.00	$0.00	$101.34
(97)	45,683	$63,276.57	$59,570.13	$3,706.44	6.2%	$0.00	$0.00	$3,595.25	$0.00	$0.00	$111.19
(98)	49,731	$68,663.63	$64,628.77	$4,034.86	6.2%	$0.00	$0.00	$3,913.81	$0.00	$0.00	$121.05
(99)	53,777	$74,047.63	$69,684.50	$4,363.13	6.3%	$0.00	$0.00	$4,232.24	$0.00	$0.00	$130.89
(100)	57,825	$79,434.71	$74,743.18	$4,691.54	6.3%	$0.00	$0.00	$4,550.79	$0.00	$0.00	$140.75
(101)	61,873	$84,821.83	$79,801.81	$5,020.02	6.3%	$0.00	$0.00	$4,869.42	$0.00	$0.00	$150.60
(102)	65,920	$90,207.04	$84,858.68	$5,348.36	6.3%	$0.00	$0.00	$5,187.91	$0.00	$0.00	$160.45
(103)	69,967	$95,592.93	$89,916.22	$5,676.70	6.3%	$0.00	$0.00	$5,506.40	$0.00	$0.00	$170.30
(104)	74,016	$100,981.15	$94,975.93	$6,005.23	6.3%	$0.00	$0.00	$5,825.07	$0.00	$0.00	$180.16
(105)	78,063	$106,366.39	$100,032.82	$6,333.57	6.3%	$0.00	$0.00	$6,143.56	$0.00	$0.00	$190.01

C & I HLF Large:

(106)						Difference due to:					
(107)	Annual	Proposed	Current				DAC				
(108)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(109)											
(110)	41,956	$49,147.29	$47,166.29	$1,981.00	4.2%	$0.00	$0.00	$1,921.57	$0.00	$0.00	$59.43
(111)	46,471	$54,169.08	$51,974.89	$2,194.20	4.2%	$0.00	$0.00	$2,128.37	$0.00	$0.00	$65.83
(112)	50,991	$59,195.83	$56,788.22	$2,407.61	4.2%	$0.00	$0.00	$2,335.38	$0.00	$0.00	$72.23
(113)	55,507	$64,218.62	$61,597.77	$2,620.85	4.3%	$0.00	$0.00	$2,542.22	$0.00	$0.00	$78.63
(114)	60,028	$69,246.48	$66,412.16	$2,834.32	4.3%	$0.00	$0.00	$2,749.29	$0.00	$0.00	$85.03
(115)	64,545	$74,270.24	$71,222.67	$3,047.58	4.3%	$0.00	$0.00	$2,956.15	$0.00	$0.00	$91.43
(116)	69,062	$79,294.04	$76,033.16	$3,260.88	4.3%	$0.00	$0.00	$3,163.05	$0.00	$0.00	$97.83
(117)	73,583	$84,321.93	$80,847.59	$3,474.34	4.3%	$0.00	$0.00	$3,370.11	$0.00	$0.00	$104.23
(118)	78,099	$89,344.68	$85,657.10	$3,687.58	4.3%	$0.00	$0.00	$3,576.95	$0.00	$0.00	$110.63
(119)	82,619	$94,371.46	$90,470.48	$3,900.98	4.3%	$0.00	$0.00	$3,783.95	$0.00	$0.00	$117.03
(120)	87,137	$99,397.24	$95,282.93	$4,114.31	4.3%	$0.00	$0.00	$3,990.88	$0.00	$0.00	$123.43

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

The Narragansett Electric Company
d/b/a Rhode Island Energy

Attachment DIV 1-50-1
Page 7 of 7

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
21-Month (Fiscal Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

	Annual	Proposed	Current				DAC	DAC			
(121)						Difference due to:					
(122)	Annual	Proposed	Current				DAC				
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(124)											
(125)	233,835	$241,247.38	$236,474.26	$4,773.12	2.0%	$0.00	$0.00	$4,629.93	$0.00	$0.00	$143.19
(126)	259,019	$266,562.17	$261,274.98	$5,287.20	2.0%	$0.00	$0.00	$5,128.58	$0.00	$0.00	$158.62
(127)	284,197	$291,871.61	$286,070.47	$5,801.13	2.0%	$0.00	$0.00	$5,627.10	$0.00	$0.00	$174.03
(128)	309,381	$317,186.43	$310,871.23	$6,315.20	2.0%	$0.00	$0.00	$6,125.74	$0.00	$0.00	$189.46
(129)	334,562	$342,498.54	$335,669.34	$6,829.20	2.0%	$0.00	$0.00	$6,624.32	$0.00	$0.00	$204.88
(130)	359,745	$367,812.48	$360,469.22	$7,343.26	2.0%	$0.00	$0.00	$7,122.96	$0.00	$0.00	$220.30
(131)	384,928	$393,126.39	$385,269.11	$7,857.29	2.0%	$0.00	$0.00	$7,621.57	$0.00	$0.00	$235.72
(132)	410,110	$418,439.42	$410,068.10	$8,371.32	2.0%	$0.00	$0.00	$8,120.18	$0.00	$0.00	$251.14
(133)	435,293	$443,753.35	$434,867.98	$8,885.37	2.0%	$0.00	$0.00	$8,618.81	$0.00	$0.00	$266.56
(134)	460,471	$469,062.76	$459,663.44	$9,399.32	2.0%	$0.00	$0.00	$9,117.34	$0.00	$0.00	$281.98
(135)	485,655	$494,377.62	$484,464.24	$9,913.38	2.0%	$0.00	$0.00	$9,615.98	$0.00	$0.00	$297.40

C & I HLF Extra-Large:

(136)						Difference due to:					
(137)	Annual	Proposed	Current				DAC				
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(139)											
(140)	486,528	$439,196.02	$426,405.81	$12,790.21	3.0%	$0.00	$0.00	$12,406.50	$0.00	$0.00	$383.71
(141)	538,924	$485,827.77	$471,660.17	$14,167.61	3.0%	$0.00	$0.00	$13,742.58	$0.00	$0.00	$425.03
(142)	591,320	$532,458.62	$516,913.63	$15,544.99	3.0%	$0.00	$0.00	$15,078.64	$0.00	$0.00	$466.35
(143)	643,718	$579,091.97	$562,169.50	$16,922.46	3.0%	$0.00	$0.00	$16,414.79	$0.00	$0.00	$507.67
(144)	696,109	$625,718.84	$607,419.05	$18,299.78	3.0%	$0.00	$0.00	$17,750.79	$0.00	$0.00	$548.99
(145)	748,506	$672,351.34	$652,674.13	$19,677.21	3.0%	$0.00	$0.00	$19,086.89	$0.00	$0.00	$590.32
(146)	800,903	$718,983.88	$697,929.19	$21,054.69	3.0%	$0.00	$0.00	$20,423.05	$0.00	$0.00	$631.64
(147)	853,294	$765,610.68	$743,178.72	$22,431.96	3.0%	$0.00	$0.00	$21,759.00	$0.00	$0.00	$672.96
(148)	905,692	$812,244.05	$788,434.63	$23,809.42	3.0%	$0.00	$0.00	$23,095.14	$0.00	$0.00	$714.28
(149)	958,088	$858,874.92	$833,688.08	$25,186.85	3.0%	$0.00	$0.00	$24,431.24	$0.00	$0.00	$755.61
(150)	1,010,485	$905,507.50	$878,943.16	$26,564.34	3.0%	$0.00	$0.00	$25,767.41	$0.00	$0.00	$796.93

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

	CY 2023 (9-Month) Revenue Requirement	Rate Class	Rate Base Allocator (%)	Allocation to Rate Class ($)	Throughput (dth)	ISR Factor (dth)	ISR Factor (therm)	Uncollectible %	ISR Factor (therm)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	$48,822,721								
(2)		Residential Total	66.59%	$32,511,050	9,953,270	$3.2663	$0.3266	1.91%	$0.3329
(3)		Small	8.04%	$3,925,347	1,129,822	$3.4743	$0.3474	1.91%	$0.3541
(4)		Medium	12.23%	$5,971,019	3,078,905	$1.9393	$0.1939	1.91%	$0.1976
(5)		Large LL	5.57%	$2,719,426	1,424,290	$1.9093	$0.1909	1.91%	$0.1946
(6)		Large HL	2.25%	$1,098,511	908,045	$1.2097	$0.1209	1.91%	$0.1232
(7)		XL-LL	0.97%	$473,580	692,733	$0.6836	$0.0683	1.91%	$0.0696
(8)		XL-HL	4.35%	$2,123,788	4,158,428	$0.5107	$0.0510	1.91%	$0.0519
(9)		Total	100.00%	$48,822,721	21,345,492				

(a) Line 1: 9 Months (Calendar Year 2023) Revenue Requirement (Section 3: Attachment 1, Page 1, Line 14, Column (b))
(c) Docket 4770, RI 2017 Rate Case, Compliance Attachment 14 (August 16, 2018), Schedule 2, Page 1 & 2, Line 15 (Rate Class divided by Total Company)
(d) Column (a) Line 1 * Column (c)
(e) Page 2, Column (w)
(f) Column (d) / Column (e), truncated to 4 decimal places
(g) Column (d) / (Column (e)*10), truncated to 4 decimal places
(h) Docket 4770, RI 2017 Rate Case, Compliance Attachment 2 (August 16, 2018), Schedule 22, Page 7, Line 15
(i) Column (g) / (1- Column (h)), truncated to 4 decimal places

The Narragansett Electric Company
d/b/a Rhode Island Energy
Proposed FY 2024 Gas Infrastructure, Safety and Reliability Plan
Attachment DIV 1-50-2
Page 1 of 7

Forecasted Throughput April 2023 - December 2024

		Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	Res-NH	32,722	17,627	14,729	12,134	11,633	11,842	14,932	23,404	34,731
(2)	Res-H	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	1,470,815	2,633,843
(3)	Small	285,844	124,997	64,421	54,187	43,242	41,803	54,616	147,547	313,165
(4)	Medium	667,083	324,894	238,769	169,312	160,551	164,298	206,272	436,093	711,633
(5)	Large LL	341,713	146,391	78,951	43,570	40,707	44,919	84,532	243,208	400,299
(6)	Large HL	130,842	106,321	90,157	86,340	80,386	86,450	87,945	108,040	131,565
(7)	X-Large LL	132,000	52,699	28,048	23,460	24,151	28,280	68,293	150,950	184,851
(8)	X-Large HL	506,318	459,948	423,059	419,512	430,465	433,813	445,403	494,428	545,481
(9)		4,413,877	2,084,669	1,512,071	1,262,205	1,224,455	1,258,101	1,560,062	3,074,485	4,955,567

		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
		(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
(1)	Res-NH	43,448	47,295	38,266	31,196	16,815	13,747	11,279	10,809	11,015
(2)	Res-H	3,549,689	3,971,935	3,065,501	2,349,331	863,518	581,746	459,826	439,149	452,699
(3)	Small	449,257	540,931	407,327	289,224	126,889	64,893	54,552	43,510	42,044
(4)	Medium	913,591	1,030,866	832,596	682,836	337,321	248,386	178,318	169,413	173,115
(5)	Large LL	512,504	555,075	433,286	345,753	148,606	79,530	43,863	40,960	45,179
(6)	Large HL	154,028	167,116	153,378	134,268	109,569	93,550	89,718	81,602	87,678
(7)	X-Large LL	222,248	205,311	171,792	133,561	53,497	28,254	23,618	24,301	28,443
(8)	X-Large HL	577,956	579,793	544,481	507,341	460,953	424,183	420,597	431,578	434,914
(9)		6,422,720	7,098,322	5,646,626	4,473,510	2,117,167	1,534,289	1,281,772	1,241,321	1,275,087

		Oct-24	Nov-24	Dec-24	Total	9-Month Calendar Year 2023	12-Month Calendar Year 2024
		(s)	(t)	(u)	(v)	(w)	(x)
(1)	Res-NH	13,974	22,390	33,227	467,216	173,753	293,462
(2)	Res-H	606,221	1,490,373	2,668,228	30,277,734	9,779,517	20,498,217
(3)	Small	54,914	148,943	315,569	3,667,874	1,129,822	2,538,052
(4)	Medium	214,908	448,585	725,898	9,034,738	3,078,905	5,955,833
(5)	Large LL	84,994	245,509	403,372	4,362,918	1,424,290	2,938,628
(6)	Large HL	89,120	109,228	132,845	2,310,145	908,045	1,402,100
(7)	X-Large LL	68,666	152,378	186,269	1,991,070	692,733	1,298,338
(8)	X-Large HL	446,472	495,427	546,583	10,028,706	4,158,428	5,870,278
(9)		1,579,269	3,112,833	5,011,991	62,140,401	21,345,492	40,794,909

Source: Company Forecast

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
9-Month (Calendar Year 2023) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(1)											
(2)											
(3)											
(4)											
(5)	548	$1,156.09	$1,046.62	$109.47	10.5%	$0.00	$0.00	$106.19	$0.00	$0.00	$3.28
(6)	608	$1,262.67	$1,141.20	$121.47	10.6%	$0.00	$0.00	$117.83	$0.00	$0.00	$3.64
(7)	667	$1,367.46	$1,234.21	$133.26	10.8%	$0.00	$0.00	$129.26	$0.00	$0.00	$4.00
(8)	726	$1,472.23	$1,327.18	$145.05	10.9%	$0.00	$0.00	$140.70	$0.00	$0.00	$4.35
(9)	785	$1,576.99	$1,420.13	$156.87	11.0%	$0.00	$0.00	$152.16	$0.00	$0.00	$4.71
(10)	845	$1,683.53	$1,514.68	$168.85	11.1%	$0.00	$0.00	$163.78	$0.00	$0.00	$5.07
(11)	905	$1,790.13	$1,609.29	$180.84	11.2%	$0.00	$0.00	$175.41	$0.00	$0.00	$5.43
(12)	964	$1,894.80	$1,702.19	$192.61	11.3%	$0.00	$0.00	$186.83	$0.00	$0.00	$5.78
(13)	1,023	$1,999.60	$1,795.20	$204.40	11.4%	$0.00	$0.00	$198.27	$0.00	$0.00	$6.13
(14)	1,082	$2,104.38	$1,888.21	$216.18	11.4%	$0.00	$0.00	$209.69	$0.00	$0.00	$6.49
(15)	1,142	$2,210.95	$1,982.81	$228.14	11.5%	$0.00	$0.00	$221.30	$0.00	$0.00	$6.84

Difference due to: GCR, DAC (Base DAC, ISR), EE, LIHEAP, GET

Residential Heating Low Income:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	Low Income Discount	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(16)												
(17)												
(18)												
(19)												
(20)	548	$858.98	$776.88	$82.11	10.6%	$0.00	($26.55)	$0.00	$106.19	$0.00	$0.00	$2.46
(21)	608	$938.04	$846.93	$91.11	10.8%	$0.00	($29.46)	$0.00	$117.83	$0.00	$0.00	$2.73
(22)	667	$1,015.77	$915.83	$99.94	10.9%	$0.00	($32.31)	$0.00	$129.26	$0.00	$0.00	$3.00
(23)	726	$1,093.48	$984.69	$108.79	11.0%	$0.00	($35.18)	$0.00	$140.70	$0.00	$0.00	$3.26
(24)	785	$1,171.14	$1,053.49	$117.65	11.2%	$0.00	($38.04)	$0.00	$152.16	$0.00	$0.00	$3.53
(25)	845	$1,250.17	$1,123.54	$126.63	11.3%	$0.00	($40.95)	$0.00	$163.78	$0.00	$0.00	$3.80
(26)	905	$1,329.23	$1,193.60	$135.63	11.4%	$0.00	($43.85)	$0.00	$175.41	$0.00	$0.00	$4.07
(27)	964	$1,406.88	$1,262.43	$144.46	11.4%	$0.00	($46.71)	$0.00	$186.83	$0.00	$0.00	$4.33
(28)	1,023	$1,484.62	$1,331.32	$153.30	11.5%	$0.00	($49.57)	$0.00	$198.27	$0.00	$0.00	$4.60
(29)	1,082	$1,562.31	$1,400.18	$162.13	11.6%	$0.00	($52.42)	$0.00	$209.69	$0.00	$0.00	$4.86
(30)	1,142	$1,641.34	$1,470.23	$171.11	11.6%	$0.00	($55.32)	$0.00	$221.30	$0.00	$0.00	$5.13

Difference due to: GCR, Low Income Discount, DAC (Base DAC, ISR), EE, LIHEAP, GET

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
9-Month (Calendar Year 2023) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

(31)						Difference due to:					
(32)	Annual	Proposed	Current				DAC				
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$423.41	$394.63	$28.78	7.3%	$0.00	$0.00	$27.92	$0.00	$0.00	$0.86
(36)	158	$446.82	$415.20	$31.62	7.6%	$0.00	$0.00	$30.67	$0.00	$0.00	$0.95
(37)	172	$470.18	$435.80	$34.38	7.9%	$0.00	$0.00	$33.35	$0.00	$0.00	$1.03
(38)	189	$498.53	$460.75	$37.77	8.2%	$0.00	$0.00	$36.64	$0.00	$0.00	$1.13
(39)	202	$520.26	$479.89	$40.37	8.4%	$0.00	$0.00	$39.16	$0.00	$0.00	$1.21
(40)	220	$550.31	$506.36	$43.95	8.7%	$0.00	$0.00	$42.63	$0.00	$0.00	$1.32
(41)	238	$580.38	$532.81	$47.58	8.9%	$0.00	$0.00	$46.15	$0.00	$0.00	$1.43
(42)	251	$602.08	$551.92	$50.16	9.1%	$0.00	$0.00	$48.66	$0.00	$0.00	$1.50
(43)	268	$630.45	$576.91	$53.54	9.3%	$0.00	$0.00	$51.93	$0.00	$0.00	$1.61
(44)	282	$653.84	$597.51	$56.33	9.4%	$0.00	$0.00	$54.64	$0.00	$0.00	$1.69
(45)	297	$678.89	$619.58	$59.31	9.6%	$0.00	$0.00	$57.53	$0.00	$0.00	$1.78

Residential Non-Heating Low Income:

(46)						Difference due to:						
(47)	Annual	Proposed	Current				Low Income	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$315.63	$294.04	$21.59	7.3%	$0.00	($6.98)	$0.00	$27.92	$0.00	$0.00	$0.65
(51)	158	$333.01	$309.29	$23.71	7.7%	$0.00	($7.67)	$0.00	$30.67	$0.00	$0.00	$0.71
(52)	172	$350.32	$324.54	$25.79	7.9%	$0.00	($8.34)	$0.00	$33.35	$0.00	$0.00	$0.77
(53)	189	$371.38	$343.05	$28.33	8.3%	$0.00	($9.16)	$0.00	$36.64	$0.00	$0.00	$0.85
(54)	202	$387.51	$357.23	$30.28	8.5%	$0.00	($9.79)	$0.00	$39.16	$0.00	$0.00	$0.91
(55)	220	$409.78	$376.82	$32.96	8.7%	$0.00	($10.66)	$0.00	$42.63	$0.00	$0.00	$0.99
(56)	238	$432.09	$396.40	$35.68	9.0%	$0.00	($11.54)	$0.00	$46.15	$0.00	$0.00	$1.07
(57)	251	$448.19	$410.57	$37.62	9.2%	$0.00	($12.17)	$0.00	$48.66	$0.00	$0.00	$1.13
(58)	268	$469.25	$429.10	$40.15	9.4%	$0.00	($12.98)	$0.00	$51.93	$0.00	$0.00	$1.20
(59)	282	$486.59	$444.35	$42.25	9.5%	$0.00	($13.66)	$0.00	$54.64	$0.00	$0.00	$1.27
(60)	297	$505.21	$460.73	$44.48	9.7%	$0.00	($14.38)	$0.00	$57.53	$0.00	$0.00	$1.33

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
9-Month (Calendar Year 2023) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

						Difference due to:					
(61)											
(62)	Annual	Proposed	Current				DAC				
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(64)											
(65)	830	$1,715.84	$1,535.52	$180.32	11.7%	$0.00	$0.00	$174.91	$0.00	$0.00	$5.41
(66)	919	$1,865.53	$1,665.87	$199.66	12.0%	$0.00	$0.00	$193.67	$0.00	$0.00	$5.99
(67)	1,010	$2,018.67	$1,799.28	$219.39	12.2%	$0.00	$0.00	$212.81	$0.00	$0.00	$6.58
(68)	1,099	$2,168.47	$1,929.74	$238.73	12.4%	$0.00	$0.00	$231.57	$0.00	$0.00	$7.16
(69)	1,187	$2,316.61	$2,058.76	$257.85	12.5%	$0.00	$0.00	$250.11	$0.00	$0.00	$7.74
(70)	1,277	$2,468.02	$2,190.61	$277.40	12.7%	$0.00	$0.00	$269.08	$0.00	$0.00	$8.32
(71)	1,367	$2,619.42	$2,322.50	$296.92	12.8%	$0.00	$0.00	$288.01	$0.00	$0.00	$8.91
(72)	1,456	$2,769.22	$2,452.94	$316.29	12.9%	$0.00	$0.00	$306.80	$0.00	$0.00	$9.49
(73)	1,544	$2,917.34	$2,581.97	$335.37	13.0%	$0.00	$0.00	$325.31	$0.00	$0.00	$10.06
(74)	1,635	$3,070.48	$2,715.34	$355.13	13.1%	$0.00	$0.00	$344.48	$0.00	$0.00	$10.65
(75)	1,725	$3,221.93	$2,847.25	$374.68	13.2%	$0.00	$0.00	$363.44	$0.00	$0.00	$11.24

C & I Medium:

						Difference due to:					
(76)											
(77)	Annual	Proposed	Current				DAC				
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(79)											
(80)	6,907	$10,612.97	$9,799.07	$813.90	8.3%	$0.00	$0.00	$789.48	$0.00	$0.00	$24.42
(81)	7,650	$11,640.61	$10,739.16	$901.45	8.4%	$0.00	$0.00	$874.41	$0.00	$0.00	$27.04
(82)	8,391	$12,664.99	$11,676.25	$988.74	8.5%	$0.00	$0.00	$959.08	$0.00	$0.00	$29.66
(83)	9,136	$13,695.22	$12,618.68	$1,076.55	8.5%	$0.00	$0.00	$1,044.25	$0.00	$0.00	$32.30
(84)	9,880	$14,724.13	$13,559.92	$1,164.21	8.6%	$0.00	$0.00	$1,129.28	$0.00	$0.00	$34.93
(85)	10,623	$15,751.75	$14,500.01	$1,251.73	8.6%	$0.00	$0.00	$1,214.18	$0.00	$0.00	$37.55
(86)	11,366	$16,779.38	$15,440.06	$1,339.32	8.7%	$0.00	$0.00	$1,299.14	$0.00	$0.00	$40.18
(87)	12,111	$17,809.64	$16,382.51	$1,427.13	8.7%	$0.00	$0.00	$1,384.32	$0.00	$0.00	$42.81
(88)	12,855	$18,838.54	$17,323.76	$1,514.78	8.7%	$0.00	$0.00	$1,469.34	$0.00	$0.00	$45.44
(89)	13,596	$19,862.94	$18,260.88	$1,602.06	8.8%	$0.00	$0.00	$1,554.00	$0.00	$0.00	$48.06
(90)	14,340	$20,891.89	$19,202.14	$1,689.75	8.8%	$0.00	$0.00	$1,639.06	$0.00	$0.00	$50.69

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
9-Month (Calendar Year 2023) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(91)											
(92)											
(93)											
(94)											
(95)	37,587	$53,653.95	$49,453.48	$4,200.47	8.5%	$0.00	$0.00	$4,074.46	$0.00	$0.00	$126.01
(96)	41,634	$59,163.02	$54,510.32	$4,652.70	8.5%	$0.00	$0.00	$4,513.12	$0.00	$0.00	$139.58
(97)	45,683	$64,675.31	$59,570.13	$5,105.19	8.6%	$0.00	$0.00	$4,952.03	$0.00	$0.00	$153.16
(98)	49,731	$70,186.32	$64,628.77	$5,557.55	8.6%	$0.00	$0.00	$5,390.82	$0.00	$0.00	$166.73
(99)	53,777	$75,694.21	$69,684.50	$6,009.71	8.6%	$0.00	$0.00	$5,829.42	$0.00	$0.00	$180.29
(100)	57,825	$81,205.25	$74,743.18	$6,462.07	8.6%	$0.00	$0.00	$6,268.21	$0.00	$0.00	$193.86
(101)	61,873	$86,716.29	$79,801.81	$6,914.47	8.7%	$0.00	$0.00	$6,707.04	$0.00	$0.00	$207.43
(102)	65,920	$92,225.40	$84,858.68	$7,366.72	8.7%	$0.00	$0.00	$7,145.72	$0.00	$0.00	$221.00
(103)	69,967	$97,735.22	$89,916.22	$7,819.00	8.7%	$0.00	$0.00	$7,584.43	$0.00	$0.00	$234.57
(104)	74,016	$103,247.42	$94,975.93	$8,271.49	8.7%	$0.00	$0.00	$8,023.35	$0.00	$0.00	$248.14
(105)	78,063	$108,756.59	$100,032.82	$8,723.76	8.7%	$0.00	$0.00	$8,462.05	$0.00	$0.00	$261.71

C & I HLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(106)											
(107)											
(108)											
(109)											
(110)	41,956	$49,034.85	$47,166.29	$1,868.56	4.0%	$0.00	$0.00	$1,812.50	$0.00	$0.00	$56.06
(111)	46,471	$54,044.54	$51,974.89	$2,069.65	4.0%	$0.00	$0.00	$2,007.56	$0.00	$0.00	$62.09
(112)	50,991	$59,059.15	$56,788.22	$2,270.93	4.0%	$0.00	$0.00	$2,202.80	$0.00	$0.00	$68.13
(113)	55,507	$64,069.83	$61,597.77	$2,472.06	4.0%	$0.00	$0.00	$2,397.90	$0.00	$0.00	$74.16
(114)	60,028	$69,085.58	$66,412.16	$2,673.42	4.0%	$0.00	$0.00	$2,593.22	$0.00	$0.00	$80.20
(115)	64,545	$74,097.24	$71,222.67	$2,874.58	4.0%	$0.00	$0.00	$2,788.34	$0.00	$0.00	$86.24
(116)	69,062	$79,108.91	$76,033.16	$3,075.75	4.0%	$0.00	$0.00	$2,983.48	$0.00	$0.00	$92.27
(117)	73,583	$84,124.69	$80,847.59	$3,277.09	4.1%	$0.00	$0.00	$3,178.78	$0.00	$0.00	$98.31
(118)	78,099	$89,135.33	$85,657.10	$3,478.23	4.1%	$0.00	$0.00	$3,373.88	$0.00	$0.00	$104.35
(119)	82,619	$94,150.03	$90,470.48	$3,679.55	4.1%	$0.00	$0.00	$3,569.16	$0.00	$0.00	$110.39
(120)	87,137	$99,163.68	$95,282.93	$3,880.74	4.1%	$0.00	$0.00	$3,764.32	$0.00	$0.00	$116.42

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
9-Month (Calendar Year 2023) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(121)											
(122)											
(123)											
(124)											
(125)	233,835	$242,862.53	$236,474.26	$6,388.27	2.7%	$0.00	$0.00	$6,196.62	$0.00	$0.00	$191.65
(126)	259,019	$268,351.30	$261,274.98	$7,076.32	2.7%	$0.00	$0.00	$6,864.03	$0.00	$0.00	$212.29
(127)	284,197	$293,834.60	$286,070.47	$7,764.12	2.7%	$0.00	$0.00	$7,531.20	$0.00	$0.00	$232.92
(128)	309,381	$319,323.39	$310,871.23	$8,452.15	2.7%	$0.00	$0.00	$8,198.59	$0.00	$0.00	$253.56
(129)	334,562	$344,809.43	$335,669.34	$9,140.09	2.7%	$0.00	$0.00	$8,865.89	$0.00	$0.00	$274.20
(130)	359,745	$370,297.34	$360,469.22	$9,828.11	2.7%	$0.00	$0.00	$9,533.27	$0.00	$0.00	$294.84
(131)	384,928	$395,785.16	$385,269.11	$10,516.05	2.7%	$0.00	$0.00	$10,200.57	$0.00	$0.00	$315.48
(132)	410,110	$421,272.14	$410,068.10	$11,204.04	2.7%	$0.00	$0.00	$10,867.92	$0.00	$0.00	$336.12
(133)	435,293	$446,760.00	$434,867.98	$11,892.02	2.7%	$0.00	$0.00	$11,535.26	$0.00	$0.00	$356.76
(134)	460,471	$472,243.33	$459,663.44	$12,579.89	2.7%	$0.00	$0.00	$12,202.49	$0.00	$0.00	$377.40
(135)	485,655	$497,732.12	$484,464.24	$13,267.88	2.7%	$0.00	$0.00	$12,869.84	$0.00	$0.00	$398.04

C & I HLF Extra-Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(136)											
(137)											
(138)											
(139)											
(140)	486,528	$437,189.71	$426,405.81	$10,783.90	2.5%	$0.00	$0.00	$10,460.38	$0.00	$0.00	$323.52
(141)	538,924	$483,605.41	$471,660.17	$11,945.25	2.5%	$0.00	$0.00	$11,586.89	$0.00	$0.00	$358.36
(142)	591,320	$530,020.20	$516,913.63	$13,106.57	2.5%	$0.00	$0.00	$12,713.37	$0.00	$0.00	$393.20
(143)	643,718	$576,437.48	$562,169.50	$14,267.98	2.5%	$0.00	$0.00	$13,839.94	$0.00	$0.00	$428.04
(144)	696,109	$622,848.26	$607,419.05	$15,429.21	2.5%	$0.00	$0.00	$14,966.33	$0.00	$0.00	$462.88
(145)	748,506	$669,264.73	$652,674.13	$16,590.60	2.5%	$0.00	$0.00	$16,092.88	$0.00	$0.00	$497.72
(146)	800,903	$715,681.18	$697,929.19	$17,751.99	2.5%	$0.00	$0.00	$17,219.43	$0.00	$0.00	$532.56
(147)	853,294	$762,091.95	$743,178.72	$18,913.23	2.5%	$0.00	$0.00	$18,345.83	$0.00	$0.00	$567.40
(148)	905,692	$808,509.23	$788,434.63	$20,074.61	2.5%	$0.00	$0.00	$19,472.37	$0.00	$0.00	$602.24
(149)	958,088	$854,924.06	$833,688.08	$21,235.98	2.5%	$0.00	$0.00	$20,598.90	$0.00	$0.00	$637.08
(150)	1,010,485	$901,340.55	$878,943.16	$22,397.39	2.5%	$0.00	$0.00	$21,725.47	$0.00	$0.00	$671.92

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022

	CY 2024 (12-Month) Revenue Requirement	Rate Class	Rate Base Allocator (%)	Allocation to Rate Class ($)	Throughput (dth)	ISR Factor (dth)	ISR Factor (therm)	Uncollectible %	ISR Factor (therm)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	$77,925,991								
(2)		Residential Total	66.59%	$51,890,917	20,791,680	$2.4957	$0.2495	1.91%	$0.2543
(3)		Small	8.04%	$6,265,250	2,538,052	$2.4685	$0.2468	1.91%	$0.2516
(4)		Medium	12.23%	$9,530,349	5,955,833	$1.6001	$0.1600	1.91%	$0.1631
(5)		Large LL	5.57%	$4,340,478	2,938,628	$1.4770	$0.1477	1.91%	$0.1505
(6)		Large HL	2.25%	$1,753,335	1,402,100	$1.2505	$0.1250	1.91%	$0.1274
(7)		XL-LL	0.97%	$755,882	1,298,338	$0.5821	$0.0582	1.91%	$0.0593
(8)		XL-HL	4.35%	$3,389,781	5,870,278	$0.5774	$0.0577	1.91%	$0.0588
(9)		Total	100.00%	$77,925,991	40,794,909	[redacted]			

(a) Line 1: 12 Months (Calendar Year 2024) Revenue Requirement (Section 3: Attachment 1, Page 1, Line 14, Column (c))
(c) Docket 4770, RI 2017 Rate Case, Compliance Attachment 14 (August 16, 2018), Schedule 2, Page 1 & 2, Line 15 (Rate Class divided by Total Company)
(d) Column (a) Line 1 * Column (c)
(e) Page 2, Column (x)
(f) Column (d) / Column (e), truncated to 4 decimal places
(g) Column (d) / (Column (e)*10), truncated to 4 decimal places
(h) Docket 4770, RI 2017 Rate Case, Compliance Attachment 2 (August 16, 2018), Schedule 22, Page 7, Line 15
(i) Column (g) / (1- Column (h)), truncated to 4 decimal places

The Narragansett Electric Company
d/b/a Rhode Island Energy
Proposed FY 2024 Gas Infrastructure, Safety and Reliability Plan
Attachment DIV 1-50-3
Page 1 of 7

Forecasted Throughput April 2023 - December 2024

		Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(1)	Res-NH	32,722	17,627	14,729	12,134	11,633	11,842	14,932	23,404	34,731	43,448	47,295	38,266
(2)	Res-H	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	1,470,815	2,633,843	3,549,689	3,971,935	3,065,501
(3)	Small	285,844	124,997	64,421	54,187	43,242	41,803	54,616	147,547	313,165	449,257	540,931	407,327
(4)	Medium	667,083	324,894	238,769	169,312	160,551	164,298	206,272	436,093	711,633	913,591	1,030,866	832,596
(5)	Large LL	341,713	146,391	78,951	43,570	40,707	44,919	84,532	243,208	400,299	512,504	555,075	433,286
(6)	Large HL	130,842	106,321	90,157	86,340	80,386	86,450	87,945	108,040	131,565	154,028	167,116	153,378
(7)	X-Large LL	132,000	52,699	28,048	23,460	24,151	28,280	68,293	150,950	184,851	222,248	205,311	171,792
(8)	X-Large HL	506,318	459,948	423,059	419,512	430,465	433,813	445,403	494,428	545,481	577,956	579,793	544,481
(9)		4,413,877	2,084,669	1,512,071	1,262,205	1,224,455	1,258,101	1,560,062	3,074,485	4,955,567	6,422,720	7,098,322	5,646,626

		Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total	9-Month Calendar Year 2023	12-Month Calendar Year 2024
		(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
(1)	Res-NH	31,196	16,815	13,747	11,279	10,809	11,015	13,974	22,390	33,227	467,216	173,753	293,462
(2)	Res-H	2,349,331	863,518	581,746	459,826	439,149	452,699	606,221	1,490,373	2,668,228	30,277,734	9,779,517	20,498,217
(3)	Small	289,224	126,889	64,893	54,552	43,510	42,044	54,914	148,943	315,569	3,667,874	1,129,822	2,538,052
(4)	Medium	682,836	337,321	248,386	178,318	169,413	173,115	214,908	448,585	725,898	9,034,738	3,078,905	5,955,833
(5)	Large LL	345,753	148,606	79,530	43,863	40,960	45,179	84,994	245,509	403,372	4,362,918	1,424,290	2,938,628
(6)	Large HL	134,268	109,569	93,550	89,718	81,602	87,678	89,120	109,228	132,845	2,310,145	908,045	1,402,100
(7)	X-Large LL	133,561	53,497	28,254	23,618	24,301	28,443	68,666	152,378	186,269	1,991,070	692,733	1,298,338
(8)	X-Large HL	507,341	460,953	424,183	420,597	431,578	434,914	446,472	495,427	546,583	10,028,706	4,158,428	5,870,278
(9)		4,473,510	2,117,167	1,534,289	1,281,772	1,241,321	1,275,087	1,579,269	3,112,833	5,011,991	62,140,401	21,345,492	40,794,909

Source: Company Forecast

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
12-Month (Calendar Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(1)											
(2)											
(3)											
(4)											
(5)	548	$1,111.69	$1,156.09	($44.40)	-3.8%	$0.00	$0.00	($43.07)	$0.00	$0.00	($1.33)
(6)	608	$1,213.41	$1,262.67	($49.26)	-3.9%	$0.00	$0.00	($47.78)	$0.00	$0.00	($1.48)
(7)	667	$1,313.40	$1,367.46	($54.06)	-4.0%	$0.00	$0.00	($52.44)	$0.00	$0.00	($1.62)
(8)	726	$1,413.39	$1,472.23	($58.85)	-4.0%	$0.00	$0.00	($57.08)	$0.00	$0.00	($1.77)
(9)	785	$1,513.35	$1,576.99	($63.64)	-4.0%	$0.00	$0.00	($61.73)	$0.00	$0.00	($1.91)
(10)	845	$1,615.04	$1,683.53	($68.48)	-4.1%	$0.00	$0.00	($66.43)	$0.00	$0.00	($2.05)
(11)	905	$1,716.79	$1,790.13	($73.34)	-4.1%	$0.00	$0.00	($71.14)	$0.00	$0.00	($2.20)
(12)	964	$1,816.70	$1,894.80	($78.10)	-4.1%	$0.00	$0.00	($75.76)	$0.00	$0.00	($2.34)
(13)	1,023	$1,916.71	$1,999.60	($82.90)	-4.1%	$0.00	$0.00	($80.41)	$0.00	$0.00	($2.49)
(14)	1,082	$2,016.69	$2,104.38	($87.69)	-4.2%	$0.00	$0.00	($85.06)	$0.00	$0.00	($2.63)
(15)	1,142	$2,118.41	$2,210.95	($92.55)	-4.2%	$0.00	$0.00	($89.77)	$0.00	$0.00	($2.78)

Residential Heating Low Income:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	Low Income Discount	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(16)												
(17)												
(18)												
(19)												
(20)	548	$825.68	$858.98	($33.30)	-3.9%	$0.00	$10.77	$0.00	($43.07)	$0.00	$0.00	($1.00)
(21)	608	$901.09	$938.04	($36.94)	-3.9%	$0.00	$11.95	$0.00	($47.78)	$0.00	$0.00	($1.11)
(22)	667	$975.22	$1,015.77	($40.55)	-4.0%	$0.00	$13.11	$0.00	($52.44)	$0.00	$0.00	($1.22)
(23)	726	$1,049.35	$1,093.48	($44.13)	-4.0%	$0.00	$14.27	$0.00	($57.08)	$0.00	$0.00	($1.32)
(24)	785	$1,123.41	$1,171.14	($47.73)	-4.1%	$0.00	$15.43	$0.00	($61.73)	$0.00	$0.00	($1.43)
(25)	845	$1,198.81	$1,250.17	($51.36)	-4.1%	$0.00	$16.61	$0.00	($66.43)	$0.00	$0.00	($1.54)
(26)	905	$1,274.22	$1,329.23	($55.01)	-4.1%	$0.00	$17.79	$0.00	($71.14)	$0.00	$0.00	($1.65)
(27)	964	$1,348.31	$1,406.88	($58.58)	-4.2%	$0.00	$18.94	$0.00	($75.76)	$0.00	$0.00	($1.76)
(28)	1,023	$1,422.44	$1,484.62	($62.17)	-4.2%	$0.00	$20.10	$0.00	($80.41)	$0.00	$0.00	($1.87)
(29)	1,082	$1,496.55	$1,562.31	($65.77)	-4.2%	$0.00	$21.27	$0.00	($85.06)	$0.00	$0.00	($1.97)
(30)	1,142	$1,571.93	$1,641.34	($69.41)	-4.2%	$0.00	$22.44	$0.00	($89.77)	$0.00	$0.00	($2.08)

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022, including the CY 2023 (9-Month) Gas ISR rate.

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
12-Month (Calendar Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

						Difference due to:					
(31)											
(32)	Annual	Proposed	Current				DAC				
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$411.75	$423.41	($11.66)	-2.8%	$0.00	$0.00	($11.31)	$0.00	$0.00	($0.35)
(36)	158	$434.00	$446.82	($12.81)	-2.9%	$0.00	$0.00	($12.43)	$0.00	$0.00	($0.38)
(37)	172	$456.24	$470.18	($13.94)	-3.0%	$0.00	$0.00	($13.52)	$0.00	$0.00	($0.42)
(38)	189	$483.19	$498.53	($15.34)	-3.1%	$0.00	$0.00	($14.88)	$0.00	$0.00	($0.46)
(39)	202	$503.88	$520.26	($16.38)	-3.1%	$0.00	$0.00	($15.89)	$0.00	$0.00	($0.49)
(40)	220	$532.47	$550.31	($17.84)	-3.2%	$0.00	$0.00	($17.30)	$0.00	$0.00	($0.54)
(41)	238	$561.08	$580.38	($19.30)	-3.3%	$0.00	$0.00	($18.72)	$0.00	$0.00	($0.58)
(42)	251	$581.74	$602.08	($20.34)	-3.4%	$0.00	$0.00	($19.73)	$0.00	$0.00	($0.61)
(43)	268	$608.74	$630.45	($21.71)	-3.4%	$0.00	$0.00	($21.06)	$0.00	$0.00	($0.65)
(44)	282	$630.99	$653.84	($22.86)	-3.5%	$0.00	$0.00	($22.17)	$0.00	$0.00	($0.69)
(45)	297	$654.83	$678.89	($24.06)	-3.5%	$0.00	$0.00	($23.34)	$0.00	$0.00	($0.72)

Residential Non-Heating Low Income:

						Difference due to:						
(46)												
(47)	Annual	Proposed	Current				Low Income	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$306.89	$315.63	($8.74)	-2.8%	$0.00	$2.83	$0.00	($11.31)	$0.00	$0.00	($0.26)
(51)	158	$323.40	$333.01	($9.61)	-2.9%	$0.00	$3.11	$0.00	($12.43)	$0.00	$0.00	($0.29)
(52)	172	$339.87	$350.32	($10.45)	-3.0%	$0.00	$3.38	$0.00	($13.52)	$0.00	$0.00	($0.31)
(53)	189	$359.88	$371.38	($11.51)	-3.1%	$0.00	$3.72	$0.00	($14.88)	$0.00	$0.00	($0.35)
(54)	202	$375.22	$387.51	($12.29)	-3.2%	$0.00	$3.97	$0.00	($15.89)	$0.00	$0.00	($0.37)
(55)	220	$396.40	$409.78	($13.38)	-3.3%	$0.00	$4.32	$0.00	($17.30)	$0.00	$0.00	($0.40)
(56)	238	$417.61	$432.09	($14.47)	-3.3%	$0.00	$4.68	$0.00	($18.72)	$0.00	$0.00	($0.43)
(57)	251	$432.94	$448.19	($15.26)	-3.4%	$0.00	$4.93	$0.00	($19.73)	$0.00	$0.00	($0.46)
(58)	268	$452.97	$469.25	($16.28)	-3.5%	$0.00	$5.27	$0.00	($21.06)	$0.00	$0.00	($0.49)
(59)	282	$469.45	$486.59	($17.14)	-3.5%	$0.00	$5.54	$0.00	($22.17)	$0.00	$0.00	($0.51)
(60)	297	$487.16	$505.21	($18.05)	-3.6%	$0.00	$5.84	$0.00	($23.34)	$0.00	$0.00	($0.54)

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022, including the CY 2023 (9-Month) Gas ISR rate.

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
12-Month (Calendar Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(61)											
(62)											
(63)											
(64)											
(65)	830	$1,628.11	$1,715.84	($87.73)	-5.1%	$0.00	$0.00	($85.10)	$0.00	$0.00	($2.63)
(66)	919	$1,768.43	$1,865.53	($97.10)	-5.2%	$0.00	$0.00	($94.19)	$0.00	$0.00	($2.91)
(67)	1,010	$1,911.93	$2,018.67	($106.74)	-5.3%	$0.00	$0.00	($103.54)	$0.00	$0.00	($3.20)
(68)	1,099	$2,052.36	$2,168.47	($116.11)	-5.4%	$0.00	$0.00	($112.63)	$0.00	$0.00	($3.48)
(69)	1,187	$2,191.18	$2,316.61	($125.42)	-5.4%	$0.00	$0.00	($121.66)	$0.00	$0.00	($3.76)
(70)	1,277	$2,333.07	$2,468.02	($134.95)	-5.5%	$0.00	$0.00	($130.90)	$0.00	$0.00	($4.05)
(71)	1,367	$2,474.95	$2,619.42	($144.46)	-5.5%	$0.00	$0.00	($140.13)	$0.00	$0.00	($4.33)
(72)	1,456	$2,615.35	$2,769.22	($153.88)	-5.6%	$0.00	$0.00	($149.26)	$0.00	$0.00	($4.62)
(73)	1,544	$2,754.20	$2,917.34	($163.14)	-5.6%	$0.00	$0.00	($158.25)	$0.00	$0.00	($4.89)
(74)	1,635	$2,897.72	$3,070.48	($172.75)	-5.6%	$0.00	$0.00	($167.57)	$0.00	$0.00	($5.18)
(75)	1,725	$3,039.66	$3,221.93	($182.27)	-5.7%	$0.00	$0.00	($176.80)	$0.00	$0.00	($5.47)

C & I Medium:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(76)											
(77)											
(78)											
(79)											
(80)	6,907	$10,367.29	$10,612.97	($245.67)	-2.3%	$0.00	$0.00	($238.30)	$0.00	$0.00	($7.37)
(81)	7,650	$11,368.52	$11,640.61	($272.09)	-2.3%	$0.00	$0.00	($263.93)	$0.00	$0.00	($8.16)
(82)	8,391	$12,366.55	$12,664.99	($298.44)	-2.4%	$0.00	$0.00	($289.49)	$0.00	$0.00	($8.95)
(83)	9,136	$13,370.27	$13,695.22	($324.95)	-2.4%	$0.00	$0.00	($315.20)	$0.00	$0.00	($9.75)
(84)	9,880	$14,372.74	$14,724.13	($351.39)	-2.4%	$0.00	$0.00	($340.85)	$0.00	$0.00	($10.54)
(85)	10,623	$15,373.93	$15,751.75	($377.81)	-2.4%	$0.00	$0.00	($366.48)	$0.00	$0.00	($11.33)
(86)	11,366	$16,375.13	$16,779.38	($404.25)	-2.4%	$0.00	$0.00	($392.12)	$0.00	$0.00	($12.13)
(87)	12,111	$17,378.89	$17,809.64	($430.75)	-2.4%	$0.00	$0.00	($417.83)	$0.00	$0.00	($12.92)
(88)	12,855	$18,381.31	$18,838.54	($457.23)	-2.4%	$0.00	$0.00	($443.51)	$0.00	$0.00	($13.72)
(89)	13,596	$19,379.38	$19,862.94	($483.56)	-2.4%	$0.00	$0.00	($469.05)	$0.00	$0.00	($14.51)
(90)	14,340	$20,381.87	$20,891.89	($510.02)	-2.4%	$0.00	$0.00	($494.72)	$0.00	$0.00	($15.30)

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022, including the CY 2023 (9-Month) Gas ISR rate.

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
12-Month (Calendar Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

(91)						Difference due to:					
(92)	Annual	Proposed	Current				DAC				
(93)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(94)											
(95)	37,587	$51,945.07	$53,653.95	($1,708.88)	-3.2%	$0.00	$0.00	($1,657.61)	$0.00	$0.00	($51.27)
(96)	41,634	$57,270.19	$59,163.02	($1,892.84)	-3.2%	$0.00	$0.00	($1,836.05)	$0.00	$0.00	($56.79)
(97)	45,683	$62,598.38	$64,675.31	($2,076.93)	-3.2%	$0.00	$0.00	($2,014.62)	$0.00	$0.00	($62.31)
(98)	49,731	$67,925.37	$70,186.32	($2,260.95)	-3.2%	$0.00	$0.00	($2,193.12)	$0.00	$0.00	($67.83)
(99)	53,777	$73,249.29	$75,694.21	($2,444.92)	-3.2%	$0.00	$0.00	($2,371.57)	$0.00	$0.00	($73.35)
(100)	57,825	$78,576.30	$81,205.25	($2,628.95)	-3.2%	$0.00	$0.00	($2,550.08)	$0.00	$0.00	($78.87)
(101)	61,873	$83,903.31	$86,716.29	($2,812.98)	-3.2%	$0.00	$0.00	($2,728.59)	$0.00	$0.00	($84.39)
(102)	65,920	$89,228.42	$92,225.40	($2,996.98)	-3.2%	$0.00	$0.00	($2,907.07)	$0.00	$0.00	($89.91)
(103)	69,967	$94,554.22	$97,735.22	($3,181.00)	-3.3%	$0.00	$0.00	($3,085.57)	$0.00	$0.00	($95.43)
(104)	74,016	$99,882.37	$103,247.42	($3,365.05)	-3.3%	$0.00	$0.00	($3,264.10)	$0.00	$0.00	($100.95)
(105)	78,063	$105,207.52	$108,756.59	($3,549.06)	-3.3%	$0.00	$0.00	($3,442.59)	$0.00	$0.00	($106.47)

C & I HLF Large:

(106)						Difference due to:					
(107)	Annual	Proposed	Current				DAC				
(108)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(109)											
(110)	41,956	$49,216.52	$49,034.85	$181.67	0.4%	$0.00	$0.00	$176.22	$0.00	$0.00	$5.45
(111)	46,471	$54,245.74	$54,044.54	$201.21	0.4%	$0.00	$0.00	$195.17	$0.00	$0.00	$6.04
(112)	50,991	$59,279.93	$59,059.15	$220.78	0.4%	$0.00	$0.00	$214.16	$0.00	$0.00	$6.62
(113)	55,507	$64,310.16	$64,069.83	$240.33	0.4%	$0.00	$0.00	$233.12	$0.00	$0.00	$7.21
(114)	60,028	$69,345.47	$69,085.58	$259.89	0.4%	$0.00	$0.00	$252.09	$0.00	$0.00	$7.80
(115)	64,545	$74,376.73	$74,097.24	$279.48	0.4%	$0.00	$0.00	$271.10	$0.00	$0.00	$8.38
(116)	69,062	$79,407.93	$79,108.91	$299.02	0.4%	$0.00	$0.00	$290.05	$0.00	$0.00	$8.97
(117)	73,583	$84,443.31	$84,124.69	$318.63	0.4%	$0.00	$0.00	$309.07	$0.00	$0.00	$9.56
(118)	78,099	$89,473.49	$89,135.33	$338.16	0.4%	$0.00	$0.00	$328.02	$0.00	$0.00	$10.14
(119)	82,619	$94,507.72	$94,150.03	$357.69	0.4%	$0.00	$0.00	$346.96	$0.00	$0.00	$10.73
(120)	87,137	$99,540.97	$99,163.68	$377.29	0.4%	$0.00	$0.00	$365.97	$0.00	$0.00	$11.32

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022, including the CY 2023 (9-Month) Gas ISR rate.

Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
12-Month (Calendar Year 2024) Revenue Requirement
Annual Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

						Difference due to:					
(121)							DAC				
(122)	Annual	Proposed	Current								
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(124)											
(125)	233,835	$240,379.53	$242,862.53	($2,483.00)	-1.0%	$0.00	$0.00	($2,408.51)	$0.00	$0.00	($74.49)
(126)	259,019	$265,600.86	$268,351.30	($2,750.43)	-1.0%	$0.00	$0.00	($2,667.92)	$0.00	$0.00	($82.51)
(127)	284,197	$290,816.85	$293,834.60	($3,017.74)	-1.0%	$0.00	$0.00	($2,927.21)	$0.00	$0.00	($90.53)
(128)	309,381	$316,038.21	$319,323.39	($3,285.18)	-1.0%	$0.00	$0.00	($3,186.62)	$0.00	$0.00	($98.56)
(129)	334,562	$341,256.87	$344,809.43	($3,552.57)	-1.0%	$0.00	$0.00	($3,445.99)	$0.00	$0.00	($106.58)
(130)	359,745	$366,477.35	$370,297.34	($3,819.99)	-1.0%	$0.00	$0.00	($3,705.39)	$0.00	$0.00	($114.60)
(131)	384,928	$391,697.80	$395,785.16	($4,087.36)	-1.0%	$0.00	$0.00	($3,964.74)	$0.00	$0.00	($122.62)
(132)	410,110	$416,917.37	$421,272.14	($4,354.77)	-1.0%	$0.00	$0.00	($4,224.13)	$0.00	$0.00	($130.64)
(133)	435,293	$442,137.83	$446,760.00	($4,622.18)	-1.0%	$0.00	$0.00	($4,483.51)	$0.00	$0.00	($138.67)
(134)	460,471	$467,353.77	$472,243.33	($4,889.56)	-1.0%	$0.00	$0.00	($4,742.87)	$0.00	$0.00	($146.69)
(135)	485,655	$492,575.16	$497,732.12	($5,156.96)	-1.0%	$0.00	$0.00	($5,002.25)	$0.00	$0.00	($154.71)

C & I HLF Extra-Large:

						Difference due to:					
(136)							DAC				
(137)	Annual	Proposed	Current								
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(139)											
(140)	486,528	$440,650.60	$437,189.71	$3,460.89	0.8%	$0.00	$0.00	$3,357.06	$0.00	$0.00	$103.83
(141)	538,924	$487,438.97	$483,605.41	$3,833.56	0.8%	$0.00	$0.00	$3,718.55	$0.00	$0.00	$115.01
(142)	591,320	$534,226.49	$530,020.20	$4,206.30	0.8%	$0.00	$0.00	$4,080.11	$0.00	$0.00	$126.19
(143)	643,718	$581,016.50	$576,437.48	$4,579.02	0.8%	$0.00	$0.00	$4,441.65	$0.00	$0.00	$137.37
(144)	696,109	$627,799.98	$622,848.26	$4,951.72	0.8%	$0.00	$0.00	$4,803.17	$0.00	$0.00	$148.55
(145)	748,506	$674,589.14	$669,264.73	$5,324.41	0.8%	$0.00	$0.00	$5,164.68	$0.00	$0.00	$159.73
(146)	800,903	$721,378.32	$715,681.18	$5,697.14	0.8%	$0.00	$0.00	$5,526.23	$0.00	$0.00	$170.91
(147)	853,294	$768,161.76	$762,091.95	$6,069.81	0.8%	$0.00	$0.00	$5,887.72	$0.00	$0.00	$182.09
(148)	905,692	$814,951.78	$808,509.23	$6,442.55	0.8%	$0.00	$0.00	$6,249.27	$0.00	$0.00	$193.28
(149)	958,088	$861,739.33	$854,924.06	$6,815.27	0.8%	$0.00	$0.00	$6,610.81	$0.00	$0.00	$204.46
(150)	1,010,485	$908,528.52	$901,340.55	$7,187.97	0.8%	$0.00	$0.00	$6,972.33	$0.00	$0.00	$215.64

Note: Bill Impacts are based on rates approved and currently in effect as of May 1, 2022, including the CY 2023 (9-Month) Gas ISR rate.

Division 1-51

Request:

Provide the PowerPoint Presentations from the November 1 and 2, 2022 Walkthroughs in electronic format.

Response:

Please see Attachment DIV 1-51 for a copy of the PowerPoint Presentations from the November 1, 2022, and November 2, 2022 Walkthroughs. See page 48 of the slide deck presentation for a list of minor edits made to the presentation on November 3, 2022 (after the Walkthroughs).

Gas ISR
21-Month Plan Proposal
RIE/Division Walkthrough
November 1-2, 2022

Cleanup edits made on 11/3/2022
- See page 48 (last page) for list of edits

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Agenda - Tuesday

Rhode Island Energy™

Categories	Leadership Team	Day/Slot	Time Range	Allotment
LNG	Brian Kirkwood, Julie Porcaro, Jeff Montigny, Tom Mulkeen, Bao Hang, Mahadevan Venitachalam	Tues - PM	1:00-2:30	90
Break			2:30-2:45	
I&R - Reactive	Michael Romano, Julie Porcaro, Lauren MacLean	Tues - PM	2:45-3:00	15
Tools & Equipment	Mark Lucchetti, Joe Curley, Lauren MacLean, Andrew Conlon, Lae Hunt, Jer Kue, David Gavula	Tues - PM	3:00-3:15	15
Weld Shop	Ashley Buccheri, Joe Curley David Gavula	Tues - PM	3:15-3:30	15
End Day - Tuesday				

Agenda – Wednesday AM

Categories	Leadership Team	Day/Slot	Time Range	Allotment
Corrosion	Butch Vincent, Gene Au, May Zhen, Lae Hunt, Lauren MacLean	Wed - AM	8:10-8:20	10
Replace Pipe on Bridges	Gene Au, Barry Foster, Lae Hunt	Wed - AM	8:20-8:30	10
Access Protection Remediation	Gene Au, Barry Foster, Bao Hang	Wed - AM	8:30-8:35	5
Valve Installation/Replacement - Primary Valve Program & Aquidneck Island Low Pressure Valves	Brandon Flynn, Lae Hunt, Lauren MacLean	Wed - AM	8:35-8:40	5
Low Pressure System Elimination (Proactive)	Brandon Flynn, Barry Foster, Corey Hogg, Lae Hunt, Jessika Soto	Wed - AM	8:40-8:50	10
Gas System Reliability	Brandon Flynn, Lae Hunt, Jessika Soto, Agnieszka Przybysz	Wed - AM	8:50-9:00	10
Break			9:00-9:10	10
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	9:10-9:30	20
Service Replacements (Reactive) - Non-Leaks/Other	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	9:30-9:40	10
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	9:40-9:55	15
CSC/Public Works - Non-Reimbursable	Lae Hunt, Barry Foster, Jim Paulette, May Zhen, Chelsea Tervo, Jessika Soto	Wed - AM	9:55-10:25	20
CSC/Public Works - Reimbursable		Wed - AM		5
CSC/Public Works - Reimbursements		Wed - AM		5
Main Replacement (Proactive) - Leak Prone Pipe	Corey Hogg, Barry Foster, Jessika Soto, Phil LaFond	Wed - AM	10:25-11:00	35
Break			11:00-11:10	10
Atwells Avenue	Corey Hogg, Barry Foster	Wed - AM	11:10-11:20	10
Main Replacement (Proactive) - Large Diameter LPCI Program (CI Lining, CISBOT)	Corey Hogg, Barry Foster, Lauren MacLean	Wed - AM	11:20-11:30	10
Proactive Service Replacement	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	11:30-11:45	15
Purchase Meters (Replacement)	Andrew Conlon, Lae Hunt, Jer Kue	Wed - AM	11:45-12:00	15
Lunch			12:00-1:00	60

Agenda – Wednesday - PM

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Categories	Leadership Team	Day/Slot	Time Range	Allotment
Lunch			12:00-1:00	60
Wampanoag Trail & Tiverton GS - Heaters Replacement and Ownership Transfer	Justin Zaccari, Lae Hunt, Phil DeMelo, Lauren MacLean	Wed - PM	1:00-1:10	10
Transmission Station Integrity	Justin Zaccari, Tom Mulkeen, Bao Hang, Agnieszka Przybysz	Wed - PM	1:10-1:40	30
Pipeline Integrity - IVP - Wampanoag Trail Pipeline Replacement	Tom Mulkeen, Lae Hunt, Bao Hang	Wed - PM	1:40-1:50	10
System Automation	Justin Zaccari, Tom Mulkeen, Lauren MacLean	Wed - PM	1:50-2:00	10
Heater Installation Program	Justin Zaccari, Tom Mulkeen, Luke MacDonald, Bao Hang	Wed - PM	2:00-2:15	15
Take Station Refurbishment	Justin Zaccari, Tom Mulkeen, Lae Hunt, Lauren MacLean	Wed - PM	2:15-2:25	10
Break			2:25-2:35	10
Pressure Regulating Facilities	Justin Zaccari, Tom Mulkeen, Lauren MacLean	Wed - PM	2:35-2:50	15
Distribution Station Over Pressure Protection	Justin Zaccari, Tom Mulkeen, Lauren MacLean	Wed - PM	2:50-3:05	15
Pipeline	Tom Mulkeen, Lae Hunt, Bao Hang, Agnieszka Przybysz, Andrew Hogan	Wed - PM	3:05-3:20	15
Other Upgrades/Investments		Wed - PM		
Regulator Station Investment		Wed - PM		

LNG

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
LNG	$10,089	$15,880	$17,457	$42,977	$60,434	Brian Kirkwood, Julie Porcaro, Jeff Montigny, Tom Mulkeen, Bao Hang, Mahadevan Venitachalam

4 primary sites will be addressed by this program during the 21-month period

- Newport Navy Yard
- Cumberland
- Exeter
- Old Mill Lane (existing site)

- Newport Navy Yard Site – Decommission the LNG site
  - CY23: $0.23M
  - CY24: $2.50M

LNG - Cumberland

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- Cumberland – $7.00M Portable LNG Equipment being purchased in FY23, will be placed in-service in CY23.
- Ongoing investments at Cumberland are considering future flexibility
  - Support current operations, support operations during potential tank rebuild, minimize stranded costs if tank is rebuilt
- 21-Month activities include
  - Supplemental Portable Storage – CY23: $0.88M, CY24: $2.63M
    - Doubles site's storage capacity, increase run time from 5 to 10 hours. Enhances the reliable operation of site, especially during inclement weather (may not be prudent to have LNG tanker trucks on roadway)
  - LNG Water Main – CY23: $0.75M
  - Boil-off Gas ("BOG") Recovery Manifold – CY23: $0.25M – Supports Act on Climate
  - Portable Vaporizer Tap – CY23: $0.40M

LNG - Exeter

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- **Exeter** – Hi-Ex Foam System Install and ongoing Boil-off Compressors upgrade are the primary FY23 activities
- Site is critical to support gas operations in southern RI
- 21-Month activities include
  - Boil-off Compressors Upgrade – CY23: $9.00M, CY24: $6.08M – In-service CY24: $18.50M
  - Septic Upgrade – CY23: $0.88M
  - Emergency Generator Upgrade & Uninterruptable Power Supply – CY23: $0.08M, CY24: $0.70M
    - Supports new boil-off compressors
  - Tank Switchback Stairs – CY23: $0.33M, CY24: $3.00M
    - Access top of LNG Tank – Improve safety, Improves access for tank maintenance
  - Control Room Upgrade – CY23: $0.89M, CY24: $8.00M
    - Primary spend is the piping and controls. Current room is outdated and abuts stations main electrical room
  - HMI Hardware & Software Upgrade – CY23: $0.03M, CY24: $0.25M
    - Require upgrade every five years or so
  - LNG Truck Station – CY23: $0.40M, CY24: $10.00M
    - Adds multiple layers of safety, improve LNG delivery process, and will incorporate a plantwide AESD system.

LNG – Old Mill Lane

- Old Mill Lane – FY23 Activities include improvements to existing site footprint
  - Install of Ecoraster – Meets State of RI storm water standards for the site. Will also eliminate time to install original type of matting used at the site in the Fall, followed by its' removal in the Spring. Provides a strong surface for movement of trucks and equipment on the site, which will be ready for use at any time of the year as required.
- Site is currently topic of EFSB approval process
  - A decision is expected by July 2023
- 21-Month activities include
  - Portable LNG Equipment Purchase – CY23: $2.51M, CY24: $9.00M – In-service CY25: $11.51M
    - Very similar to the equipment purchase/transition ongoing at Cumberland LNG. Company will purchase and operate their own equipment rather than renewing a rental agreement for the portable equipment and its operation.
    - Will result in shift of costs as current leasing costs are paid through the Gas Cost Recovery factor and the cost of this equipment purchase will now flow through the Gas ISR.
    - Company anticipates investment will be recouped over 10 years of operation, but could be shorter payback period.

LNG

- Original Surface Matting requiring annual Fall install & Spring removal

LNG

- New Ecoraster Product Recently Installed

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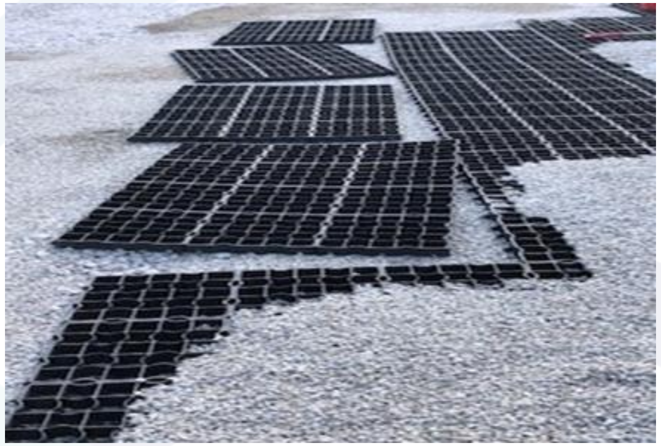

Instrumentation and Regulation (I&R) Reactive

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
I&R - Reactive	$1,375	$1,375	$1,052	$1,423	$2,475	Michael Romano, Julie Porcaro, Lauren MacLean

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Program Summary

- Purpose: Established to address capital project requirements over and above the Pressure Regulation capital budget
  - Projects range from instrumentation replacement due to failure; Replacement of obsolete/unreliable equipment, such as regulators, pilots, boilers, heat exchangers, odorant equipment, and station valves;

Tools & Equipment

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Tools & Equipment	$824	$1,687	$1,233	$913	$2,146	Mark Lucchetti, Joe Curley, Lauren MacLean, Andrew Conlon, Lae Hunt, Jer Kue, David Gavula

Program Summary

- Purpose: Tools & Equipment to support work contained in the Gas ISR and provide for the safety and reliability of gas distribution system

- These tools and equipment purchases will enhance the safety and efficiency of capital projects. Some planned key purchases include:
  - 4 Ground Penetrating Radar Systems (“GPRS”) – helps locate underground utilities
  - 1 T.D. Williamson ProStopp – critical tool used to isolate a segment of pipe

Weld Shop

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Weld Shop	$0	$0	$5,000	$0	$5,000	Ashley Buccheri, Joe Curley David Gavula

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- Purpose: Category is to fund the purchase of welding tools and equipment to support capital projects within the ISR program and a weld shop to house the tools, equipment, welding stock, and perform welding activities.
  - Buildout of a new consolidated weld shop will maximize efficiency by bringing all internal welding resources to a modern and centralized location instead of having 2 locations. The additional workspace/bays will allow more welding activities to occur simultaneously.
    - Company hired 2 additional internal welders, for total of 6 in-house resources
  - Larger footprint/size of the weld shop will enable larger welding fabrications to be done in-house – currently often outsourced – can lead to delays completing stages of a project because of extra time (coordination, transportation of materials, contractor availability, etc)

Agenda – Wednesday AM

Categories	Leadership Team	Day/Slot	Time Range	Allotment
Corrosion	Butch Vincent, Gene Au, May Zhen, Lae Hunt, Lauren MacLean	Wed - AM	8:10-8:20	10
Replace Pipe on Bridges	Gene Au, Barry Foster, Lae Hunt	Wed - AM	8:20-8:30	10
Access Protection Remediation	Gene Au, Barry Foster, Bao Hang	Wed - AM	8:30-8:35	5
Valve Installation/Replacement - Primary Valve Program & Aquidneck Island Low Pressure Valves	Brandon Flynn, Lae Hunt, Lauren MacLean	Wed - AM	8:35-8:40	5
Low Pressure System Elimination (Proactive)	Brandon Flynn, Barry Foster, Corey Hogg, Lae Hunt, Jessika Soto	Wed - AM	8:40-8:50	10
Gas System Reliability	Brandon Flynn, Lae Hunt, Jessika Soto, Agnieszka Przybysz	Wed - AM	8:50-9:00	10
Break			9:00-9:10	10
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	9:10-9:30	20
Service Replacements (Reactive) - Non-Leaks/Other	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	9:30-9:40	10
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	9:40-9:55	15
CSC/Public Works - Non-Reimbursable	Lae Hunt, Barry Foster, Jim Paulette, May Zhen, Chelsea Tervo, Jessika Soto	Wed - AM	9:55-10:25	20
CSC/Public Works - Reimbursable		Wed - AM		5
CSC/Public Works - Reimbursements		Wed - AM		5
Main Replacement (Proactive) - Leak Prone Pipe	Corey Hogg, Barry Foster, Jessika Soto, Phil LaFond	Wed - AM	10:25-11:00	35
Break			11:00-11:10	10
Atwells Avenue	Corey Hogg, Barry Foster	Wed - AM	11:10-11:20	10
Main Replacement (Proactive) - Large Diameter LPCI Program (CI Lining, CISBOT)	Corey Hogg, Barry Foster, Lauren MacLean	Wed - AM	11:20-11:30	10
Proactive Service Replacement	Barry Foster, Lae Hunt, Lauren MacLean	Wed - AM	11:30-11:45	15
Purchase Meters (Replacement)	Andrew Conlon, Lae Hunt, Jer Kue	Wed - AM	11:45-12:00	15
Lunch			12:00-1:00	60

Corrosion

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Corrosion	$1,305	$1,305	$1,434	$1,506	$2,941	Gene Au, May Zhen, Lae Hunt, Lauren MacLean

Program Overview

- Cathodic protection effectively extends the service life of buried steel facilities (as compared to unprotected buried steel facilities) and can prolong replacement by 20 years or more.
- Program maintains compliance with Federal and State Mandates
- **Program has 2 components**
  - **Underground:** controls consist of pipe coatings and cathodic protection
    - Cathodic protection accomplished by establishing proper coatings on steel pipe segments, and installation of rectifiers, anodes, insulators, and test stations for the steel pipes.
  - **Atmospheric Corrosion Protection:** controls consist of periodic inspections of exposed gas pipes and coatings (where present) and repairs of deficiencies.

Replace Pipe on Bridges
Access Protection Remediation

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Categories	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Replace Pipe on Bridges	$900	$200	$750	$3,800	$4,550	Gene Au, Barry Foster, Lae Hunt
Access Protection Remediation	$272	$272	$208	$282	$490	Gene Au, Barry Foster, Bao Hang

- Replace Pipe on Bridges:
  - FY23: Forecast reduced to $200K from $900K based on anticipated work
  - CY23: Work on Sylvan Drive bridge and Old River Road bridge. Development for other locations
  - CY24: Construction on Glenbridge Avenue bridge (replace 2 gas mains), Goat Island bridge, Admiral Street bridge, River Street bridge
- Access Protection Remediation
  - Purpose: Reduce risk of public injury by reducing and/or deterring public access to elevated gas facilities.
    - Typically fencing to prevent people from walking on pipe attached to bridge crossings.
  - CY23 and CY24 Budgets are likely going to decrease as work will primarily be reactionary.

Valve Installation/Replacement – Primary Valve Program & Aquidneck Island Low Pressure Valves

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Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Valve Installation/Replacement - Primary Valve Program & Aquidneck Island Low Pressure Valves	$988	$350	$606	$144	$750	Brandon Flynn, Lae Hunt, Lauren MacLean

Program Summary

- Purpose: Valves are used to sectionalize portions of the gas network to support both planned and unplanned field activities.
  - Replacement of inoperable valves (reactively) if necessary to ensure the ability to isolate portions of the distribution system.
  - New valves are also occasionally needed to provide capability to reduce the size of an isolated area.
- 21-Month Workplan
  - Newport Sectionalizing Valve Work - $0.50M – CY23
  - Reactionary Valve Work - $0.25M – Across CY23 & CY24

Low Pressure System Elimination (Proactive)

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Low Pressure System Elimination (Proactive)	$2,000	$700	$1,300	$2,071	$3,371	Brandon Flynn, Barry Foster, Corey Hogg, Lae Hunt, Jessika Soto

- Replace low pressure gas systems with high pressure systems to enhance gas system safety.
- Installing new high pressure distribution mains, services, and regulators and safely transferring customers from low pressure to the high-pressure system – Being done in response to recommendations by Federal and State Agencies following Columbia Gas incident in MA in 2018.
- 21-Month Planned Work
  - Complete final stages of LP System Elimination project in Middletown
    - Will install 3.6 miles of new main; Abandon 0.5 mile of LPP
    - A separate workorder (Public Works) will also be completed in this area ahead of paving
    - Will enable future abandonment of Walcott Ave new Briarwood Ave LP Regulator Station

Gas System Reliability/ Gas Planning

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Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Gas System Reliability	$3,260	$500	$2,520	$3,423	$5,943	Brandon Flynn, Lae Hunt, Jessika Soto, Agnieszka Przybysz

Program Overview

- Program identifies projects that support system reliability through standardization and simplification of system operations (i.e. system up-ratings and de-ratings and regulator elimination), integration of systems (i.e. tie-ins), and new supply sources (i.e. take stations)

- ## 21-Month Planned Work
  - Ongoing multi-year projects designed to eliminate single-feed systems (and low pressure segments, where applicable)
    - Providence, North Providence, Lincoln, Woonsocket
    - Install ~3.5 miles. Result in abandonment of ~2.1 miles LPP

Reactive Leaks (CI Joint Encapsulation/Service Replacement)
Service Replacements (Reactive) – Non-Leaks/Other

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Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	$10,100	$8,200	$6,200	$8,500	$14,700	Barry Foster, Lae Hunt, Lauren MacLean
Service Replacements (Reactive) - Non-Leaks/Other	$1,697	$1,697	$1,298	$1,757	$3,055	

Budgets for both categories align with FY23 Forecasts

Reactive Leaks:

- Leak sealing of cast iron bell joints, discovered during proactive leak surveys, public order calls, and other activities.
- Remediating leaking gas services through insertion, replacement, and/or abandonment on services.

Service Replacements (Reactive) – Non-Leaks/Other:

- Service abandonments, installation of curb valves, and service relocations.

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Main Replacement (Reactive) – Maintenance (incl Water Intrusion)

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Categories	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	$3,000	$1,000	$867	$1,174	$2,041	Barry Foster, Lae Hunt, Jessika Soto

- Emergency main replacements or modifications because of leaks or other unplanned events that typically dictate immediate replacement and/or gas facilities are subject to water intrusion or exposure and require remedy.
- 9-Month and 12-Month budgets closely align with FY 23 forecast
  - Oxbow Farms currently in a HOLD status. Project is in consideration for a Geothermal or Non-Pipes Alternatives type pilot (other projects would also be in consideration). Process to develop pilots and their locations will take at least a year.

Public Works

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Categories	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
CSC/Public Works - Non-Reimbursable	$20,596	$8,296	$18,040	$23,625	$41,665	Lae Hunt, Barry Foster, Jim Paulette, May Zhen, Chelsea Tervo, Jessika Soto
CSC/Public Works - Reimbursable	$1,437	$2,437	$1,099	$1,637	$2,736	
CSC/Public Works - Reimbursements	($1,433)	($4,300)	($824)	($982)	($1,806)	

Category	CY23 9-Month Leak-Prone Pipe Abandonment Miles	CY23 9-Month Main Replacement Installation Miles	CY24 12-Month Leak-Prone Pipe Abandonment Miles	CY24 12-Month Main Replacement Installation Miles
Public Works	9.0	14.0	14.0	14.0

- FY23 Non-Reimbursable Work and Forecast are lower than budget because
- For future years, Company assessing whether to expand types of projects that could be in-scope.
  - **Current qualifiers:** Leak Prone Pipe, Road undergoing full depth restoration
    - Has resulted in “missed opportunities” to replace old pipe prior to paving/moratoriums.
    - Milling/Paving process causes ground vibrations that can led to leaks.
  - **Future qualifiers under consideration:** Leak prone pipe, Road undergoing restoration (full depth or mill/overlay pave or general beautification project)

Public Works

- Opportunity/Advantages of expanding in-scope projects
  - Less disruption for our customers
  - Opportunity to save on final restoration costs

- Challenges to be addressed
  - Municipal Mill/Overlay jobs can fly-up quickly, depending on town planning

Main Replacement (Proactive) – Leak Prone Pipe

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Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Main Replacement (Proactive) - Leak Prone Pipe	$75,204	$87,783	$72,160	$85,006	$157,166	Corey Hogg, Barry Foster, Jessika Soto, Phil LaFond

	CY 2023 9-Month		CY 2024 12-Month		21-Month Plan	
Category	Abandonment Miles	Installation Miles	Abandonment Miles	Installation Miles	Abandonment Miles	Installation Miles
Proactive Main Replacement - LPP	39.5	46.9	53.4	51.9	92.9	98.8

- Consists of Cast Iron and Unprotected Steel Main with diameter of less than 16”
- In FY23, more work materialized in the MRP program than Public Works, so budget and resources were shifted to MRP
- In-service assumptions – changed to 60% of current year spend + prior year CWIP
  - Incorporated in-service change from Main gas-in/ first service to abandonment (starting 4/1/23).
  - In-Service (and abandonment) forecasts also impacted by changing year-end to 12/31 date
  - Decreased plant additions 21-month period from $151.15M to $138.91M
    - Public works decreased from $37.26M to $33.62M; In total, decreased 21-Month plant additions by $15.88M.
- Discussion: Company evaluating the implementation of a neighborhood approach.

Main Replacement (Proactive) – Leak Prone Pipe

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- Opportunity/Advantages of using a neighborhood approach
  - Neighborhood would have less disruption over time.
  - Opportunity to uprate LP systems to HP; may allow for installation of smaller diameter piping which typically installs faster (more efficient). Higher pressure also more efficient.
  - May result in fewer main connections that are required by in-house crews.
  - Mapping/Main Inventory – more definitive that all LPP has been eliminated in an area.
  - In future, could evaluate project/area for non-gas alternatives.

- Challenges to be addressed
  - Larger projects scopes will likely result in longer project duration. May increase time from gas-in to final abandonment.

Atwells Avenue

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Atwells Avenue	$1,464	$2,585	$1,500	$43	$1,543	Corey Hogg, Barry Foster

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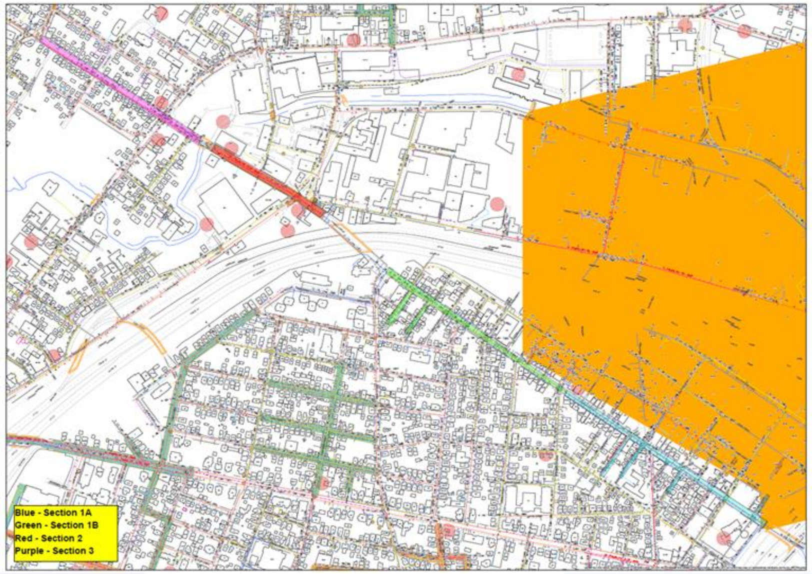
- Multi-year project in Providence through busy historical restaurant district. Some pipe was from 1800's. Highly congested underground utilities. Various parts of roadway crossings had pavers and granite that required restoration.
- Segments 1A & 1B – Main installation completed. Final restoration is ongoing. $400K for DePasquale Square (last major section to restore) was included in 21-month plan budget, but work has started in FY23;
  - 21-month budget will be reduced by the amount of work/spend completed in FY23.
- Segment 3 – Was included in FY23 budget, but likely delayed into 21-month plan. Company continuing to prioritize jobs with City of Providence Paving and Providence Water.
  - Segment 3 included in 21-month budget.



Main Replacement (Proactive) – Large Diameter LPCI Program

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Main Replacement (Proactive) - Large Diameter LPCI Program (CI Lining, CISBOT)	$2,250	$4,118	$2,859	$5,782	$8,641	Corey Hogg, Barry Foster, Lauren MacLean

- Company operates ~ 37 miles of Large Diameter leak prone gas mains (greater than or equal to 16”)
- These proactive programs consist of rehabilitating large diameter leak prone pipe through sealing and lining programs:
  - Lining and sealing are cost-effective alternatives for remediating large diameter leak prone pipe
  - Minimize impact to customers and communities, a shortened construction period and use of existing space in areas with significant underground utility congestion
- CI Lining: Petteys Ave in Providence. CY23 design & service transfers; CY24 0.4 mile of lining
- CISBOT: 2 Newport projects, 4 Providence projects
  - Will address ~1.7 miles of cast iron main

Main Replacement (Proactive) – Large Diameter LPCI Program

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CISBOT – Robotic Cast Iron Joint Sealing

Precise, Computer-Controlled Operation

CISBOT precisely drills into each joint and injects sealant using a computer-controlled system. The drill pressure and flow rate are continuously monitored to ensure a full joint seal every time.

Small Site Footprint Minimizes Disruption

With a minimal excavation and our CISBOT box truck, there are no road and sidewalk closures. With minimized disruption, businesses and residents can go about their day as usual.

Proactive Service Replacement

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Categories	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Proactive Service Replacement	$600	$230	$459	$621	$1,080	Barry Foster, Lae Hunt, Lauren MacLean

- **FY23:**
  - Working to complete the list of Cumberland Copper Services
    - 23 completed in FY23; 2 total remaining customers – challenging to work with
  - Another 11 have been replaced (1 HP Inside Set, 7 Steel Services on Plastic, 3 in PVD area)
  - Proactively scrubbing list of 701 potential leak prone services (not on LPP Main)

    Summary of Review:
    - 289: Service on Leak Prone Main
    - 236: Cancelled (does not need to be replaced)
    - 158: Remain on SRP list
    - 18: Need Field Checking
- **CY23:** Budgeted 75 Services; **CY24:** Budgeted 100 Services

Purchase Meters

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Purchase Meters (Replacement)	$5,248	$3,388	$5,910	$7,555	$13,465	Andrew Conlon, Lae Hunt, Jer Kue

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Program Overview

- Capital costs for procurement of meters
- Company has been dealing with industry supply chain issues. 21-month plan incorporates meter orders that were expected/budgeted in FY 2023 – but now expected to be delivered/paid for during 21-month period. Plan also increases baseline inventory.

- **CY 2023:** Require 14,820 meters (13,980 mandated, 840 misc.)
    - Will purchase 21,770 meters

- **CY 2024:** Require 19,759 meters (18,640 mandated, 1,119 misc.)
    - Will purchase 32,107 meters

Agenda – Wednesday - PM

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Categories	Leadership Team	Day/Slot	Time Range	Allotment
Lunch			12:00-1:00	60
Wampanoag Trail & Tiverton GS - Heaters Replacement and Ownership Transfer	Justin Zaccari, Lae Hunt, Phil DeMelo, Lauren MacLean	Wed - PM	1:00-1:10	10
Transmission Station Integrity	Justin Zaccari, Tom Mulkeen, Bao Hang, Agnieszka Przybysz	Wed - PM	1:10-1:40	30
Pipeline Integrity - IVP - Wampanoag Trail Pipeline Replacement	Tom Mulkeen, Lae Hunt, Bao Hang	Wed - PM	1:40-1:50	10
System Automation	Justin Zaccari, Tom Mulkeen, Lauren MacLean	Wed - PM	1:50-2:00	10
Heater Installation Program	Justin Zaccari, Tom Mulkeen, Luke MacDonald, Bao Hang	Wed - PM	2:00-2:15	15
Take Station Refurbishment	Justin Zaccari, Tom Mulkeen, Lae Hunt, Lauren MacLean	Wed - PM	2:15-2:25	10
Break			2:25-2:35	10
Pressure Regulating Facilities	Justin Zaccari, Tom Mulkeen, Lauren MacLean	Wed - PM	2:35-2:50	15
Distribution Station Over Pressure Protection	Justin Zaccari, Tom Mulkeen, Lauren MacLean	Wed - PM	2:50-3:05	15
Pipeline	Tom Mulkeen, Lae Hunt, Bao Hang, Agnieszka Przybysz, Andrew Hogan	Wed - PM	3:05-3:20	15
Other Upgrades/Investments		Wed - PM		
Regulator Station Investment		Wed - PM		

Wampanoag Trail & Tiverton GS
Heaters Replacement & Ownership Transfer

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Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Wampanoag Trail & Tiverton GS - Heaters Replacement and Ownership Transfer	$8,878	$9,381	$190	$0	$190	Justin Zaccari, Lae Hunt, Phil DeMelo, Lauren MacLean

- Tiverton:
  - FY23: Site work is currently ongoing and expected to be completed by end of FY. However, acceptance testing and resulting asset transfer will likely flow into CY23.
  - CY23 (9-Month) Budget: For project closeout costs
  - In-service date will likely flow into CY23 (9-month period)
- Wampanoag Trail: Heaters have been installed. Asset transfer and resulting in-service forecasted to occur in FY23

Wampanoag Trail & Tiverton GS
Heaters Replacement & Ownership Transfer

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New Tiverton M&R building with heating system and regulator station prefabricated inside. Station will be completed by end of year but tie-over to single feed system will be performed when weather permits.

New Wampanoag water bath heaters fully constructed, tied into new station inlet piping, and in-service. Site restoration to be completed by mid-November.

Transmission Station Integrity (1 of 2)

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Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Transmission Station Integrity	$4,510	$370	$4,249	$17,940	$22,189	Justin Zaccari, Tom Mulkeen, Bao Hang, Agnieszka Przybysz

- Purpose: to meet USDOT PHSMA code requirements, pursuant to 49 CFR §§192.624, which require operators of steel gas transmission pipeline segments to reconfirm MAOP of segments with documentation, including material property records by 2035.
- Currently in multi-year program: 12 of 24 Transmission Stations are in scope for re-testing and/or replacing equipment
- Scott Road Take Station Replacement: Complete full station and heater replacement
    - Budget CY23: $3.50M; CY24: $7.46M. ~$11.0M expected to go in-service during CY24

Transmission Station Integrity (continued 2 of 2)

- Wampanoag Trail Gate Station Replacement & Ownership Transfer
  - Budget CY23: $0.71M; CY24: $10.36M. ~$10.62M expected to go in-service during CY25
    - Separate from heaters transaction
  - Station replacement necessary to address integrity verification concerns regarding lack of Traceable, Verifiable, and Correct (TVC) asset records and the stations age (approx. 36 to 68 years old) and condition are also of concern.
  - Critically important station: it’s the only 200 PSIG gate station that feeds Providence and East Providence distribution systems. Responsible for initial supply point for approximately 65,000 customers, based on its peak flow.
  - Replacement will reconfirm MAOP and create new material verification records of existing piping, as required by PHMSA.
  - Will ensure the 200 PSIG system is fed by a gate station that has 3 layers of overpressure protection, owned and operated by RIE. Isolation valves will indicate clear line of demarcation.
  - Ownership transfer allow RIE to ensure maintenance of the equipment and ability to provide pressure control to its major distribution systems in the area.
  - After Wampanoag and Tiverton are completed, the Westerly gate station will be only gate station on RIE system where pipeline supplier provides pressure control.

Pipeline Integrity – IVP – Wampanoag Trail Pipeline Replacement

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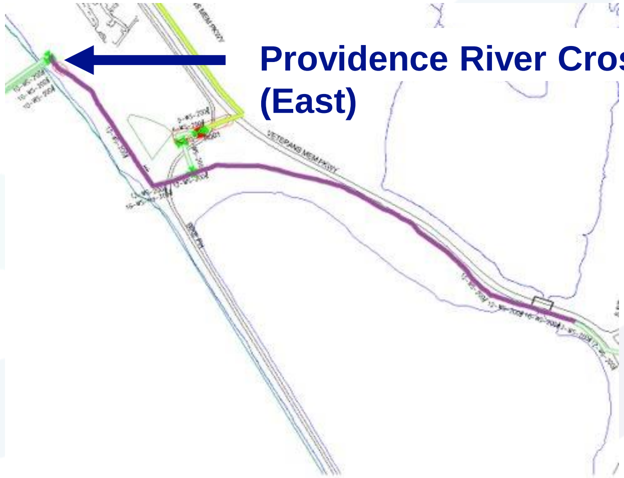
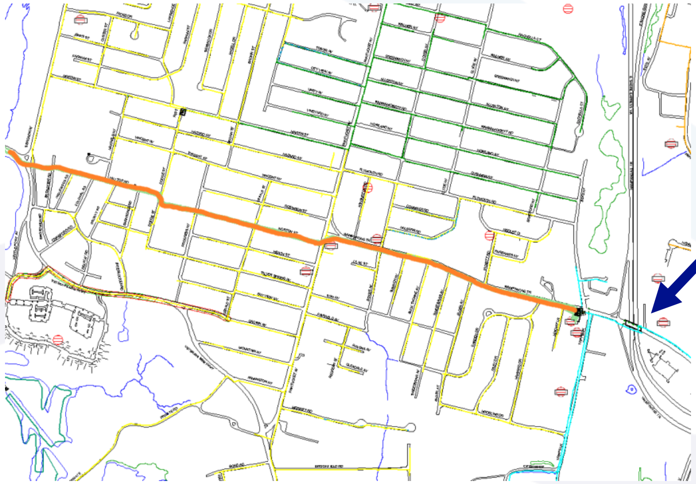
Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Pipeline Integrity - IVP - Wampanoag Trail Pipeline Replacement	$500	$185	$375	$3,750	$4,125	Tom Mulkeen, Lae Hunt, Bao Hang

- ~5-year project to replace ~2 miles of transmission main in East Providence, which runs from the Providence River Crossing to Wampanoag Trail Take Station.
  - This section of 12”-16” coated steel piping is some of the oldest main operating at 200 PSIG (installed before 1971) on the RI System and is critical piece of infrastructure for RI gas supply.
  - Budget: CY23 - $0.38M engineering and design; CY24 - $3.75M materials and begin construction



Providence River Crossing (East)



Wampanoag Trail Take Station

System Automation

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
System Automation	$800	$800	$692	$810	$1,503	Justin Zaccari, Tom Mulkeen, Lauren MacLean

Program Summary

- Purpose: Meet US DOT code requirements under 49 C.F.R. Part 192 Docket ID 2007-27954, issued 12/3/2009
  - Contains the following pipeline safety requirements:
    a) Control room management/ human factors;
    b) Modernization of Company's system data and telemetry recording;
    c) Increasing the level of system automation and control
- Company has 189 gas pressure regulators on RI System
  - All stations in RI Northern Region now have telemetry
  - Some stations still require installation of new telemetry equipment
- 21-Month Plan: Provide alternating current power, telemetry and/or remote control to 10-20 locations in CY23 and another 10-20 locations in CY24

Heater Installation Program

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Heater Installation Program	$1,242	$1,154	$5,006	$1,477	$6,483	Justin Zaccari, Tom Mulkeen, Luke MacDonald, Bao Hang

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Program Summary

- Purpose: Installation and replacement of gas system heaters, which are operated to ensure proper conditioning and control of gas temperatures at key Company facilities.
- 21-Month Workplan
  - Dey Street, PVD - $2.60M – 1 water bath heater; CY23 Install, CY24 Closeout
  - Diamond Hill, Cumberland - $1.20M – Hydronic boiler system; CY23 Materials, CY24 Install
  - Smithfield Gate Station - $1.99M – Hydronic boiler system (starting in FY23), heat exchanger piping and piping to take station; Complete Install in CY23
  - Program Blanket - $0.70M – fuel train upgrades, heat exchanger replacement, engineering costs, burner management/ safety system upgrades, etc.

Take Station Refurbishment

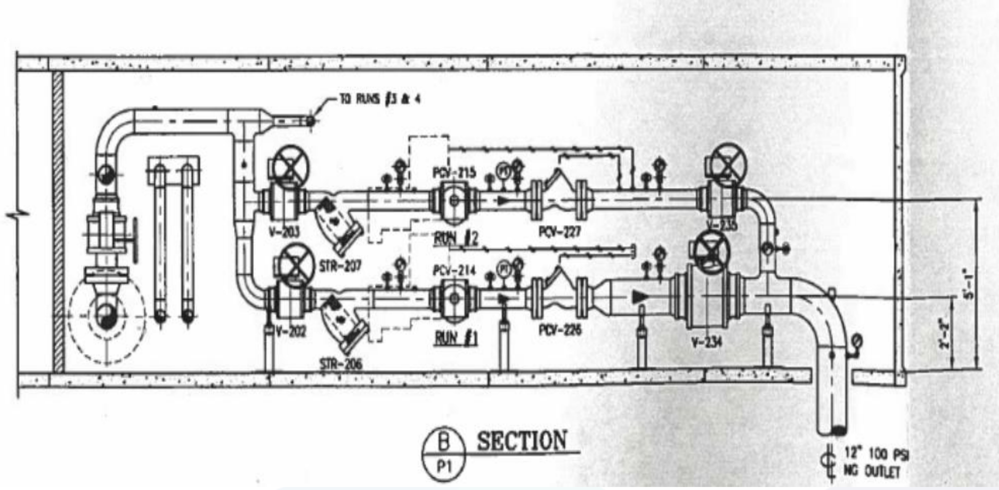
Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Take Station Refurbishment	$1,150	$1,154	$1,064	$2,751	$3,815	Justin Zaccari, Tom Mulkeen, Lae Hunt, Lauren MacLean

Program Summary

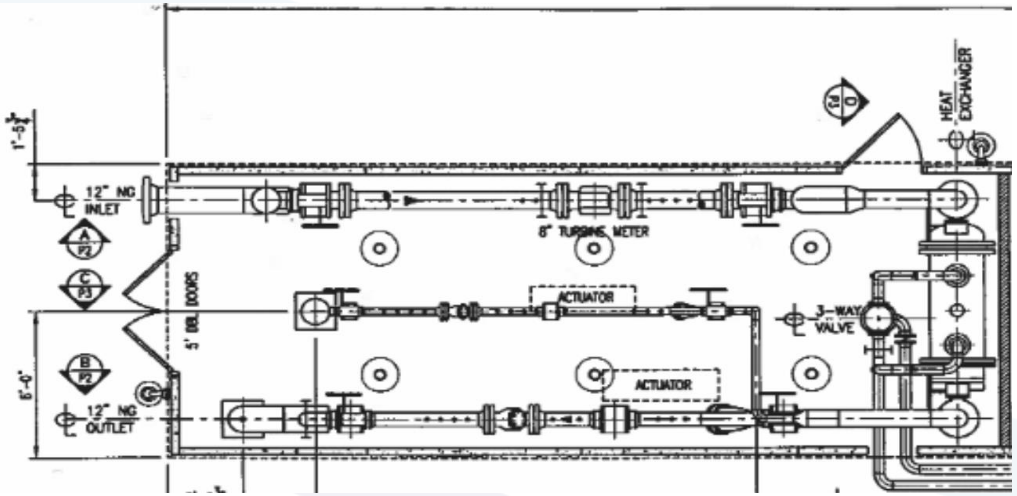
- Purpose: Addresses required modifications to the Company's custody transfer stations.
- 21-Month Workplan includes
  - Smithfield Gate Station: $3.36M
    - CY23: Install new distribution vault outside, Engineering for replacement of inside gate station regulator runs
    - CY24: Materials procurement, Replacement of inside gate station regulator runs
  - Blanket: $0.45M – Odorization and generator upgrades, etc.

Take Station Refurbishment

- Smithfield Gate Station does not require full replacement of the Take Station since its less than 25 years old and almost 80% of its records have been verified. A partial rebuild is required since its original design in 1999 does not allow the installation of third layers of overpressure protection due to its stacked run configuration. The refurbishment project will also eliminate the 1000 PSIG to 35 PSIG pressure cut which mitigates the risk of a large over-pressurization of that system.



Side-View 99 PSIG Outlet (Spring to Close Actuators do not fit on stacked runs. Will become side-by-side redundant 99 PSIG runs.)



Overhead View 35 and 99 PSIG Outlet (Center 35 PSIG runs to be moved to new regulator vault with an inlet from the 99 PSIG system)

Pressure Regulating Facilities

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Pressure Regulating Facilities	$7,585	$5,585	$6,323	$8,441	$14,764	Justin Zaccari, Tom Mulkeen, Lauren MacLean

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Program Summary

- Purpose: Provides for condition-based assessments of all regulator stations, which include station accessibility, pipe condition (i.e. corrosion), water intrusion, redundancy, station isolation, and common mode failure.
- 21-Month Workplan includes
  - CY23: $6.32M
    - Construction at 5-7 stations, Engineering for 5 future stations, Install second bypass valve at 1-2 stations
  - CY24: $8.44M
    - Construction at 6-8 stations, Engineering for 8 future stations, Install second bypass valve at 2-3 stations

Pressure Regulating Facilities

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The chart below contains the locations of the proposed work under pressure regulating facilities as well as station details and information that influenced each work proposal. The scope of all station replacements is to install the following: a dual-run prefabricated regulator station with three layers of overpressure protection on each run; protective bollards; vents; and a traffic box containing system automation equipment. It is preferred to install the new station in the same location as the old station unless a new location is safer or more strategic. The scope of all station abandonments is to completely isolate, depressurize, cut, cap, and retire in place.

Station Name	Town	Comment:	Project Type	Risk Ra	Schedule Ri	Priorit	Expected 9 Month Completi	Expected 21 Month Completion
Park Av @ Maple Av	CRANSTON	Carry Over	Replacement	12		1		
Station St @ Pond St	CRANSTON	Carry Over	Replacement	4		2		
Smith St @ Sunset Av	NORTH PROVIDENCE		Replacement	1		3		
Weeden St @ Smithfield Av	PAWTUCKET		Replacement	2		4		
337 Lonsdale Av	PAWTUCKET		Replacement	3		5		
Mendon Rd @ Nate Whipple Hwy #1	CUMBERLAND	Semi-Complex	Replacement	10		6		
Wellington St @ Thames St LP	NEWPORT		Replacement	7		7		
New River Rd @ Cottage St	LINCOLN		Replacement	6		8		
Mendon Rd @ Nate Whipple Hwy #2	CUMBERLAND	Semi-Complex	Replacement	10		9		
110 Atwood Av @ D St	CRANSTON		Replacement	5		10		
235 PROMENADE ST @ KINGSLEY AV	PROVIDENCE		Abandonment	11		11		
347 Putnam Pike TS (Rt 44) 35 PSIG	SMITHFIELD	Semi-Complex	Replacement	9		12		
Walcott Av @ St Georges	MIDDLETOWN	Semi-Complex	Abandonment	13		13		
1584 Plainfield St @ Plainfield Pk	CRANSTON	Alternate	Replacement	8		14		
Wellington St @ Thames St 40 PSIG	NEWPORT	Alternate	Replacement	14		15		

A second bypass valve will also be installed at 5 pressure regulating facilities.

Distribution Station Over Pressure Protection

Categories ($000)	FY23 Budget	FY23 Q2 Forecast	CY 23 9-Month Budget	CY 24 12-Month Budget	21-Month Plan Total	Leadership Team
Distribution Station Over Pressure Protection	$3,000	$2,500	$2,410	$1,877	$4,288	Justin Zaccari, Tom Mulkeen, Lauren MacLean

Program Summary

- Purpose: Addresses risks for over pressurization incidents at pressure regulating facilities
  - Relocate and provide additional protections for regulator sensing and control lines to protect from third-party damage, and installation of additional control equipment to ensure safe and reliable regulator operation in the event of control line damage.
- Workplan
  - CY23
    - Purchase materials for 1-2 new relief valves
    - Install 3-5 outlet control line headers and
      - Cranston, Middletown, Woonsocket, East Providence, Pawtucket
  - CY24
    - Install 1-2 new relief valves on system
    - Install 1-3 outlet headers

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Appendix

Gas System Reliability/ Gas Planning – FY23 Slide

- FY2023 Project List – included for reference

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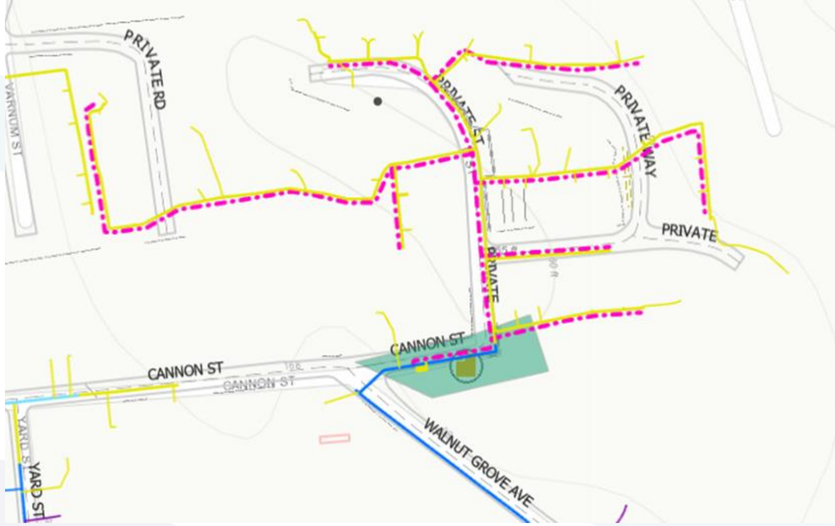
Project/ Location	Town	Description	LPP CI - Length	LPP BS - Length	Install ft	Cost Estimate
LTRI Reliability - Newport (10-to-35)	Newport	Part of a multi-phase project to eliminate the single-feed 10-psig subsystem and integrate with the larger 35-psig system via main replacement, starting at Beacon Hill Rd, Newport. Phases 1 & 2.	150	275	2,800	$589
	Newport		1,800	505	3,930	$907
LTRI Reliability - Small Single-Feed Station Subsystems 1	Cranston	Eliminate single-feed 35-psig subsystem and regulator station at 200-Cannon St, Cranston. Integrate with 99-psig system via main replacement to improve reliability.	-	-	2,610	$741
LTRI Reliability - Small Single-Feed Station Subsystems 2	Warwick	Eliminate three single-feed 30/35-psig regulators off Bald Hill Rd, Warwick. Integrate with larger 99-psig system via main replacement to improve reliability.	-	-	3,580	$575
East Providence Downrate - Narragansett Park Dr (35-to-18)	East Providence	Eliminate single-feed 35-psig subsystem located in East Providence near the Pawtucket town line. Integrate into the larger 18-psig system via pressure downrate to improve reliability.	635	575	260	$448

Map of Cranston Project



Summary of slide edits made on November 3, 2022

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The following changes were made to this slide deck presentation on November 3, 2022 (after the Walkthroughs).

Slide 16 -

Replace Pipe on Bridges: FY23 Forecast decreased from $900K to $200K based on anticipated work.

Access Protection Remediation: Inserted note for Access Protection Remediation, which reads as follows:

- CY23 and CY24 Budgets are likely going to decrease as work will primarily be reactionary.

Slide 20 – Service Replacements (Reactive) – Non-Leaks/Other: Removed 2nd bullet (was inadvertently copied in from a different topic/slide)

Slide 21 – Deleted – was a duplicate of slide 20 – Slide 21 was intentionally left blank to avoid changing the existing page numbers.

Slide 22 – Updated the leadership team list – Swapped Jessika Soto in, Lauren MacLean out.

Slide 23 – Corrected spelling on May Zhen's name within the leadership list.

Slide 27 – Atwells Ave: Updated Segment 1A & 1B commentary to list $400K as the amount allocated for DePasquale Square.

Slide 39 – Heater Installation Program: Updated note for Smithfield Gate Station to note that the Hydronic boiler system is starting in FY23). Now reads as follows:

- Smithfield Gate Station - $1.99M – Hydronic boiler system (starting in FY23), heat exchanger piping and piping to take station; Complete Install in CY23