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Southwest Gas Corporation

SOUTHWEST GAS CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

| | |
|---|---|
| In the Matter of the Application of Southwest Gas Corporation for Approval of its Nevada Resource Plan Pursuant to NRS 704.991 et seq. | Docket No.: 25-09___ |

**VOLUME 2 of 2**

Testimony

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Southwest Gas Corporation

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Exhibit 3

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY
OF
KEVIN M. LANG

ON BEHALF OF
SOUTHWEST GAS CORPORATION

September 17, 2025

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of
Prepared Direct Testimony
of

Kevin M. Lang

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Kevin M. Lang

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Kevin M. Lang. My business address is 8360 S Durango Dr., Las Vegas, NV 89113.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Engineering Staff department. My title is Vice President/Engineering Staff

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (PUCN or Commission), the Arizona Corporation Commission, and the California Public Utilities Commission.

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 The purpose of my prepared direct testimony is to provide a pipeline safety perspective and background on the Company's proposed replacement and safety related programs in this filing.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My prepared direct testimony consists of the following:

- An overview of the Company's Distribution Integrity Management Program

(DIMP).

- An overview of the Company's Transmission Integrity Management Program (TRIMP).
- The Company's proposed Vintage Steel Pipe (VSP) replacement projects in Southern Nevada and Northern Nevada.
- The Company's proposed 1984/1985 (84/85) Pipe Replacement Program.
- A pipeline safety perspective on the Company's proposed Natural Gas Alarm Pilot Program.
- An asset management perspective on the Company's proposed Encoder, Recorder, Transmitter (ERT) Replacement Program.
- A pipeline safety perspective on the Company's Proposed Meter Protection Program

## II. DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

**Q. 7 Please provide a brief overview of the Company's Distribution Integrity Management Program (DIMP).**

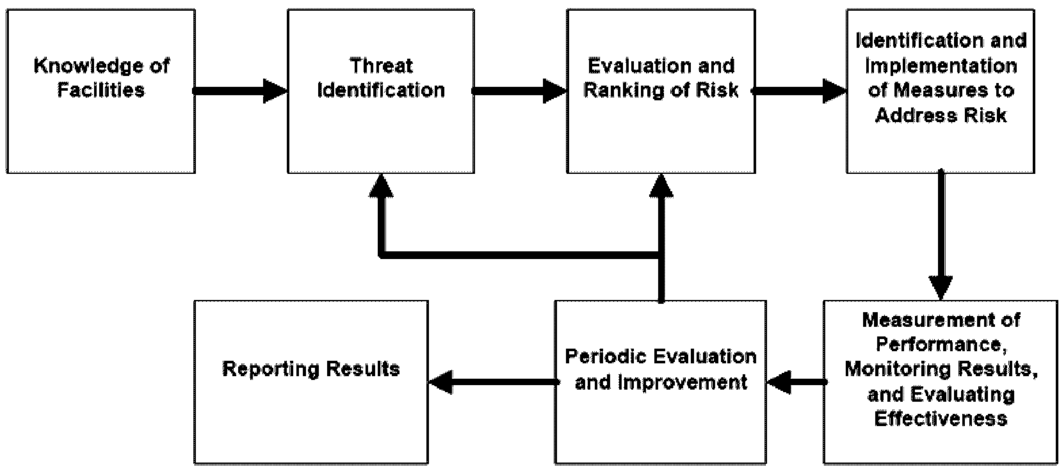
A. 7 DIMP is a risk-based process designed to gather and evaluate information about the Company's distribution pipelines and to prioritize and implement actions based on that information to maintain the safety and integrity of the Company's distribution system. The Company's DIMP is designed around the concept of continuous improvement, and is based upon seven key elements:

1. Knowledge of the distribution system;
2. Identification of threats;
3. Evaluation and ranking of risks;
4. Identifying and implementing measures to address risk;
5. Measuring performance, monitoring results, and evaluating effectiveness;

6. Periodic evaluation and improvement of the DIMP plan; and,

7. Reporting results.

The first element of DIMP is the operator's knowledge of its distribution system. Federal and state DIMP regulations require an operator of a natural gas distribution system to demonstrate an understanding of its gas distribution system developed from reasonably available information. This information is obtained through an operator's operations and maintenance records as well as original installation records, if available.




**Q. 8 What type of method does the Company utilize to prioritize its pipe replacement projects?**

A. 8 The Company utilizes an asset management process to prioritize pipe replacement and other Company natural gas assets. This process utilizes a common risk assessment system for all natural gas facilities and groups them into asset families by asset type rather than by individual categories targeting specific types of replacement. The asset management allows the Company to identify the highest risk pipe segments and other Company assets required for replacement.

**Q. 9 How does the Company utilize its knowledge of its Nevada distribution system to make informed asset management decisions for DIMP?**

A. 9 The Company's DIMP collects and evaluates information about its distribution pipelines and the environment in which they operate. This information includes pipe and component materials and operating and maintenance history including information on leaks and leak causes. One of the key metrics incorporated into the Company's DIMP Plan is an annual analysis and review of the leak rates of each of the Company's pipe types.

Pipe materials have evolved over time since the initial gas distribution systems were installed in Nevada by Southwest Gas and its predecessors. Pipe material types in the Company's Nevada distribution system include steel and a variety of plastic pipe types starting in the late 1950s to the modern high-density polyethylene (HDPE) plastic pipes utilized by the Company today. The Company's annual leak rate analysis reviews leaks identified during the previous calendar year, the cause of each leak, and how this information compares to the overall composition of the Company's distribution system.

Southwest Gas utilizes its leak rate analysis, coupled with information from the Company's laboratory evaluation of failed or leaking components in its distribution system, its field order management system, and the Company's excavation damage cause database to perform an annual, in-depth identification of threats to its distribution system and determine the performance of the various pipe types installed within the system.

**Q. 10 What is the Company proposing as it relates to its DIMP?**

A. 10 The prepared direct testimony of Company Witnesses Thomas W. Cardin and Christopher R. Anderson describe the various pipe replacement actions driven by the Company's DIMP. The prepared direct testimony of Company Witness Christopher M. Brown discusses the estimated customer rate impacts associated with proposed projects. Furthermore, additional DIMP background details of the Company's proposed pipe replacement program associated with the threat of leakage on 84/85 HDPE is further described below in Q&A 14.

## III. TRANSMISSION INTEGRITY MANAGEMENT PROGRAM

**Q. 11 Please provide a brief overview of the Company's Transmission Integrity Management Program (TRIMP).**

A. 11 The Company's TRIMP addresses transmission pipelines in locations where people gather, called High Consequence Areas (HCAs). Pipelines in HCAs are inspected beyond normal levels of operations and maintenance. These inspections, called assessments, are repeated at a regular interval, for an increased level of awareness and maintenance. This comprehensive program is designed to ensure the integrity of gas transmission pipelines located where a leak or rupture could do the most harm.

Additional federal pipeline safety regulations were promulgated following several high-profile gas transmission incidents to ensure that transmission pipelines had traceable, verifiable, and complete records to establish and verify each pipeline segment's Maximum Allowable Operating Pressure (MAOP). This process, known as MAOP Reconfirmation, is undertaken by operators of certain natural gas transmission pipelines when adequate records are missing or incomplete.

**Q. 12 When does the MAOP Reconfirmation process apply to gas transmission pipelines?**

A. 12 MAOP Reconfirmation requirements are specified within 49 Code of Federal Regulations (CFR) Part 192.624 and are generally described as required for gas transmission pipelines installed prior to 1970 that are currently operating at or above 30% of the specified minimum yield strength (SMYS) for applicable pipeline segments operating in HCAs, Class 3 or 4 locations, or Moderate Consequence

Areas (MCAs). The SMYS of the pipeline is representative of the internal stress level, or hoop stress, of the pipeline. Allowable methods for MAOP Reconfirmation are described in 49 CFR Part 192.624(c) and include pipe replacement, pressure testing, and other more complex engineering methods. 49 CFR Part 192.624(b) requires operators of applicable gas transmission pipelines to complete at least 50% of the identified gas transmission pipeline MAOP Reconfirmation by July 3, 2028, with the remaining balance completed by July 2, 2035. Provisions are also included in 192.624(b) for newly identified segments as soon as practicable before July 2, 2035, but not to exceed 4 years after the pipeline segment first meets a condition of 192.624(a), whichever is later.

**Q. 13 What are the Company plans related to its MAOP Reconfirmation plan?**

A. 13 The prepared direct testimony of Company witness Thomas W. Cardin describes the Company's plans related to the completion of MAOP Reconfirmation for the STS "L" Line Integrity Management Replacement Project. The prepared direct testimony of Company Witness Christopher M. Brown discusses the Company's estimated customer rate impacts associated with MAOP Reconfirmation work.

## IV. VSP REPLACEMENT PROJECTS

**Q. 14 Please provide a brief overview of the Company's VSP Replacement Projects in Southern Nevada.**

A. 14 The Company has planned two VSP replacement projects that involve the replacement of VSP for the STS – the STS "L" Line Integrity Management Replacement Project and the STS Replacement Project. The STS "L" Line Integrity Management Project involves the replacement of approximately 3 miles of 16-inch vintage steel pipe (VSP) with a 24-inch steel pipeline. The STS "L" Line Integrity Management Project is planned for the action plan period.

The STS Replacement Project involves the installation of approximately 70 miles of 24-inch steel pipeline and abandonment of approximately 97 miles of pre-code 1956 and 1963 VSP. The STS Replacement Project is planned for a period of time beyond the action plan period and the discussion of that project is to provide additional context with respect to the STS. Company witness Thomas W. Cardin discusses the planned projects in more detail from an operations perspective in his prepared direct testimony.

**Q. 15 Please provide a brief overview of the Company's VSP Replacement Projects in Northern Nevada.**

A. **15** The Company has planned for the replacement of three vintage steel pipe (VSP) laterals in Northern Nevada: the Genoa Lateral Replacement Project, the Capehart Lateral Replacement Project and the Wadsworth Replacement Project (collectively VSP Replacement Projects). Company witness Christopher R. Anderson discusses the planned projects in more detail from an operations perspective in his prepared direct testimony.

**Q. 16 What safety and reliability concerns have been expressed about VSP?**

A. 16 The Pipeline and Hazardous Materials Safety Administration (PHMSA) and the National Transportation Safety Board (NTSB) have expressed three concerns about pre-1970s pipe: (1) seam welds, (2) pipe that has not been pressure tested and has a Maximum Allowable Operating Pressure (MAOP) established by a historic operating pressure in accordance with the Department of Transportation Pipeline Safety Regulations Part 192, commonly referred to as the "Grandfather Clause", and (3) MAOP confirmation and records verification for pipeline system components in class 3 and 4 locations and class 1 and class 2 high consequence areas utilizing traceable, verifiable, and complete acceptance criteria. Similarly, the continued focus on modernizing natural gas systems was reiterated in a PHMSA Safety of Gas Transmission & Gathering Lines rulemaking.[1]

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[1] Docket No. PHMSA-2011-0023; Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments.

Regulatory Operations Staff (Staff) of the Commission has also noted several concerns with pre-code VSP throughout various Company proceedings before the Commission.[2] The Commission has also expressed concern with the Grandfather Clause and reliance on historical operating pressures versus documented testing, decades after enactment of the federal pipeline safety code, for example.[3]

**Q. 17 Do the Company's proposed VSP Replacements address a safety and reliability issue?**

A. 17 Yes. PHMSA, the NTSB, Staff and the Commission have all identified concerns regarding natural gas transmission pipelines which were installed prior to the adoption of 49 CFR Part 192. Those concerns include seam welds, pipe where the MAOP is established under the "Grandfather Clause" or historical operating pressure (HOP), MAOP confirmation and records verification, quality of the steel metallurgy, the quality of the coating, quality of cathodic protection, and whether welds were subjected to non-destructive evaluation. Both the STS "L" Line Integrity Management Project, the STS Replacement Project and the Northern Nevada VSP Replacement Projects address these safety and reliability concerns.

**Q.** 18 **How are safety and reliability concerns addressed by the VSP Replacement Projects?**

A. 18 The VSP Replacements Projects address the safety and reliability concerns through installation of modern pipe, use of modern installation methods (e.g. coating, pressure testing, depth, etc.), uniformity of pipeline wall thickness, documented pressure test and MAOP records, and capability for the passage of in-line inspection tools for ongoing integrity management assessments. These improvements to the system's safety and reliability mitigate risk and serve the public interest. In addition, the replacement of vintage pipe with new, modern pipe

[2] Docket No. 14-05042, Order at pages 22 – 23.
[3] *Id* at pages 30-31.

results in the new pipeline operating at a lower SMYS.

## V. 84/85 PIPE REPLACEMENT PROGRAM

**Q. 19 Please provide a brief overview of the Company's 84/85 pipe.**

A. 19 As described in Q&A 7, a key element of the Company's DIMP is to identify threats, evaluate and rank risks, and identify and implement measures to address risk. As part of the Company's DIMP process, an emerging threat was identified in leaks on 2-inch HDPE pipe at butt fusions installed in 1984 and 1985 in the Company's Southern Nevada service territory in the Las Vegas and Laughlin areas.

The Company evaluated known leaks on this vintage of pipe installation and created a DIMP threat checklist in 2012 to identity an applicable risk assessment and risk mitigation measures in the form of accelerated actions including quarterly leak surveys of known installations, and an evaluation for replacement when leaks are discovered. The Southern Nevada 1984-1985 2-inch HDPE butt fusion failure DIMP threat checklist is provided as Exhibit No.__(KML-1).

**Q. 20 What is the Company proposing as it relates to 84/85 pipe?**

A. 20 The Company continues to experience leaks associated with the threat of 84/85 HDPE butt fusions with approximately 113 related leaks discovered to date. As discussed in more detail in Mr. Cardin's prepared direct testimony, the Company proposes to replace the remaining known mileage of 84/85 2-inch HDPE pipe in the Company's Southern Nevada distribution system to eliminate the risk associated with the known threat. Company Witness Christopher M. Brown describes the Company's proposed cost recovery and estimated customer rate impact associated with the 84/85 Pipe Replacement Program.

**Q. 21 Why is the Company proposing to replace 84/85 pipe now?**

A. 21 To date, the Company has replaced 84/85 pipe on a case-by-case basis when a leak is discovered and has not developed a targeted, proactive replacement program to eliminate the known 84/85 pipe from its system. The Company has focused on completing the replacement of vintage plastic pipe such as Aldyl-A and PVC under its Early Vintage Plastic Pipe (EVPP) Replacement Program in Southern Nevada[4], with less than 10 known miles remaining to replace. Given the outstanding threat of 84/85 pipe and the limited number of known miles of EVPP left to replace, the Company believes it is reasonable and prudent to begin the targeted replacement of 84/85 pipe in its Southern Nevada distribution system as described by Mr. Cardin.

**Q. 22 Why is the Company's DIMP risk assessment process not identifying all 84/85 pipe to be replaced?**

A. 22 The Company's DIMP risk assessment process ranks the risk of each pipeline segment and is based upon historical leakage data. Currently, 84/85 pipe segments are identified for replacement <u>after</u> they experience leakage. Similar to the Company's experience with EVPP, the overall population of the affected pipe has reached a level where proactive replacement of the remaining population is a reasonable and prudent action to eliminate this threat to the Company's Nevada distribution system to enhance public safety and system reliability.

**Q. 23 Are there other benefits to establishing the 84/85 Pipe Replacement Program?**

A. 23 Yes. As discussed above, the Company continues to experience leaks associated with the threat of 84/85 HDPE butt fusions with approximately 113 related leaks discovered to date. Proactive replacement of this pipe can reduce and eliminate future leaks thereby reducing or avoiding greenhouse gas emissions.

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[4] On March 8, 2022, the Commission issued an Order in Docket No. 21-08009 approving a stipulation between the PUCN Regulatory Operations Staff and Southwest Gas. The order includes a Commission directive that requires the Company to remove all known EVPP in Southern Nevada by December 31, 2024, unless prevented by circumstances beyond the Company's direct control which include, but are not limited to, labor shortages, permitting delays, and force majeure events. On June 26, 2025, Southwest Gas filed an update letter in the aforementioned docket.

## VI. NATURAL GAS ALARM PILOT PROGRAM

**Q. 24 What is a natural gas alarm?**

A. 24 A natural gas alarm, also referred to as a methane detector, is a device that monitors the air in a home or business for the presence of methane, the main constituent of natural gas. These devices operate similar to a smoke or carbon monoxide detector to provide an early warning to the occupants of the presence of methane by providing an audible alarm to occupants before methane concentrations reach a flammable or explosive level. Multiple manufacturers produce commercially available devices that can be installed in homes and businesses to detect natural gas.

**Q. 25 Is there a current local, state, or federal code that requires the installation of natural gas alarms in residential homes or businesses?**

A. 25 No. Unlike smoke or carbon monoxide detectors, there is no current building code or standard that requires the installation of a natural gas alarms in residential homes or businesses. However, following several high-profile natural gas related incidents in which fatalities occurred, the NTSB made formal recommendations in 2025 to natural gas operators, natural gas associations, and the States[5] to require the installation of natural gas alarms that meet the specifications of National Fire Protection Association (NFPA) 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak[6].

Additionally, the NTSB made recommendations to International Code Council (ICC)[7], which administers the International Fuel Code (IFC), and International Fuel Gas Code (IFGC) as well as the NPFA[8], to require installation of natural gas alarms in the applicable building and fire codes that are adopted by

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[5] A letter was transmitted to Governor Lombardo's office on April 8, 2025, documenting this recommendation to the State of Nevada. See Exhibit No.__(KML-2).
[6] NTSB Recommendation P-25-5. See Exhibit No.__(KML-3).
[7] NTSB Recommendation P-25-13 and P-25-14. See Exhibit No.__(KML-3).
[8] NTSB Recommendation P-25-15. See Exhibit No.__(KML-3).

state and local agencies which govern new construction and building standards.

Following previous industry incidents and a similar recommendation from the NTSB after the 2018 Silver Springs, Maryland incident, the Company began discussions with Staff about natural gas alarms and Southwest Gas commenced small scale testing and evaluation of such alarms at the Company's training facility. As noted in the PUCN's August 11, 2025, response letter[9] to NTSB, additional discussions were held regarding the feasibility of a potential natural gas alarm pilot program for certain customer classes in Nevada following the April 8, 2025, letter to Governor Lombardo on NTSB P-25-5 recommendation to the State of Nevada.

**Q. 26 What are the enhanced public safety benefits with the installation of natural gas alarms in areas such as homes and places where people congregate?**

A. 26 The first line of defense when a natural gas leak occurs is a person's nose. Southwest Gas is required to ensure the natural gas it delivers to customers contains a detectible level of odorant. The odorant, or Mercaptan, is an additive to natural gas that produces a distinct, sulfur-like odor, similar to rotten eggs. While odorant can act as an early warning of a natural gas leak, odorant levels can become depleted as a natural gas leak travels through soil or if a person's sense of smell is diminished. A natural gas alarm is sensitive enough to detect methane levels even if the odorant in the gas is not readily detectible. The presence of a natural gas alarm would alert occupants of the potential hazard so that they can evacuate to a safe location and contact 911 and Southwest Gas to investigate, significantly reducing the potential for harm to the public in the event of a leak or migration of gas into an occupied structure.

**Q. 27 What is the Company proposing with regards to natural gas alarms?**

A. 27 To enhance public safety and public awareness, the Company is proposing a 3-

[9] PUCN Response Letter to NTSB. See Exhibit No._(KML-6)

year Natural Gas Alarm Pilot Program (Pilot Program) in both its Northern and Southern Nevada service territories that will involve the purchase, distribution and installation of up to 10,000 natural gas alarms in high occupancy facilities, including educational facilities and community centers, churches, as well as residences in "historically underserved communities", as defined by Nevada Revised Statutes (NRS) 704.78343. A Program Overview of the proposed 3-Year Pilot Program is provided as attachment Exhibit No._(KML-7). During the 3-year Pilot Program, the Company will evaluate the effectiveness of the Program by documenting where and when the natural gas alarms were installed, tracking the number of customer calls as a result of the natural gas alarms, the accuracy of the leak detected, and a survey to customers who received a natural gas alarm after the 3-year period to gather information if the natural gas alarm is still installed. This information will help the Company determine the effectiveness of the Pilot Program. The Prepared Direct Testimonies of Company Witnesses Thomas W. Cardin and Christopher R. Anderson describe the proposed scope and estimated cost of the Company's proposed Pilot Program. The prepared direct testimony of Company Witness Christopher M. Brown discusses the Company's proposed cost recovery and estimated customer rate impacts for the proposed Pilot Program.

**Q. 28 How many natural gas alarms is the Company purchasing, distributing and installing?**

A. 28 The Company is requesting to initially purchase up to 10,000 natural gas alarms for distribution and installation within the defined target customer types outlined within the Program Overview.

**Q. 29 Depending on the success of the Pilot Program, does the Company propose making any adjustments?**

A. 29 Yes. If within the 3-year Pilot Program the Company deploys at least 9,000 natural gas alarms within the state, the Company is requesting authorization through this proceeding to purchase, distribute and install an additional 10,000 natural gas alarms consistent with the specifications outlined in the Program Overview.

**Q. 30 How did the Company determine that 10,000 natural gas alarms would be the appropriate amount to implement for the Pilot Program?**

A. 30 Factoring the number of customers Southwest Gas has in both Northern and Southern Nevada and the sample size for each target audience customer classes, it was determined that 10,000 natural gas alarms would be an appropriate number for the Pilot Program.

## <u>VII. ERT REPLACEMENT PROGRAM</u>

**Q. 31 What is an ERT?**

A. 31 An ERT is an electronic device attached to a gas meter that records consumption data and transmits that data wirelessly to a data collection device, allowing the Company to collect customer meter data for monthly billing purposes. The Company's current ERT system utilizes a low-level radio frequency to send data to Company vehicles as they drive without physically visiting each customer premise. The Company utilizes an Automated Meter Reading (AMR) process that requires a monthly driveby to collect the meter read utilizing the Itron mobile radio network.

**Q. 32 What types of ERTs does the Company have deployed today?**

A. 32 With the exception of large commercial and industrial meters, the majority of the Company's meters utilize an ERT manufactured by Itron. These models generally include the 40G, 100G, and 500G ERT. The 40G ERT was manufactured between 1991 and 2003 and were installed in the Company's system until approximately 2011 with the majority installed between 2006 and 2008 when the Company first retrofitted ERTs to automate its meter reading processes. These 40G ERTs range between 17 and 19 years of age. As an ERT fails, it can lead to an abrupt failure to transmit customer billing information. However, in many instances, as the ERT battery life degrades, it leads to intermittent meter consumption reads resulting in meter reading issues that can deviate over time resulting in actual consumption rates that are different than indicated through the device.

Itron indicates an expected 20-year battery life[10] for these devices and recommends a proactive program to replace ERTs, from an asset management perspective, before significant failure percentages are seen in the field. Factors that impact ERT lifespan include environmental conditions that may impact battery or circuitry life and mechanical wear. Southwest Gas currently installs the latest Itron ERT AMR technology in the form of newly produced Itron 100G and 500G ERTs. A 500G ERT is integrated into the Itron Intelis ultrasonic meter that are utilized for many new meter installations are serve as a direct replacement for mechanical diaphragm meters.

**Q. 33 Does the Company replace 40G ERTs through its current business practices?**

A. 33 Yes. The Company does replace some of its current population of 40G ERTs through its current business practices including its meter sample and exchange program and other activities where the meter and ERT are removed from the field and sent through the Company's meter shop for evaluation. However, this process is limited to the total number of 40G ERTs that are replaced in any given year. As the Company's population of 40G ERTs in its Nevada service territories reach end-of-life, a defined replacement effort is warranted to ensure accurate and reliable customer billing information.

**Q. 34 Is the Company considering technology that will allow it to shift to an Advanced Metering Infrastructure (AMI) system?**

A. 34 No. At this time, the Company has no plans to move to an AMI-based meter reading architecture. However, the Company continues to investigate new

[10] Itron 40 Series ERT Module Replacement White Paper. See Exhibit No.__(KML-4).

technologies such as ERTs with cellular capabilities that would allow two-way communications with the Company including automated transmittal of meter consumption data on a frequency determined by the Company. This technology could prove beneficial in areas such as multi-family residential, where frequent move-in/move-out reads occur, to provide operational efficiencies. Additionally, this technology could provide added safety benefits by proactively alerting the Company to high usage or temperature thresholds. This technology is currently being piloted by the Company to increase its understanding on potential use cases.

**Q. 35 How is the Company planning to address its aging population of 40G ERTs?**

A. 35 As the current population of 40G ERTs reaches end-of-life, the Company plans to replace these units with new AMR-type ERT devices to ensure accurate and reliable customer billing while exercising prudent asset management practices. The Prepared Direct Testimonies of Company witnesses Thomas W. Cardin and Christopher R. Anderson describe the planned replacement actions for the Company's ERT Replacement Program in the Southern Nevada and Northern Nevada service areas, respectively. The prepared direct testimony of Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer rate impacts related to this Company initiative currently underway.

## VIII. METER PROTECTION PROGRAM

**Q. 36 What is a meter shed?**

A. 36 A meter shed is a structurally engineered shelter that is installed above the natural gas meter that protects the meter from snow and ice loading damage. Starting in approximately 2009, the Company began requiring that all new customers and those customers which required a meter or service relocation to install a meter shed. If a customer's meter is damaged by snow and ice loading, the customer is required to install a meter shed before service is restored to the home or business.

**Q. 37 Please describe the anticipated benefits, from a safety perspective, of the installation of a meter shed in heavy snow load areas.**

A. 37 A meter shed provides structural protection to the Company's meter set and associated facilities. The installation of a meter shed can minimize or eliminate the potential damage to the Company's above ground facilities in heavy snow load areas thereby reducing the potential for a hazardous condition at the customer's premise should damage occur thus increasing safety while reducing or avoiding the potential of unintended natural gas emissions.

**Q. 38 Please describe the Company's proposed Meter Protection Program.**

A. 38 Southwest Gas operates in service areas in Nevada that are subject to heavy snow load. The Company has identified the need to implement a comprehensive and proactive program to protect the Company's meter sets from the threat of snow and ice loading damage. During the winter season of 2022/2023, the Company experienced 229 incidents and facilities damage caused by the snow and ice loading on Company meter sets in the Lake Tahoe area, of which 34 were within Nevada. These incidents highlight a need for further protection of existing Company facilities in heavy snow load areas.

Southwest Gas currently requires customers in heavy snow load areas to implement extra precautions to ensure that gas piping, meters, and outdoor appliances remain safe in heavy snow load areas. This includes the requirement for customers to install a meter snow shelter (meter shed) above the gas meter to prevent snow and ice accumulation.

The Company currently requires installation of a meter shed for all new customer meter sets and for the relocation of an existing meter or service line. . The Company provides meter shed designs on the Southwest Gas' website for customer reference. The Company currently does not require customers to retrofit their existing meter sets with a protective meter shed. The Company's proposed Meter Shed Protection Program would aim to enhance the protection of existing meters in heavy snow load areas that currently do not have an adequate form of meter protection against snow load.

**Q. 39 Please describe the Company's heavy snow load areas.**

A. 39 The Company considers its Nevada service territories along the eastern shore of Lake Tahoe located in Incline Village, Crystal Bay, Stateline, and Kingsbury, Nevada to be heavy snow load areas, these locations are typically above 6,200 feet of elevation. These areas commonly receive five (5) feet or 60 inches of snowfall or more annually.[11]

**Q. 40 Is the Company proposing to install meter sheds for all of its customers in heavy snow load areas?**

A. 40 No. The Company's proposed Meter Protection Program would focus on meter shed installations on those existing unprotected customer meters where the meter is located on the eave side of the house. The eaves are the edges of the roof which overhang the face of a wall and extend beyond the side of a building or home. The eave side of the home is generally where the highest risk of snow and ice damage occurs to a meter set assembly as it falls off the roof.

**Q. 41 Does the Company educate and make its customers aware of the potential damages from snow and ice loading on its meter sets?**

A. 41 Yes. The Company provides bi-annual notifications to its customers in heavy snow load areas, which inform of the potential risk of damage by snow and ice loads for gas piping, meter, and outdoor appliances. The Company also makes this same information available online and through local newspapers and other media channels such as radio-based public awareness messaging. A copy of the

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[11] myperfectweather.com indicates an average annual snowfall for Incline Village, NV of 135 inches collected from the National Center for Environmental Information for the period of 1991-2020.

Company's current Snow Season Safety brochure is provided as Exhibit No.__(KML-5).

**Q. 42 What is the breakdown of the Meter Protection Program costs?**

A. 42 The prepared direct testimony of Company Witness Christopher R. Anderson describes the proposed program in more detail from an operational perspective, while the prepared direct testimony of Company Witness Christopher M. Brown discusses the proposed cost recovery and estimated customer rate impacts associated with the proposed Meter Protection Program.

**Q. 43 Does this conclude your prepared direct testimony in this matter?**

A. 43 Yes.

**SUMMARY OF QUALIFICATIONS**
**KEVIN M. LANG**

Kevin M. Lang is the Vice President of Engineering Services for Southwest Gas Corporation (Southwest Gas). He leads engineering and technical support to five operating divisions and Great Basin Gas Transmission Company in the areas of pipeline safety code compliance; right-of-way and land rights acquisition and maintenance, material specifications and approval; proper energy measurement; pipeline cathodic protection; technical support of the SCADA system; project design review; hydraulic modeling and FERC project management support; the Company's integrity management programs, laboratory services, the Geographic Information System (GIS) program management; technical services support and corrosion control; and enterprise content management, in addition to oversight of the dispatch and gas control areas for both Southwest Gas and Great Basin Gas Transmission Company.

Mr. Lang joined Southwest Gas in 2003 as an engineer in Victorville, CA. Mr. Lang oversaw the design of new and replacement transmission and distribution natural gas facilities in progressive technical and leadership positions. He was promoted to Director of Gas Operation Support Staff in 2011, Director of Engineering Services in 2012, and Vice President of Engineering Staff in 2024.

He holds a Bachelor of Science degree in mining engineering from Virginia Tech and a master's degree in business administration from the University of Arizona. He is a registered Professional Engineering in the state of Arizona and Nevada with a proficiency in Civil Engineering. Mr. Lang currently serves on the American Gas Association's Managing Committee and is a member of the Board of Directors for the Gas Technology Institute Operations Technology Development (GTI OTD).

SOUTHWEST GAS CORPORATION

# *DIMP THREAT CHECKLIST*

Discovery Date February 10, 2012

Name of Threat SNV 1984-1985 2-inch high density polyethylene (HDPE) Butt Fusion Failures

**Threat Category**

- ☐ Corrosion Failure
- ☐ Natural Force Damage
- ☐ Excavation Damage
- ☐ Other Outside Force Damage
- ☐ Pipe, Weld or Joint Failure
- ☐ Equipment Failure
- ☒ Incorrect Operation
- ☐ Other Cause ____________________

Threat Description

Butt fusion failures have been experienced on 2-inch 1984-1985 HDPE pipe as a result of incorrect operation.

Additional Information

A re-evaluation of the threat associated with 1984-1985 fusion failures was conducted in August 2015. A total of seventy-six leaks were found in SNV Division from 1999-present on 2-inch M8000 and Plexco pipe. The DIMP threat checklist is being revised to address both HDPE materials installed during 1984 and 1985, and supersedes the SNV Butt Fusion Failures threat checklist approved on 4/3/2012.

Of the seventy-six leaks, sixty leaks were found in the Las Vegas Valley, twelve leaks in Bullhead City, and four leaks in Laughlin as of August 2015.

As of February 1, 2018, the risk assessment process was changed from the DPI application to the Risk Assessment application, using the procedure outlined in the DIMP Plan.

Scope

Mitigate the threat of leaks on 2-inch 1984 and 1985 HDPE butt fusions in SNV

Analysis

Analysis indicates 2-inch 1984-1985 HDPE materials are susceptible to butt fusion failures due to incorrect operation.

**Location of Threat**

Division SNV District 21 and 34

City Las Vegas, Laughlin, and Bullhead City Location Description Multiple locations

Address or GPS Coordinate

Number of Failures (approximate) 76 (August 2015)

Potential Risk High

Rationale of Risk Choice

Fusion failures have the potential to release large quantities of gas.

**Risk Mitigation Plan**

Step 1
Leak surveys of 2-inch mains in the Las Vegas Valley and 2-inch services in the Las Vegas Valley, Laughlin and Bullhead City will take place 4 times a year, not to exceed 4-1/2 months.

This mitigation step will not apply to 2-inch mains in Laughlin and Bullhead City. These facilities are already being covered through the M7000/M8000 mobile patrol frequency for HDPE mains in Laughlin and Bullhead City.

Step 2
Leak Risk Assessment on 2-inch 1984-1985 HDPE segments that experience a butt fusion failure will take place within 30 days of discovery. Based on the resulting Leak Risk Assessment value, the installation work request of the leaking 2-inch pipe will be replaced in accordance with the DIMP Plan.

Step 3

Start Date _October 1, 2015 Estimated Duration until 1984-1985 HDPE is replaced

Additional Information

Performance Measure
Leak count for 1984 and 1985 2-inch HDPE materials
Miles of pipe remaining

Start Date _2015 Monitoring Duration Annually

**Approval**

Approved By Joel Martell Date Approved January 26, 2018

*DIMP Manager Signature*

# National Transportation Safety Board

Office of the Chairman
Washington, DC 20594

April 8, 2025

The Honorable Joe Lombardo
Governor of Nevada
State Capitol Building
101 N. Carson St.
Carson City, NV 89701

Dear Governor Lombardo:

The National Transportation Safety Board (NTSB) is an independent federal agency charged by Congress with investigating every civil aviation accident in the United States and significant accidents in other modes of transportation—railroad, highway, marine, and pipeline. We determine the probable cause of the accidents and issue safety recommendations aimed at preventing future accidents. In addition, we carry out special studies concerning transportation safety and coordinate the resources of the federal government and other organizations to assist victims and their family members affected by major transportation disasters.

We are providing the following information to urge the State of Nevada to act on the safety recommendation in this letter because we believe your organization can help reduce the risk of future accidents. For more information about the NTSB and our recommendation process, please see the attached one-page summary.

This letter also includes information about our March 18, 2025, report, *UGI Corporation Natural Gas-Fueled Explosion and Fire, West Reading, Pennsylvania, March 24, 2023*, NTSB/PIR-25/01. The details of this accident investigation and the resulting safety recommendations may be found in the attached report, which can also be accessed at http://www.ntsb.gov.

As a result of this investigation, we identified the following safety issues:

- Degradation of a retired Aldyl A service tee that was accelerated by elevated ground temperatures from a corroded and cracked steam pipe nearby.
- UGI Corporation's insufficient consideration of pipeline integrity threats, particularly Aldyl A service tees with Delrin inserts at elevated temperatures.
- Presence of unmarked and unreported private assets crossing public rights-of-way, excluding them from the Pennsylvania One Call System and increasing the risk of damage to them.

- Delayed evacuation of Palmer's Building 2 despite detection of natural gas by employees and others.
- Natural gas safety messaging from pipeline operator public awareness programs that may not reach certain members of the public.
- Insufficient guidance on natural gas emergency procedures.
- Absence of natural gas alarms in commercial buildings.
- Insufficient accessibility of gas distribution line valves.

Accordingly, the NTSB makes the following safety recommendation to the State of Nevada (additional information regarding this recommendation can be found in the noted section of the report):

- Require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak. (P-25-5) (See section 2.5.1.)

The NTSB is vitally interested in this recommendation because it is designed to prevent accidents and save lives. We would appreciate a response within 90 days of the date of this letter, detailing the actions you have taken or intend to take to implement this recommendation. When replying, please refer to the safety recommendation by number (Safety Recommendation P-25-5). We encourage you to submit your response to ExecutiveSecretariat@ntsb.gov. If your reply, including attachments, exceeds 20 megabytes, please e-mail us at the same address for instructions on how to send larger documents. Please do not submit both an electronic copy and a hard copy of the same response.

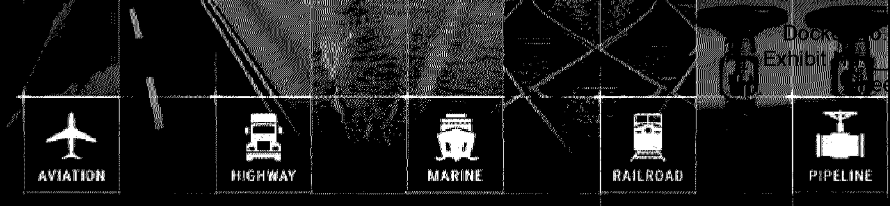
All communications regarding safety recommendations are stored by the NTSB and viewable by the public. Please do not send privileged or confidential communications in response to this recommendation. Responses marked as confidential or privileged (or similar designations) will be considered nonresponsive. In the likely event that your organization uses auto-generated and/or preformatted confidentiality statements on letterhead or outgoing e-mails, please include a statement in your letter indicating that the information can be publicly released. If you have concerns about this protocol, please contact us at ExecutiveSecretariat@ntsb.gov.

Sincerely,

Jennifer L. Homendy

Jennifer L. Homendy
Chairman
On behalf of the entire Board

cc: Ryan Cherry
Chief of Staff, Nevada Governor Joe Lombardo






# UGI Corporation Natural Gas-Fueled Explosion and Fire

## West Reading, Pennsylvania
## March 24, 2023

**Abstract:** This report discusses the March 24, 2023, natural gas–fueled explosion and fire at Building 2 of the R.M. Palmer Company, a candy manufacturer located in West Reading, Pennsylvania. The explosion destroyed the manufacturer's Building 2 and caused significant structural damage to its adjacent Building 1 and other surrounding structures. In total, 7 people were killed, 10 people were injured, and 3 families were displaced from a neighboring apartment building.

Safety issues identified in this report include degradation of a retired service tee, insufficient consideration of threats to pipeline integrity, the risk associated with unmarked private pipeline assets crossing public rights-of-way (for example, a public street), delayed evacuation of Building 2 despite detection of natural gas, natural gas safety messaging that may not reach certain members of the public, insufficient guidance on gas leak emergency procedures, absence of natural gas detection alarms in commercial buildings, and insufficient accessibility of gas distribution line valves.

As part of this investigation, the National Transportation Safety Board issued recommendations to the Pipeline and Hazardous Materials Safety Administration, the Occupational Safety and Health Administration, 50 states along with the Commonwealth of Puerto Rico and the District of Columbia, the Commonwealth of Pennsylvania, the Pennsylvania Public Utility Commission, the American Gas Association, the American Petroleum Institute, the Gas Piping Technology Committee, the Common Ground Alliance, the International Code Council, the National Fire Protection Association, UGI Corporation, and R.M. Palmer Company.

# Contents

# Figures

# Tables

# Acronyms and Abbreviations

| | |
|---|---|
| API | American Petroleum Institute |
| CEO | Palmer Chief Executive Officer |
| *CFR* | *Code of Federal Regulations* |
| CGA | Common Ground Alliance |
| DDRM | data-driven risk model |
| GOM | *Gas Operations Manual* |
| DIMP | distribution integrity management program |
| GIS | geographic information system |
| GPTC | Gas Piping Technology Committee |
| GPTC Guide | *Guide for Gas Transmission, Distribution, and Gathering Piping Systems* |
| ICC | International Code Council |
| IFC | International Fuel Code |
| IFGC | International Fuel Gas Code |
| IM | integrity management |
| Inside SLIP | inside service line inspection program |
| NFPA | National Fire Protection Association |
| NFPA 54 | National Fuel Gas Code |
| NPRM | notice of proposed rulemaking |
| OSHA | Occupational Safety and Health Administration |
| PA One Call | Pennsylvania One Call System |
| PA PUC | Pennsylvania Public Utility Commission |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| psig | pounds per square inch, gauge |
| PSMS | pipeline safety management system |
| RP | Recommended Practice |
| SME | subject-matter expert |
| VP | Palmer vice president of operations and technical services |

# Executive Summary

## What Happened

On March 24, 2023, around 4:55 p.m., natural gas, which was transported through a UGI Corporation–owned pipeline, leaked into and accumulated in the basement of an R.M. Palmer Company candy factory building in West Reading, Pennsylvania. The gas ignited, causing an explosion and fire that killed 7 Palmer employees, injured 10 people, and destroyed the building. Another Palmer building, as well as an adjacent apartment building, were also severely damaged. Three families were displaced from the apartment building.

## What We Found

In 2021, a UGI Corporation crew retired the Aldyl A polyethylene service tee, joining UGI's gas main to the service line for Palmer Building 2. The crew capped off the retired tee, which had been installed in 1982, and installed a new tee. The retired Aldyl A tee remained connected to the natural gas distribution system. We found that natural gas had migrated from the retired Aldyl A service tee through the ground then into the Palmer Building 2 basement, chocolate pipe conduits, and Building 1, and fueled the explosion in the Building 2 basement. We found that the 1982 retired service tee leaked because of degradation (slow crack growth of the Aldyl A tower shell and thermal decomposition of the Delrin insert) caused by exposure to elevated temperatures. Steam escaping through a crack in a corroded steam pipe nearby had significantly elevated the ground temperatures near the tee. We found that the omission from PA's One Call law of certain assets whose lines transport steam or other high temperature substances across public rights-of-way can pose a risk during nearby excavation. We further found that widespread adoption of best practices on 811 center membership can increase awareness of certain underground pipelines that cross public rights-of-way and prevent an accident like this one.

We found that, without sufficient threat information available for analysis in its distribution integrity management program (DIMP), UGI could not effectively evaluate and address the risk to pipeline integrity of plastic piping in elevated temperature environments and that by not addressing the threat posed by the steam pipe, UGI's DIMP was not effective in preventing the accident. We further found that operators may not be aware of where they may have plastic natural gas assets that are vulnerable to degradation in elevated temperature environments, so appropriate mitigations may not be in place. In this accident, we found that UGI lacked procedures and training for its field crews to report sources of elevated temperatures near their assets thus the threat posed by the steam pipe was not identified, and mitigative measures were not implemented. In addition, industry guidance highlighting the threat to pipeline integrity of exposure to elevated temperatures could improve awareness so that operators can effectively identify and manage the threat.

Although several employees reported smelling the gas in the buildings before the explosion, few evacuated. We found that had Palmer implemented natural gas emergency procedures and training before the accident, employees and managers could have responded by immediately evacuating and moving to a safe location. We further found that when businesses that use natural gas do not have natural gas emergency procedures and training, employees may be unaware or unsure of what to do if they smell natural gas. Further, we determined that natural gas alarms can alert people of a gas leak so they can evacuate the area; however, natural gas customers may not be aware of the necessity of such alarms. We also found that, because of their consensus-based nature and wide reach, model building or gas codes can be effective instruments to address natural gas–related risks to employees of businesses that use natural gas. Because adoption of these fuel gas codes and other rules related to natural gas alarms depends on state and local policies, widespread requirement of natural gas alarms will rely on action at the state and local level.

We found that natural gas pipeline operator public awareness programs may not reach certain members of the public who do not directly receive bill stuffers, making them potentially unaware of natural gas safety guidance. Further, because customers vary significantly in the number of occupants or residents, criteria for designating emergency valves that only count customers may not accurately reflect who could be affected by a natural gas outage or emergency or the severity of the effect. We also found that UGI did not effectively inspect and maintain its valves through its valve maintenance program, which led to a delay in shutting off gas to the affected area. Lastly, we found that the Pennsylvania Public Utility Commission refused to provide investigative information pursuant to the NTSB's federal authority.

We determined that the probable cause of the explosion was degradation of a retired 1982 Aldyl A polyethylene service tee with a Delrin polyacetal insert that allowed natural gas to leak and migrate underground into the R.M. Palmer Company candy factory buildings, where it was ignited by an unknown source. Contributing to the degradation of the service tee and insert were significantly elevated ground temperatures from steam escaping R.M. Palmer Company's corroded underground steam pipe, located near the service tee, that had been unmarked and cracked. Contributing to the steam pipe crack was soil movement and R.M. Palmer Company's lack of awareness of the pipe's corroded state. Contributing to the natural gas leak was UGI Corporation's lack of awareness of the nearby steam pipe, which led to an incomplete integrity management program evaluation that did not consider or manage the risk posed by the steam pipe. Contributing to the accident's severity was R.M. Palmer Company's insufficient emergency response procedures and training of its employees, who did not understand the hazard and did not evacuate the buildings before the explosion.

## What We Recommended

We recommended that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issue an advisory bulletin reviewing the details of this accident to natural gas distribution pipeline operators and advising them to address the risk associated with Aldyl A service tees with Delrin inserts by replacing or remediating them. We also recommended that PHMSA issue an advisory bulletin to operators referencing DIMP regulations and encouraging a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures, identifying plastic assets in elevated temperature environments, and evaluating and mitigating risks to deter the degradation of these assets. In addition, we recommended that UGI inventory all its plastic natural gas assets that may be in elevated temperature environments and address the risk associated with these assets. We reiterated a 2021 recommendation to PHMSA to evaluate industry implementation of gas distribution pipeline integrity management requirements and develop updated guidance for improving the effectiveness of the requirements.

We further recommended that PHMSA find effective ways for operators to communicate with people who live, work, or congregate near natural gas distribution pipelines and help operators improve public awareness of natural gas safety. We then recommended that, based on these findings, the American Petroleum Institute update its public awareness standard to provide specific guidance to natural gas distribution pipeline operators on effective safety communications.

We recommended that the Occupational Safety and Health Administration require employers whose facilities use natural gas to implement natural gas emergency procedures and that Palmer revise its natural gas emergency procedure to direct all employees to immediately evacuate to a safe location when they smell natural gas. We also recommended that Pennsylvania modify its law on underground utility protection to require all owners and operators of pipelines transporting steam or other high-temperature materials located in public rights-of-way to register their assets with Pennsylvania One Call and that the Common Ground Alliance identify opportunities for improving adoption of its best practices on 811 center membership. To make sure operators consider consequences and emergency response times in determining the locations of critical valves, we recommended the Pennsylvania Public Utility Commission assess operators' methodology for this determination.

We recommended that the American Gas Association share the details of this accident with its members, encouraging them to evaluate the effectiveness of their public awareness programs and to promote the installation of natural gas alarms. We also recommended that the Gas Piping Technology Committee develop guidance to ensure natural gas pipeline operators' DIMPs appropriately assess and address threats to plastic pipelines from nearby temperature-elevating assets.

We recommended that 50 states, Puerto Rico, and the District of Columbia require the installation of natural gas alarms and that the International Code Council and the National Fire Protection Association revise codes to provide for natural gas emergency procedures and revise the fuel gas codes to provide for the required installation of natural gas alarms.

Finally, we recommended that the Commonwealth of Pennsylvania review and amend its statutes to facilitate sharing investigative information with the NTSB.

# 1 Factual Information

## 1.1 The Accident

On March 24, 2023, about 4:55 p.m. local time, a natural gas–fueled explosion and fire occurred at Building 2 of the R.M. Palmer Company candy factory in West Reading, a borough in Berks County, Pennsylvania. The explosion destroyed Building 2 and caused significant structural damage to the adjacent Building 1 and other surrounding structures, including an apartment building. (See figure 1.) In total, 7 people were killed, 10 people were injured, and 3 families were displaced from their apartments. The accident caused an estimated $42 million in property damage.[1] Weather conditions at the time of the accident were clear with no precipitation, the temperature was 52°F, and winds were about 5 mph from the southwest by south.

[1] Visit ntsb.gov to find additional information in the public docket for this NTSB accident investigation (case number PLD23LR002). Use the CAROL Query to search safety recommendations and investigations.

**Figure 1.** Overhead image of the accident. (Source: Western Berks Fire Department.)

### 1.1.1 Area Layout

Building 2, a two-story brick structure, was located at 17 South 2nd Avenue in West Reading. The four-story brick Building 1 was located at 77 South 2nd Avenue, south of Building 2. Cherry Street, a public right-of-way (alley), separated the two buildings. The affected apartment building, which comprised three households, was located 5 feet north of Building 2. (See figure 2.)

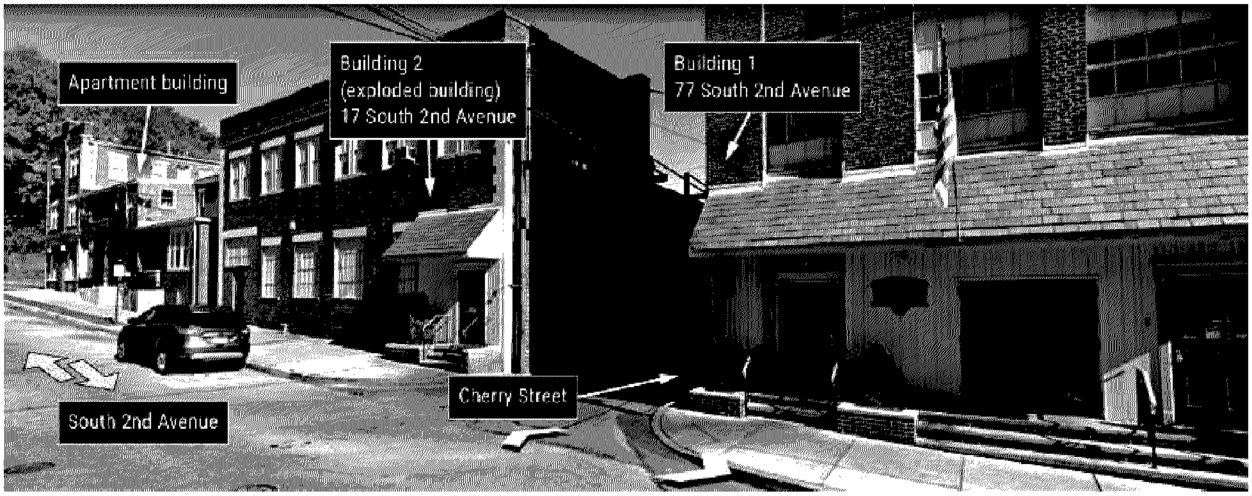


**Figure 2.** South 2nd Avenue before the accident. (Source: Google Photos.)

UGI Corporation owned and operated natural gas pipeline assets located within the public right-of-way near the accident site.[2] Natural gas was distributed to Palmer Buildings 1 and 2 from a UGI natural gas main that ran lengthwise underneath Cherry Street (Cherry Street main).[3] Near the intersection with South 2nd Avenue, the Cherry Street main transitioned from a short section of steel and then reduced to a 1.25-inch-diameter Aldyl A main, which was installed in 1982 (see section 1.5.1).[4] Aldyl A is the trademarked name of a polyethylene plastic gas pipeline product that was manufactured by the DuPont chemical company using a proprietary polymer resin. At the time of the accident, the Cherry Street main was operating about 53 pounds per square inch, gauge (psig). The maximum allowable operating pressure of the Cherry Street main was 60 psig. The main was about 3 feet below the road surface.

Palmer produces chocolate novelty candies for sale in the United States and internationally and has been in business in Pennsylvania since 1948. It has about 550 full-time employees and about 300 seasonal workers. Palmer's facilities at the time of the accident comprised six buildings, two in West Reading and four in Wyomissing,

[2] (a) See section 1.5 for UGI company information. (b) This report uses the term *asset* to refer to the specific elements of a pipeline distribution system.

[3] A *gas main* is a natural gas distribution pipeline that serves as a common source of supply for more than one service line. *Service lines* transport gas to a customer.

[4] In 1982, the Aldyl A gas main was installed by inserting it into a bare steel main from 1911. As was common practice at the time, once the Aldyl A main was inserted, the steel main was then abandoned. An *abandoned* pipeline is one permanently removed from service, no longer containing natural gas, as defined in Title 49 *Code of Federal Regulations* (*CFR*) 192.3.

Pennsylvania. In West Reading, Building 1 was used for candy production and as corporate headquarters, and Building 2 was used for candy production. Palmer-owned pipes (private pipes) ran underneath Cherry Street between Buildings 1 and 2: a steam pipe that delivered steam from the boiler to heat areas of Building 2, a condensate pipe that channeled condensation back to the boiler, and two conduits that together contained six supply pipes that delivered liquid chocolate from storage tanks in the basement of Building 2 to production areas in Building 1.[5] One conduit contained four chocolate supply pipes, and the other conduit contained two chocolate pipes. (See figure 3.) Electric heat tape affixed to the outside of the chocolate pipes kept the chocolate from solidifying in the pipes. The top of the steam pipe was about 1.5 feet below the road surface.[6]

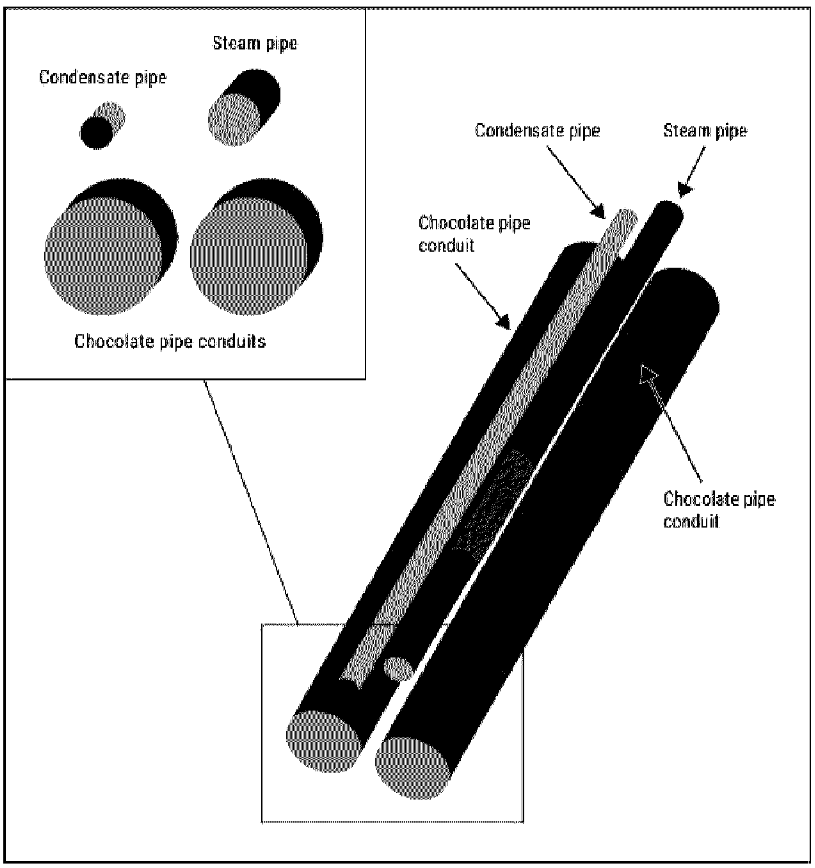



**Figure 3.** Arrangement of Palmer-owned pipes.

[5] These pipes were partially destroyed in the explosion and are no longer in use.

[6] Palmer began production in Building 2 in the mid-1960s. The National Transportation Safety Board (NTSB) interviewed a former Palmer employee who indicated the steam pipe had been installed before he began working there in the mid-1970s.

The Palmer-owned pipes laid above and perpendicular to the gas main, with steam flowing from Building 1 to Building 2. Palmer kept maintenance records of the steam heating system boiler unit. These records indicated that the unit was checked daily by Palmer mechanics and inspected annually by a contractor, but Palmer did not have any maintenance records for the steam pipe to Building 2.

### 1.1.2 Service Line and Tee Replacement at Palmer Building 2

Two years before this accident, on February 16, 2021, a UGI crew conducted a routine inspection of the Building 2 gas meter, which at the time was in the basement.[7] The crew detected gas inside the basement of Building 2 and at the service curb valve outside the building. UGI recorded this as a "grade C" leak, which required immediate attention or repair, and began a project to replace the service line and service tee from the Cherry Street gas main to Building 2 and to move the meter outdoors as required by UGI procedures. The service tee joined the service line to the main. The alignment of the private pipes and natural gas distribution system assets after the replacement project is shown in figure 4.

[7] This type of inspection, required by UGI's *Gas Operations Manual* (GOM) and federal regulation to be conducted every 3 years on a medium-pressure system, is described further in section 1.5.2.

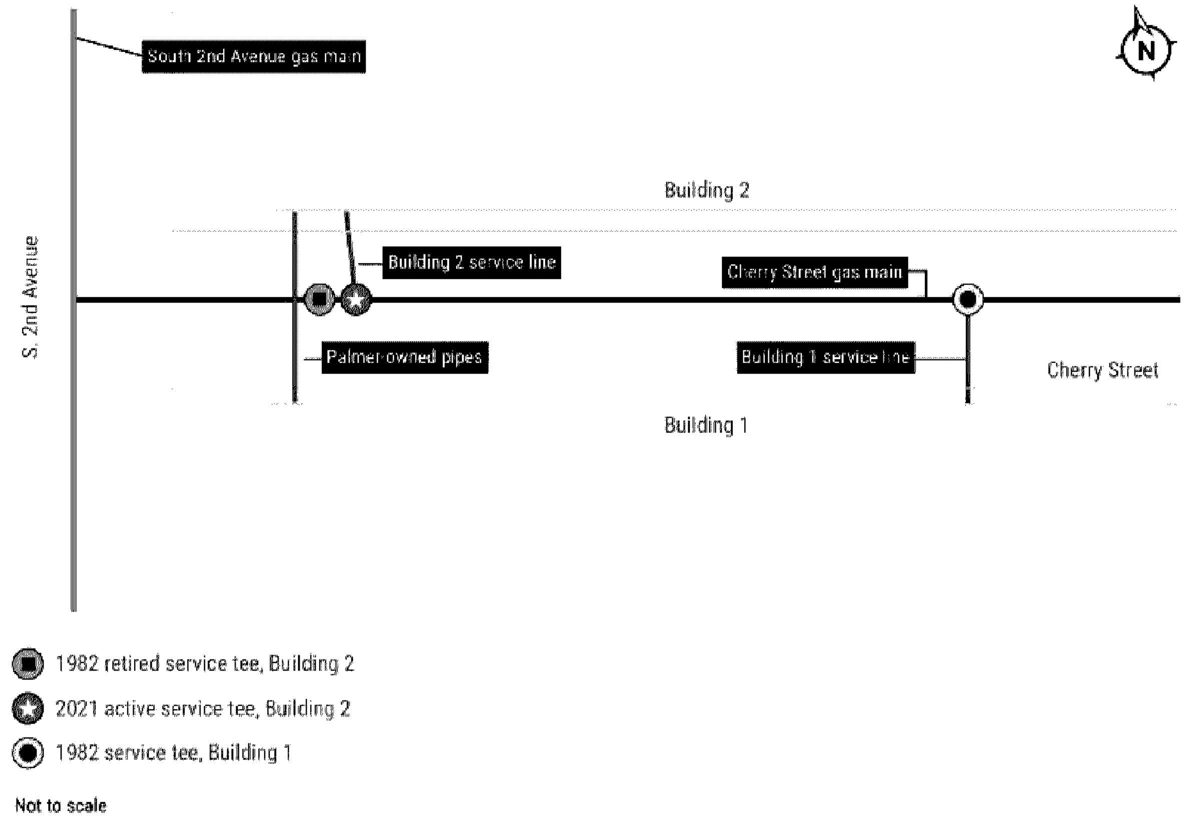



**Figure 4.** Natural gas distribution system and Palmer-owned pipes.

Before beginning excavation to replace the service line and move the gas meter, UGI submitted an emergency underground utility line locate request to the Pennsylvania One Call System (PA One Call) to mark existing utilities so UGI could repair a gas leak at Building 2.[8] Pennsylvania's Underground Utility Line Protection Law, Pennsylvania Act 287, as amended, requires owners or operators of underground lines that serve one or more customers or consumers in Pennsylvania to be a member of PA One Call, a privately funded nonprofit corporation that facilitates utility line location in all Pennsylvania counties.[9] PA One Call's interpretation of this law did not require Palmer to be a member, so its underground pipes were not included in the PA One Call database.

[8] Pennsylvania has recognized and adopted the uniform pavement marking colors outlined in the Common Ground Alliance's *Best Practices Guide* for underground piping or other utility assets.

[9] See Pennsylvania Statutes, Title 73 P.S. Section 176 et. Seq.

After the accident, the NTSB interviewed UGI crewmembers about the 2021 replacement of the Building 2 service line. A member of the UGI crew recalled seeing a subsurface white powder during excavation, located west of the service tee that they were replacing. The crewmember said that a Palmer employee came to the excavation site and indicated there was a steam pipe in the ground near or next to the white powder, the purpose of which was unknown. The UGI crewmember stated that he did not observe the steam pipe itself.

The crew did not attempt to expose the steam pipe to determine the actual location of the pipe or its distance from natural gas assets and did not notify UGI integrity management staff of a steam line in the vicinity of the assets. Palmer was not a PA One Call member, and was not required to be, so the locations of their underground pipes had not been marked.

The crew continued the excavation and completed the retirement of the original service line and tee and installation of the new service line and tee to the east of the old ones.[10] (See section 1.5.1 for a description of the typical process.) (See figure 5.) Upon completion of the project, the 1982 service line stub and tee remained attached to the gas main and exposed internally to full gas system pressure. UGI's standard and common industry practice for replacement of a service line and tee is to cap the tee and leave the tee attached to the main, exposed to full gas system pressure, and to install a new tee and service line nearby.

[10] This report uses the term *retired* to describe a natural gas asset that is no longer in use but that still contains natural gas. In this accident, the 1982 Aldyl A service tee to Building 2 was retired, therefore it is referred to in the report as the *retired service tee*.

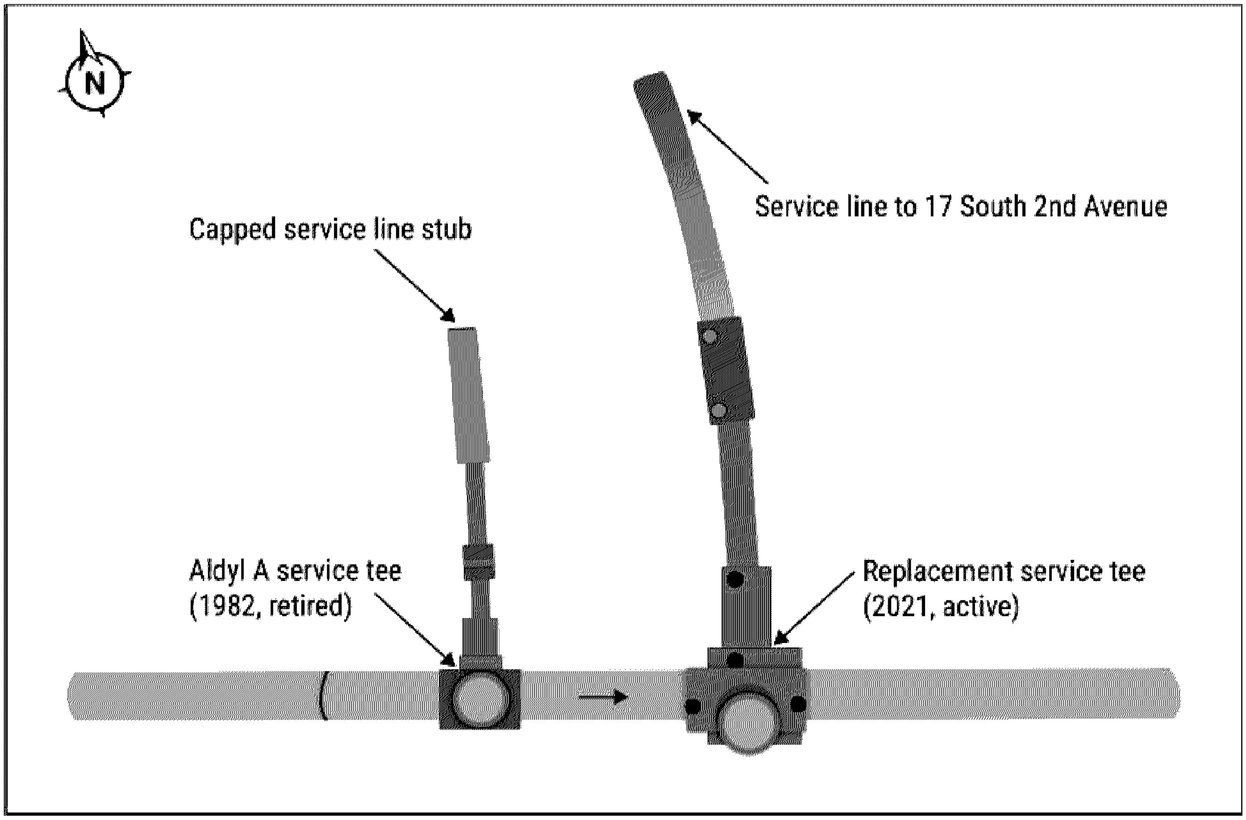



**Figure 5.** Cherry Street gas main and Building 2 service tees, viewed from above.

A review of PA One Call records indicated that no further work exposed the original service tee after February 16, 2021.

### 1.1.3 Natural Gas Leak and Explosion

On March 24, 2023, about 1.5 hours into the second shift at Palmer's West Reading facilities, employees in and around Buildings 1 and 2 began to smell natural gas odors, and some reported the smell to their supervisors.[11] Employees described

[11] Palmer production employees worked in shifts: the first shift was from 7:00 a.m. to 3:00 p.m., the second from 3:00 p.m. to 11:00 p.m., and the third from 11:00 p.m. to 7:00 a.m. In postaccident interviews with the NTSB, first-shift Palmer employees working in both Buildings 1 and 2 on March 24 did not recall a strange odor or one associated with natural gas.

this odor in various ways. Some identified it as a natural gas odor, others described it as a peculiar or strange odor.[12]

#### 1.1.3.1 Building 1

About 65 employees, both production and office workers, were working in Building 1 at the time of the accident, with candy in production at that location. Several second-shift Palmer employees, working on the third and fourth floors in production areas that faced Cherry Street, told the NTSB they reported a gas odor to the second-shift supervisor between 4:20 and 4:46 p.m.[13] Some employees recalled that the second-shift supervisor told them they could go home early, but they told the NTSB they were concerned leaving would count against their workplace attendance.[14] In a postaccident interview with the NTSB, the second-shift supervisor stated she did not smell gas before the explosion. They did not leave the building before the explosion.

The Palmer receptionist, who worked in Building 1, told the NTSB that about 4:45 p.m., another employee who had already left for the day called from her car and notified the receptionist of a peculiar smell outside between Buildings 1 and 2, which the employee could not identify.

A custodian working the second shift in Building 1 told the NTSB that he smelled gas a little after 4:30 p.m. and reported it to the receptionist and his supervisor some time later.[15] He recalled asking his supervisor if she was going to leave the building on account of the natural gas odor. The supervisor responded that she was not going to leave, and she thanked him for letting her know about the odor. The custodian then self-evacuated from Building 1. Palmer management did not evacuate Building 1 before the explosion, and no employees pulled the fire alarm.

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[12] Because natural gas is odorless, strong-smelling chemical additives called odorants are mixed with natural gas before distribution to help reduce the risk that leaks will go unidentified. The most common odorant added to natural gas is methanethiol, or methyl mercaptan, which has a characteristic "rotten egg" or sulfurous odor.

[13] These employees estimated the reporting times based on their second shift's typical break time.

[14] According to interviews with Palmer employees, the company's attendance policy penalized unreported or unexcused absences and leaving early from a shift.

[15] The Palmer receptionist did not confirm this report when interviewed by the NTSB.

#### 1.1.3.2 Building 2

During the second shift, seven production employees were assigned to Building 2 in West Reading to clean and change over candy production equipment. The second shift employees who had worked in or entered Building 2 on the day of the accident told the NTSB that they did not smell gas at the beginning of their shift, about 3:00 p.m.

An assistant line technician working on the first floor of Building 2 told the NTSB that, about 4:30 p.m., he and his team leader, the lead line technician, heard the second-shift production employees working on the first floor of Building 2 complaining of a gas smell. The assistant line technician stated that he and the lead line technician went to the area of the complaint, where they too smelled a gas odor. He added that he self-evacuated from Building 2 soon after arriving there, because the smell of gas was strong enough to hurt his eyes, causing him physical pain.

An employee who packaged chocolates (packer) was one of the production employees working on the first floor of Building 2 who had complained of the gas smell. In an interview with the NTSB, the Building 2 packer recalled the lead mechanic entering Building 2 and saying he had smelled “a very strong gas smell” in that building and in Building 1. The packer stated that the lead mechanic then exited Building 2 to find out more about the gas odor. The lead line technician exited the building around the same time. The Building 2 packer and four other production employees remained inside; the packer stated that at the time of the accident, her understanding of employee protocol during such a situation was that they must stay at their workstations and await instructions from a supervisor. She told the NTSB she had worked at Palmer for 4 years.

The NTSB reviewed surveillance camera data of Buildings 1 and 2 just before the explosion. Table 1 shows times and employee movements.

**Table 1.** Surveillance camera data from in and around Buildings 1 and 2 before the explosion.

| Time[1] | Location | Description |
|---|---|---|
| 4:42 p.m. | Building 1 | Palmer receptionist received call from an off-duty employee who reported a strong odor outside the buildings |
| 4:42 p.m. | Building 2 | Lead mechanic entered Building 2 |
| 4:43 p.m. | Building 2 | Assistant line technician exited Building 2 |
| 4:44 p.m. | Building 2 | Lead mechanic exited Building 2 and met with lead line technician |
| 4:47 p.m. | Cherry Street | Lead mechanic and lead line technician looked at the gas meter, which was attached to the southwest wall of Building 2 facing Cherry Street |
| 4:49 p.m. | Building 1 | Custodian had discussion with receptionist, motioning to his head and face |
| 4:52 p.m. | Cherry Street | Truck driver looked at gas meter with lead mechanic |
| 4:53 p.m. | Cherry Street | Plant manager and lead mechanic looked at gas meter and sidewalk below it |
| 4:54 p.m. | Building 2 | Plant manager and lead mechanic entered Building 2 through basement door on Cherry Street |
| 4:54 p.m. | Cherry Street | Human resources director looked at gas meter and sidewalk below it |
| 4:55 p.m. | Building 2 | Human resources director appeared to be smelling the area as she entered Building 2 through front door; lead line technician held door for her |
| **4:55 p.m.** | **Building 2** | **Explosion** |

A truck driver who was on Cherry Street delivering liquid chocolate by hose into Building 1 told the NTSB that, while working around his truck, he smelled an unfamiliar odor. He discussed it with the Palmer lead mechanic, who was standing outside Building 2 with the Palmer plant manager; the truck driver recalled the lead mechanic suggesting the odor could be "raw sewage" or "methane."[16] The truck driver told the NTSB that the lead mechanic and plant manager entered the

[16] Methane is the primary component of natural gas.

basement of Building 2 just before the explosion. Palmer management did not evacuate Building 2 before the explosion, and no employees pulled the fire alarm.

## 1.2 Injuries and Damages from the Explosion and Gas Fire

The explosion killed seven Palmer employees.[17] Six died from blast injuries and one from extensive thermal burns. All were in Building 2 at the time of the explosion.

Three Palmer employees and the truck driver sustained serious injuries in the blast and subsequent fire. One of these three Palmer employees, the Building 2 packer, was inside Building 2 at the time of the explosion. The other Palmer employees who sustained serious injuries, the lead line technician and assistant line technician, were positioned near Building 2's front entrance, and the truck driver was on Cherry Street. Three Palmer employees near the buildings received minor injuries. Three bystanders, who assisted the injured after the explosion, also received minor injuries. The explosion destroyed Building 2 and severely damaged Building 1.

## 1.3 Emergency Response

A total of 30 fire and rescue companies, 15 law enforcement agencies, 9 emergency medical services, and 2 local urban search and rescue companies responded to the accident. The Pennsylvania Emergency Management Agency sent a supporting task force.[18] Before the NTSB launched an official investigation on March 28, various federal and state agencies, along with UGI, also responded.[19]

[17] The Palmer plant manager, human resources director, and lead mechanic, as well as four of the production employees working on the first floor of Building 2, were killed in the explosion.

[18] Pennsylvania Task Force 1, which is coordinated through the Philadelphia Fire Department, is one of 28 Federal Emergency Management Agency Urban Search & Rescue response teams.

[19] (a) Federal and state agencies included the Pipeline and Hazardous Materials Safety Administration (PHMSA), the US Chemical Safety and Hazard Investigation Board; the Occupational Safety and Health Administration (OSHA); the Bureau of Alcohol, Tobacco, Firearms and Explosives; and the Pennsylvania Public Utility Commission (PA PUC). (b) The NTSB sent an investigator on March 25, 2023, to monitor the accident in person. Once the NTSB determined it had jurisdiction over the investigation according to 49 U.S.C. 1131(a)(1)(D), it officially launched investigators on March 28. The NTSB has jurisdiction over certain natural gas pipeline accidents occurring while natural gas is in transportation, rather than those originating from customer-owned piping or appliances within a building.

### 1.3.1 R.M. Palmer Emergency Response

A Palmer packer who had been working the second shift on the third floor in Building 1 told the NTSB that, when the explosion occurred, the north wall of Building 1 seemed to explode and cause the floor to crack. After the explosion, she recalled that people began to run and that many people were screaming. Alarms went off throughout Building 1, and the Building 1 packer ran with other employees toward the building exits. A mechanic, also working in Building 1, stated that the building shook from the explosion, causing many employees to fall to the ground. The mechanic added that he shouted for people to get out of the building as he and other employees ran toward the exits. All staff who had been working in Building 1 exited to the parking lot, where an employee conducted a headcount. Building 2 was destroyed.

### 1.3.2 Local Emergency Response

Around 4:56 p.m., personnel from the City of Reading Fire Department, a half mile away from the Palmer buildings, heard the explosion and self-dispatched to the accident scene to suppress the fire and search for victims in the building rubble. The Berks County Department of Emergency Services received the first 9-1-1 call about the explosion at 4:57 p.m. The West Reading, Wyomissing, and Spring Township Fire Departments also arrived to assist with extricating victims. In a postaccident interview with the NTSB, a City of Reading Fire Department deputy chief recalled seeing heavy fire coming from the rubble of Building 2, with flames more than 40 feet high extending through the pile of debris.

Around 5:00 p.m., the City of Reading Fire Department requested that UGI respond to the incident. About 13 minutes later, the City of Reading fire chief reported fire under the sidewalk pavement near Building 2. Incident command was transferred around 5:21 p.m. from the City of Reading to the West Reading fire chief, who later told the NTSB he smelled gas and observed flash fires over the firefighters as they moved through the rubble.[20] Firefighters from the West Reading Fire Department searched Building 1 after hearing reports of a possible gas leak. They reported a gas-fed fire in the basement of Building 1, coming from an underground

[20] Three incident commanders worked alongside one another as a unified command to manage different response operations. The West Reading Fire Chief took command of the fire and rescue scene. The West Reading Police Chief secured the area, accounted for employees, and blocked traffic. Personnel from Western Berks Ambulance handled incident command for the emergency medical services.

conduit (carrying the chocolate pipes) that ran beneath Cherry Street between Buildings 1 and 2.

The West Reading fire chief recalled that after the explosion, UGI had reported problems closing underground gas main valves to isolate the gas system or stop the flow of gas feeding the fire (see section 1.3.3 for further details).[21] After the natural gas system was isolated around 6:15 p.m., the main fire went out, and firefighters extinguished the remaining pockets of fire. Emergency response personnel also rescued five people from the apartments next to Palmer Building 2.

Search and rescue operations continued for 3 days through March 27, 2023, when the last accident victims were found.

### 1.3.3 UGI Emergency Response

After the explosion, UGI worked to isolate the gas system in the area of the accident. The first UGI employee to respond to the accident was a mechanic who had been working nearby. In an interview with the NTSB, he recalled that UGI dispatch called to notify him of the explosion and that he arrived at the incident location around 5:19 p.m. He received valve identification numbers over the phone and was directed to shut off two underground gas main valves near the exploded building.

The UGI mechanic closed the first valve, at South 2nd Avenue and Franklin Street, about 5:30 p.m. (Figure 6 shows the locations of the valves UGI closed or attempted to close in response to the accident.) He recalled that when he went to the second valve at South 2nd Avenue and Penn Avenue, the valve identification number that he had received did not match the valve itself. A UGI representative later stated that the South 2nd Avenue and Penn Avenue valve was inaccessible and paved over and that consequently this valve was not closed during the response. [22] The UGI representative stated later that personnel tried to verify the gas valve's identification numbers and were unable to do so. At the time, they were not viewing the paved-over gas valve but instead a water valve that, for an undetermined reason, had a gas valve cover. UGI had designated this valve, and all the other valves it closed or

[21] *Valves* are closed to isolate a pipeline segment.

[22] It is not typical practice for a gas valve to be paved over.

attempted to close during its response to the accident, as secondary valves.[23] More information on inspections of these valves can be found in section 1.5.3.

UGI added that upon encountering this issue, the UGI mechanic used geographic information system (GIS)–based maps and records to identify the next-closest valve needed to isolate the main segment; this valve was located at South 3rd Avenue and Penn Avenue. The UGI mechanic subsequently closed the South 3rd Avenue and Penn Avenue valve about 5:50 p.m., shutting off gas flowing north to south. He then moved to the final valve at South 4th Avenue and Penn Avenue that, when closed, shut off gas flowing west to east and completed the isolation of the gas system in the affected area.

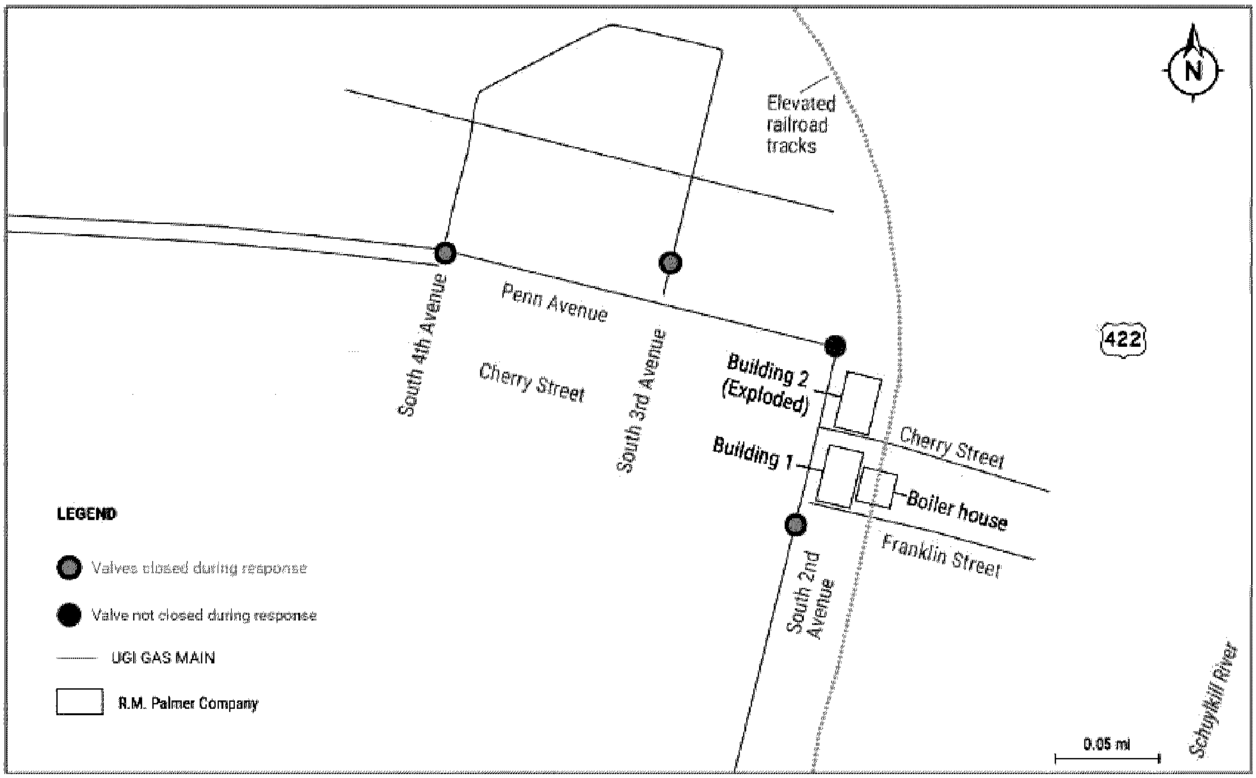


**Figure 6.** Underground gas main valves involved in response to the March 24 incident.

[23] (a) UGI referred to the valves necessary for the safe operation of a distribution system, as specified by 49 *CFR* 192.747, as *critical valves* and those not necessary for the safe operation of a distribution system as *secondary valves*. (b) UGI's secondary valves were subject to design requirements in 49 *CFR* 192.181, "Distribution line valves." For more on the regulatory application of these requirements, see https://www.phmsa.dot.gov/regulations/title49/section/192747 and https://www.phmsa.dot.gov/regulations/title49/section/192181.

UGI emergency responders told the NTSB that they were not able to close the final valve at South 4th Avenue and Penn Avenue until about 6:15 p.m. because of dirt and debris inside the valve box. Once a vacuum truck arrived and removed the debris, the UGI emergency responders closed the valve, isolating the gas system in the area of the explosion about 1 hour after the responders first arrived on the scene.

## 1.4 R.M. Palmer Facilities and Heating System

At Palmer's West Reading facilities, candy operations involved molding, decorating, and foiling chocolate in four production areas located in Buildings 1 and 2.[24] Liquid chocolate was delivered at least daily by truck from an outside supplier and transferred by hose and piping into storage tanks in the basements of Buildings 1 and 2, which ranged in capacity from 4,000 to 7,700 gallons. The chocolate was kept liquid in the tanks by an ambient room temperature of 105–110°F, which was maintained by ceiling-mounted natural gas–fueled heaters. The liquid chocolate was then pumped from the tanks through the chocolate supply pipes to the various production areas within Buildings 1 and 2. Aside from the Building 2 basement heaters, other natural gas–fueled appliances at the accident location included a water heater in the Building 2 basement, a natural gas–fueled steam boiler located to the east of Building 1 for heating both buildings, and a gas-fueled generator outside Building 1 used as a backup energy source for the computer system.

Palmer's heating system was active at the time of the accident and had been for the previous several months. According to Palmer, steam flowed periodically from the boiler, which operated at 15 psig, based on heat demand in Building 2. The steam flowed to a regulator valve in Building 1 that dropped the pressure to 9 psig, and from there through a pipe underneath Cherry Street to Building 2.[25] Condensation from the steam heating system collected in a tank in the Building 2 basement and was pumped periodically back through the condensate pipe to the boiler.

In an interview with the NTSB, the truck driver who was making a delivery at the time of the accident stated he could recall the construction on the day of the 2021 UGI service tee replacement, because he had waited for the UGI crew to finish their work before completing his delivery. The truck driver stated that after that day, when

[24] *Foiling* involved adding foil wrappings to the molded candies.

[25] At 9 psig, the temperature of saturated steam is 237°F.

it was cold out, he would see steam rising from the section of asphalt covering the service tee replacement, and only that section.

## 1.5 UGI Corporation

UGI Corporation's subsidiary UGI Utilities Inc. serves about 688,000 natural gas customers and 63,000 electric customers in Pennsylvania and Maryland. UGI's annual throughput is about 314 billion cubic feet of natural gas and 1 billion kilowatt-hours of electricity. UGI's natural gas assets near the accident site are described in section 1.1.

### 1.5.1 Cherry Street Gas Main and Service Information

The Cherry Street Aldyl A gas main was installed in 1982. Service tees were used to branch off the main to provide gas service to Buildings 1 and 2. The tees were composed mostly of Aldyl A polyethylene components. Such tees had inserts and caps made of polyoxymethylene homopolymer, also known as polyacetal or Delrin.[26] The NTSB reviewed the specifications for Aldyl A service tees with Delrin inserts. The specifications indicate a maximum ground temperature of 100°F.

These tees were designed to perform three functions: (1) form a leak-free connection with the gas main, (2) form a leak-free connection to downstream service line piping, and (3) perforate the gas main to allow gas to enter the service line. The first function was accomplished by saddle fusing the tee to the gas main.[27] To complete the second function, service line piping and fittings were attached to the tee's outlet. Once a leak-free connection was established, the third function was accomplished using a cutter that was housed in the tower of the service tee. To complete this function, the cutter was lowered using a wrench until its tip cut a circular hole in the top of the gas main. The cutter was next raised to clear the cut hole and allow gas to enter the service line. The tee was then sealed by installing a threaded cap with rubber O-ring on top of the tee's tower. (See figure 7.)

[26] For more on the NTSB Materials Laboratory examination of the Building 2 service tee, see section 1.6.2.1.

[27] *Saddle fusing* joins a *saddle*—a fitting that holds a tee onto a pipe—to the pipe by heating the external surface of the pipe and the matching surface of the fitting.

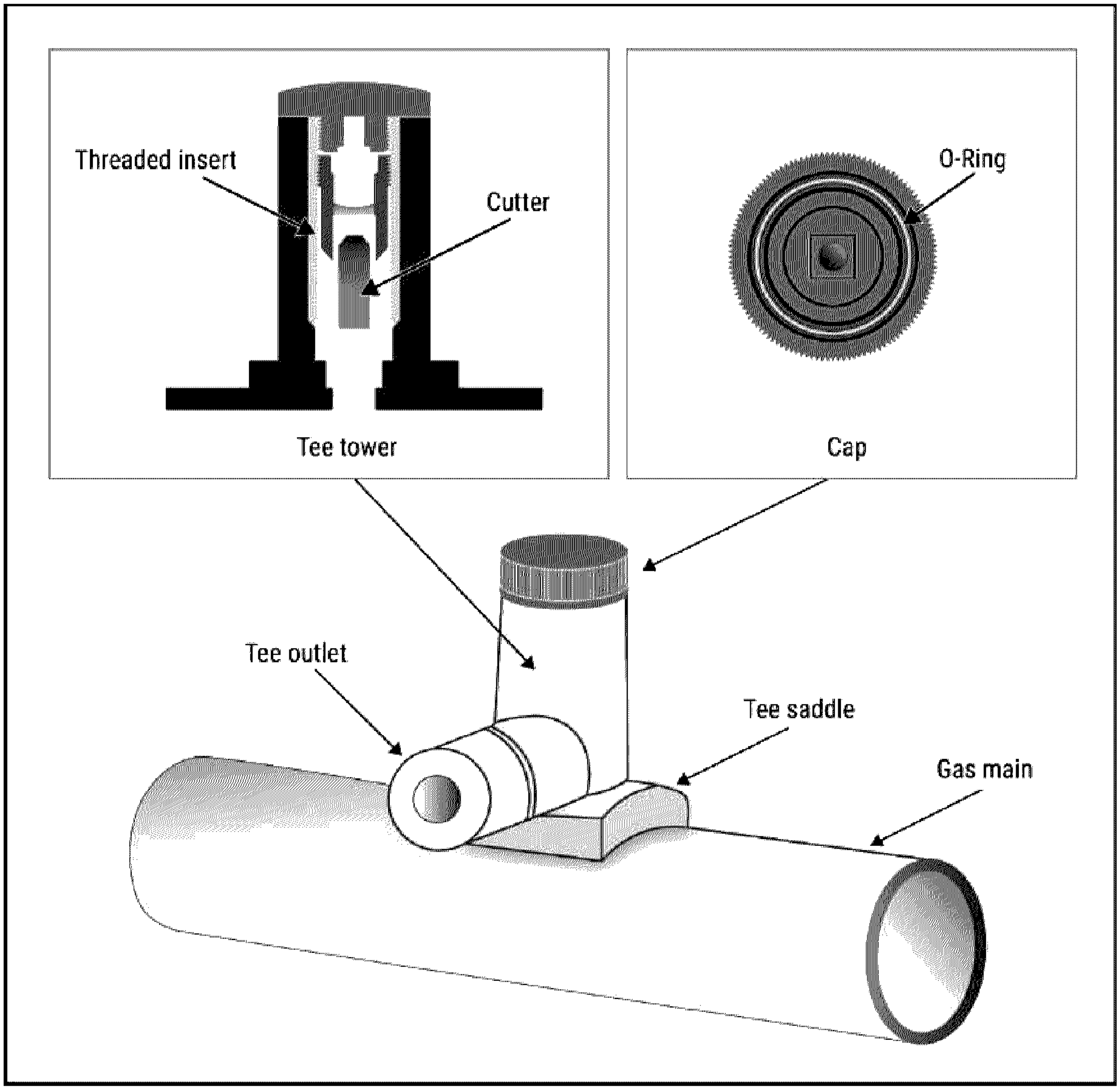


**Figure 7.** Aldyl A service tee and its components.

After the accident, the NTSB interviewed the crewmembers who had installed the new service tee and line to Building 2. None could recall the exact process of the 2021 service line and tee replacement, but they outlined the typical process. This included shutting off the gas flow at the old service tee by lowering the tee's internal tap to stop the flow of gas into the service line, cutting off the service line, and capping the remaining service line stub.[28] The internal tap in the service tee was then

[28] (a) This type of tee is also known as a tapping tee. (b) A *service line stub* is a short section of capped-off pipe that remains attached to a retired tee, as the tap itself is not designed to stop all the gas flow into the service line when it is lowered in the tee.

raised to reintroduce gas flow to the service line stub, and a soap test was conducted to verify the repair was leak free.[29]

### 1.5.2 UGI Leak Surveys Since 2011

UGI performed leak surveys (inspections to identify leaks) on (or over) the Cherry Street main in July 2011, July 2015, and June 2019, and on the service line to Building 2 in November 2014, August 2017, and August 2020.[30] No leaks were found during any of these surveys.

UGI also conducted three indoor leak surveys, two as part of its inside service line inspection program (Inside SLIP) and one when replacing some meters.[31] A 2018 Inside SLIP survey and a 2020 meter replacement found no leaks. The Inside SLIP survey on February 16, 2021, found a leak inside the Building 2 basement and just outside the building, and the meter was moved and the service line and tee replaced. (see section 1.1.2.)

### 1.5.3 Valve Inspections

UGI's GOM included procedures for valve maintenance and guidelines for maintaining and inspecting critical valves (also referred to in the industry as operating or emergency valves) and secondary valves. The procedures required that critical valves be inspected annually, that secondary valves be inspected at least once every 5 years, and that, during inspections, valves must be operated to determine whether they would work in an emergency. According to records from UGI and the Pennsylvania Public Utility Commission (PA PUC), the four valves that UGI personnel tried to close to isolate the system following the March 24, 2023, explosion were secondary valves and had been inspected on a regular, 5-year schedule as set by

[29] In a *soap test*, a soapy mixture is applied to piping surfaces to check for air or gas leaks. Bubbles will form at the site of a leak. Procedures for the retirement of service lines in the GOM include a soap test once the work is complete.

[30] Leak survey types and frequencies are specified in the GOM. Survey schedules vary based on pipeline materials and location. The regulatory schedule specified by 49 *CFR* 192.723 for leak surveys in business districts is once a year at intervals no longer than 15 months and outside business districts at least once every 5 calendar years at intervals no longer than 63 months. UGI did not consider the accident location to be a business district.

[31] Inside SLIP surveys were required by the GOM to be conducted every 3 years.

UGI.[32] UGI's reports of the most recent inspections of the four valves UGI attempted to operate in response to this accident are shown in table 2.

**Table 2.** Reported valve inspections.

| Valve Locaton | Date (Time Before the Accident) | Reported Result |
|---|---|---|
| **South 2nd Avenue/Penn Avenue** | March 23, 2021 (24 months) | Cleaned valve box or pit |
| **South 3rd Avenue/Penn Avenue** | April 16, 2020 (35 months) | Turned/key on |
| **South 4th Avenue/Penn Avenue** | March 2, 2022 (12 months) | Turned/key on, cleaned valve box or pit |
| **South 2nd Avenue/ Franklin Street** | March 2, 2022 (12 months) | Turned/key on |

The gas valve at South 2nd Avenue and Penn Avenue was not positively identified by UGI's mechanic during the emergency response; he was unable to verify the gas valve's identification number to confirm that it was the valve he intended to shut off. In July 2024, at the NTSB's request, UGI excavated the site and found the gas valve under a layer of asphalt near two water valves (water valves A and B).

A 2018 photograph provided by UGI of South 2nd Avenue and Penn Avenue is shown in figure 8 along with an inset image of the uncovered gas valve and water valve A from UGI's 2024 excavation. The gas valve is not visible in the 2018 image. A UGI representative stated that during the 2021 inspection, UGI personnel likely located a nearby water valve that had a gas cover (water valve A) and that they had likely inspected that valve.[33] He further stated that the appearance of and the mechanism used to operate the types of water and gas valves found at that location were nearly identical.

[32] Although PHMSA is primarily responsible for developing, issuing, and enforcing safety regulations for pipelines, states assume intrastate regulatory, inspection, and enforcement responsibilities under an annual certification with PHMSA. UGI is regulated by the PA PUC, which adopts the federal standards as their own. See *Pennsylvania Code*, Title 52, Chapter 59, "Gas Service."

[33] Valve identification numbers are typically located on plastic tags affixed to valve lids.

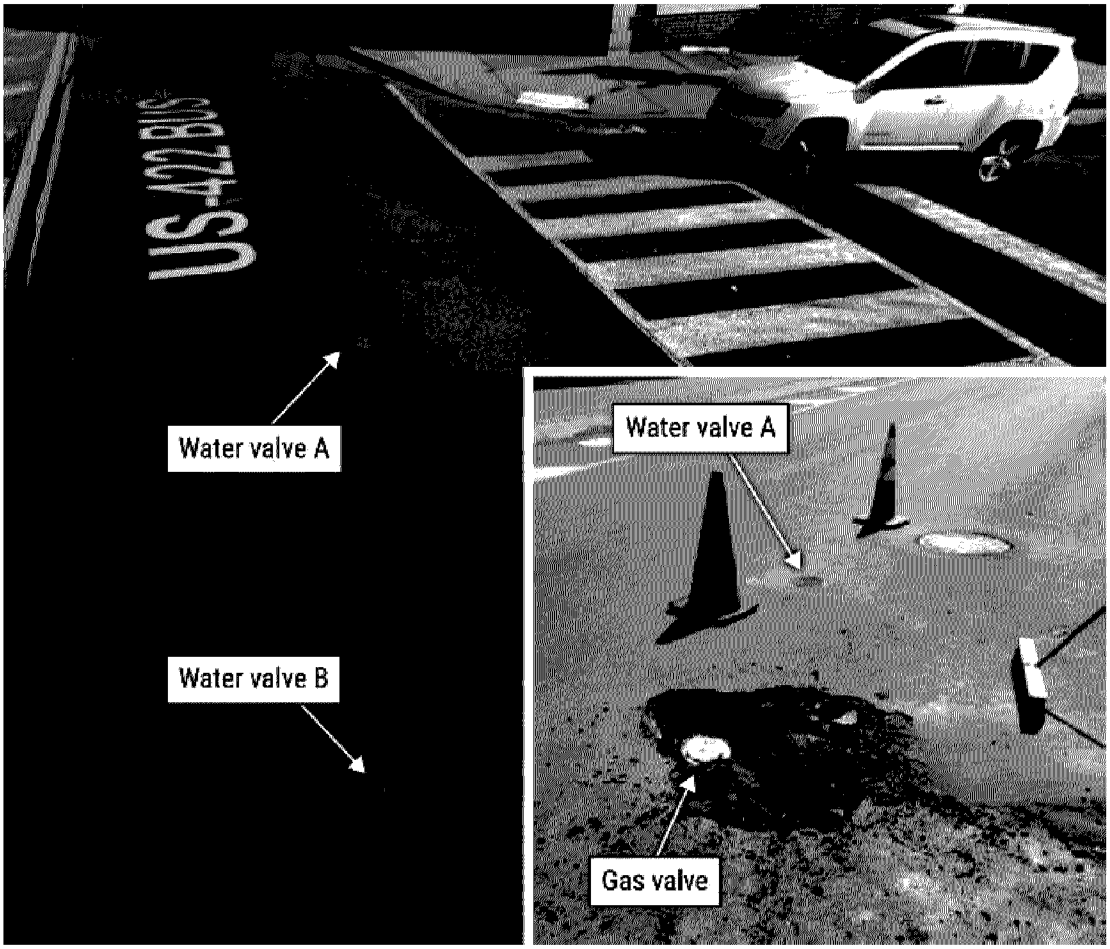


**Figure 8.** South 2nd Avenue and Penn Avenue intersection in 2018 (*main image*) and during an excavation in 2024 (*inset*); water valve A had a gas cover. (Source: Google Street view via UGI.)

The NTSB reviewed UGI's criteria for designating what it called critical valves. Under the criteria, UGI installs critical valves based on blocks containing a maximum of 1,000 customers that would be affected in an outage or emergency. The customer count does not distinguish between schools, businesses, or individual residences. Secondary valves are installed for operational convenience or to facilitate construction. If these valves are readily accessible, they may be used in an emergency.

## 1.6 Postaccident Examinations and Testing

After the accident, several responding organizations evaluated the site and the affected gas distribution system, and the NTSB launched an investigation on March 28, 2023. Between March 28 and April 27, the NTSB conducted a series of examinations and tests to determine the source of the natural gas that had fueled the explosion. The following section presents the results of responding organizations' evaluations before March 28 and of examinations and tests conducted or overseen by the NTSB after its investigation began.

### 1.6.1 On-Scene Examinations

#### 1.6.1.1 Explosion and Fire Origin Investigation

A federal, state, and local law enforcement team investigated the origin and cause of the Building 2 explosion and fire.[34] According to their report, the origin of the explosion and fire was the southwest quadrant of the Building 2 basement. The report describes three burn patterns, all in the southwest corner of the basement: one where the chocolate pipe conduits entered the basement; one to the right of the conduits, where a long-unused gas pipe (not pressurized with gas) entered the basement; and one around cracks and voids in the basement wall. The basement contained many pieces of mechanical and electrical equipment that could have provided an ignition source. The precise ignition source could not be determined, and the incident was classified as accidental.

#### 1.6.1.2 UGI Odorant Checks and Leak Survey

After the accident on March 24, UGI performed odorant checks and found that odorant was readily detectable.[35] UGI performed leak surveys and initial bar hole testing daily starting on March 24 along the closest gas mains serving the Palmer buildings that were accessible at the time, on the sidewalk along South 2nd Avenue between Franklin Street and Penn Avenue.[36] No gas was detected.

The day after the accident, on March 25, the PA PUC oversaw a UGI contractor performing a leak survey on Cherry Street adjacent to Building 2 using remote methane leak detector equipment. The leak source could not be identified by these tests. The PA PUC further oversaw gas quality sampling and bar hole testing that,

[34] The team included the Bureau of Alcohol, Tobacco, Firearms and Explosives; the Pennsylvania State Police; the West Reading Police Department; and the local fire marshal.

[35] UGI used odorant detection equipment to test the odorant concentration at five locations on the natural gas distribution system, including two near the Palmer buildings.

[36] *Bar hole testing* describes a gas measurement technique in which a small diameter hole is made in the ground, a bar hole probe is inserted into the hole, and a gas measurement is made. This technique identifies the extent of the natural gas in the ground in all directions from the depth of the pipeline upward.

along with similar testing from UGI, indicated the natural gas likely came from UGI's system rather than from a source of naturally occurring methane.[37]

#### 1.6.1.3 Gas Migration Study and Bar Hole Tests

On March 30, the NTSB directed and oversaw a gas migration study, beginning with 14 planned bar hole readings and extending to 43 readings in a 3-by-3-foot grid on South 2nd Avenue at the Cherry Street intersection.[38] Gas was detected adjacent to Building 2 at the intersection of Cherry and South 2nd Avenue. Readings ranged from 0% to 17% gas in air by volume. The flammable or explosive range of natural gas is between 5% and 15% gas in air by volume.

On April 22, 2023, when Building 1 had been stabilized and the area between Buildings 1 and 2 became safe for people to access, the NTSB conducted another gas migration study using bar hole testing on Cherry Street. The NTSB detected gas between the main and curb lines adjacent to Building 2. Readings ranged from 0% to 0.80% gas in air by volume. The results of the March and April bar hole tests are shown in figure 9.

[37] Echelon Applied Geochemistry, which conducted the testing for the PA PUC, analyzed gas geochemistry and soil gas concentration data. The NTSB was present during this test.

[38] A *gas migration study* is an analysis of bar hole testing results to assess the extent in all directions of natural gas migration in the ground.

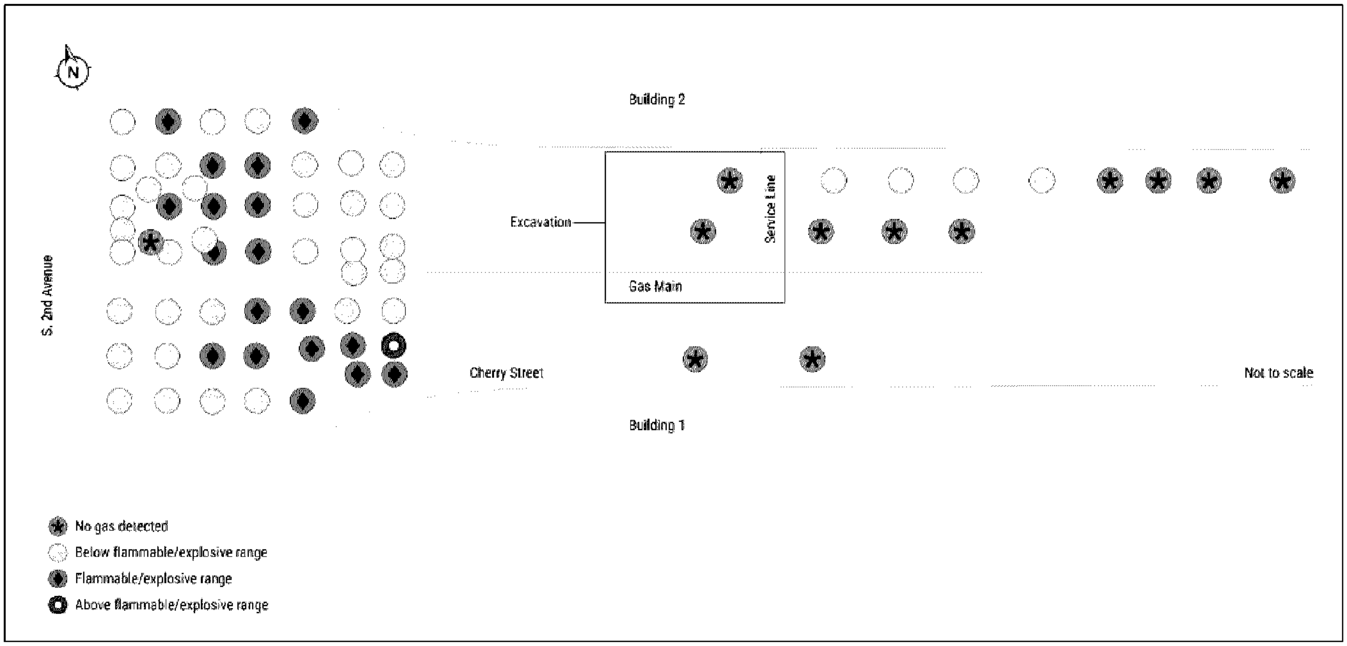


**Figure 9.** Bar hole test readings conducted in March 2023 (*left side of image*) and April 2023 (*right side of image*).

#### 1.6.1.4 Flow Rate Test and Airflow Observations

On April 23, the NTSB directed and oversaw a flow rate test, in which UGI personnel pressurized the Cherry Street main with compressed air to quantify the leak rate of the gas that had been detected near Building 2 during the March and April gas migration studies.[39] Flow test results indicated that a leak rate of about 115 cubic feet per minute (natural gas equivalent) was present in the Cherry Street main when it was pressurized to about 39 psig.[40]

During the flow rate test, investigators went to the Building 1 basement and viewed the two underground chocolate pipe conduits that connected Buildings 1 and 2 to find possible pathways for gas migration. This was the same area where firefighters observed a fire during their initial response to the accident (see section 1.3.2). The NTSB observed air flow entering the basement through the conduits. When the flow rate test was terminated, investigators no longer detected air flow through the conduits.

#### 1.6.1.5 Pressure Tests

UGI crews evaluated the integrity of the natural gas assets near the accident site as they became safe to access. First, a pressure test was conducted on the South 2nd Avenue main on March 29. The tested section held pressure for the length of the test, 1.5 hours. Next, on April 2, an accessible portion of the Cherry Street main was also pressure tested and held pressure for 1.5 hours.[41] The service line to the boiler house behind Building 1 was tested and held pressure for 1.5 hours.

On April 22, after the bar hole testing confirmed natural gas concentrations in the ground, the NTSB oversaw an initial pressure test of the portion of Cherry Street main between Buildings 1 and 2. The gas main failed to hold pressure. NTSB investigators smelled gas near the service riser to Building 2 and from an excavated area on South 2nd Avenue.[42] When the service line to Building 2 was pressure tested

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[39] A *flow rate test* measures the volumetric flow of gas over a time interval at a specific temperature and pressure.

[40] The maximum allowable operating pressure of the Cherry Street main was 60 psig.

[41] The tested section was approximately 20 feet in length and located at the intersection of Cherry Street and South 2nd Avenue. This portion of the Cherry Street main encompassed the transition from 2-inch steel to 1.25-inch Aldyl A.

[42] A *riser* is a pipe that connects underground piping to aboveground piping and assets, such as the gas meter.

on April 26, it lost about 5 psig in 5 minutes of testing, indicating a relatively large leak. Further pressure testing confirmed the presence of a leak in the segment that contained the active and retired service tees to Building 2. Pressure testing also revealed a small leak in the service line to Building 2. The pipeline and its riser were sent to the NTSB Materials Laboratory for further testing. (See section 1.6.2.3.)

#### 1.6.1.6 Air Flow Velocity and Smoke Tests

On April 24, a representative from the Occupational Safety and Health Administration (OSHA) conducted air flow velocity measurements to determine the rate of air flow between Buildings 1 and 2 in their postaccident conditions. The representative took the measurements from the Building 1 basement at the opening of the two underground chocolate pipe conduits. The average baseline air flow velocity around the pipe conduits was 2 feet per minute. When the Cherry Street gas main was pressurized with air to 26 psig, air flow velocity measurements at the conduits increased from baseline, ranging 8.8 to 21 feet per minute.

The Pennsylvania State Police deputy fire marshal connected a smoke generator to the chocolate pipe conduits in the basement of Building 2 and started it up to investigate whether gas could flow between the two buildings. Smoke was observed in the basement and on the third floor of Building 1.

To further test the interaction between the chocolate pipe conduits and the ground around the gas pipelines, the NTSB used rags to block the spaces in the conduit opening around the chocolate pipes in the Building 1 basement. When the smoke generator was restarted in the Building 2 basement, smoke emanated from the ground near the Building 2 foundation and the gas service line. (See figure 10.)

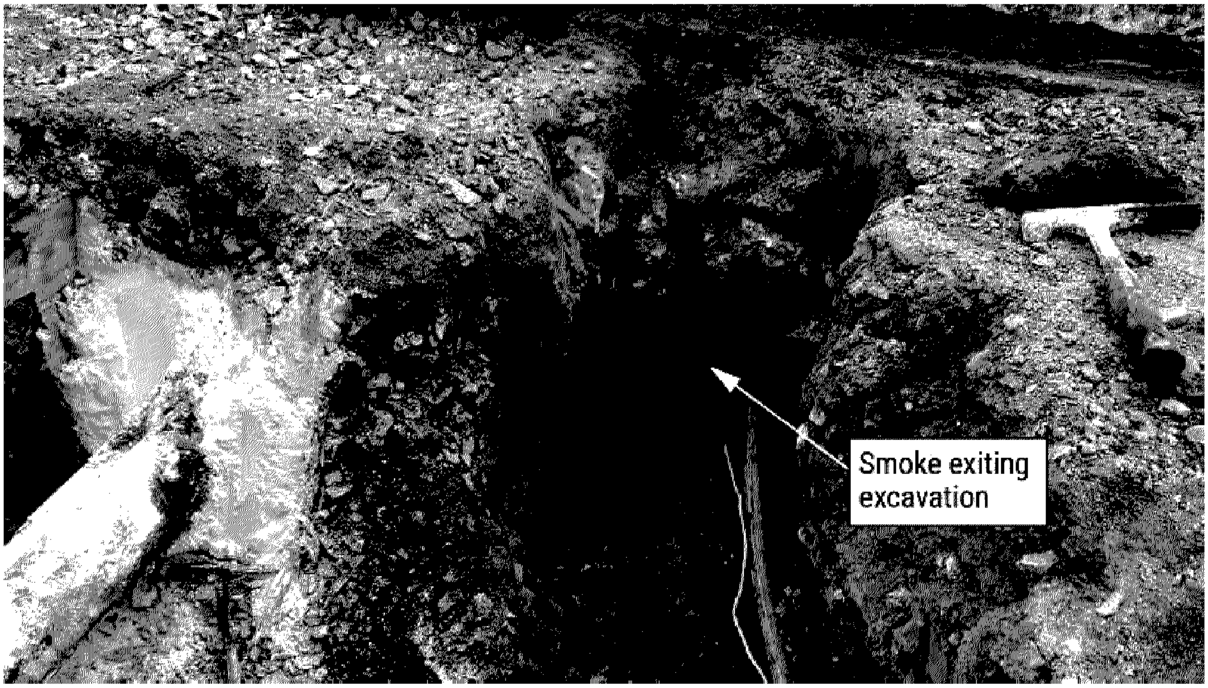


**Figure 10.** Smoke from conduit visible near gas service line to Building 2.

### 1.6.1.7 Excavation

On April 26, the excavation of Cherry Street just south of Building 2 exposed the natural gas pipelines and other components, along with Palmer's chocolate conduits, steam pipe, and condensate line, shown in figure 11.

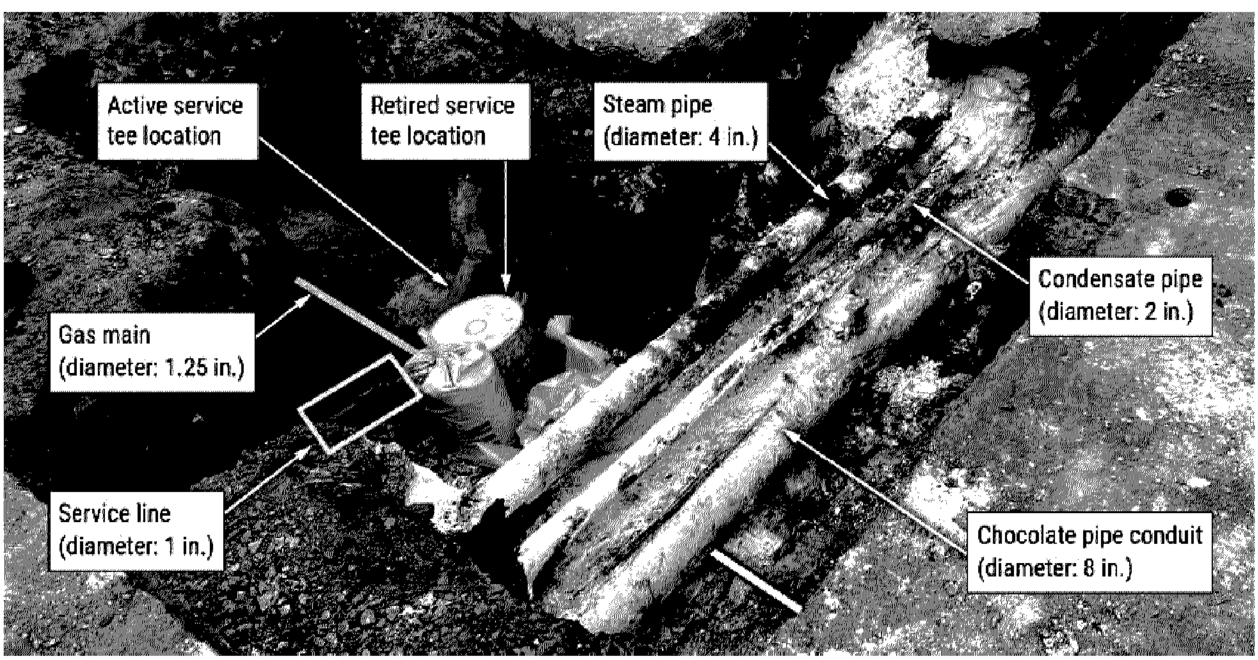


**Figure 11.** Excavation of pipes at the accident location.

As the retired service line to Building 2, which was under pressure, was being unearthed, the NTSB observed that air was coming from the top of the retired 1982 service tee. The service tee's cap and a portion of its insert were missing.[43] The NTSB oversaw as UGI sifted the soil from the excavation but did not recover the cap or the upper portion of the insert; the lower portion of the insert remained with the service tee. The NTSB removed the remaining portions of the retired service tee, along with the section of 1.25-inch-diameter Aldyl A gas main to which the tee had been attached, and sent them to the NTSB Materials Laboratory for evaluation (see section 1.6.2).

The NTSB also removed a marker ball, which UGI had placed next to the Building 2 service tees as part of the 2021 replacement project, and retained it for examination at the NTSB Materials Laboratory.[44]

#### 1.6.1.8 Visual Inspections

Also on April 26, the Pennsylvania State Police deputy fire marshal visually inspected what remained of the Building 2 basement. Investigators in the basement of Building 1 pointed a flashlight through the chocolate pipe conduits toward the Building 2 basement to see whether air flow through the conduits could have been obstructed by insulation or other material. The deputy fire marshal observed light through the conduits. (See figure 12.)

[43] The UGI field crew would have reinstalled the cap of the retired service tee to seal it upon installation of the new Building 2 tee in 2021.

[44] A *marker ball* is a hollow sealed sphere, made from a thermoplastic polymer and partially filled with a leveling fluid, that is used to identify plastic underground utilities.


**Figure 12.** A view of one of the chocolate pipe conduits from the Building 2 basement.

Investigators also observed corrosion and a through-wall crack of approximately 4 inches on the underground steam pipe that had been exposed in the NTSB's postaccident excavation. This pipe was located about 15.5 inches above and 23 inches to the west of the retired service tee.[45] Visual observation of the length of the exposed pipe showed external corrosion, which can also be seen in figure 11. The NTSB oversaw as UGI removed surface rust from the steam pipe (outside of the section containing the through-wall crack) to take wall thickness measurements. The thickest measurement was 0.216 inches and the thinnest was 0.148 inches. The

[45] The pipe was between 25 and 30 feet from the Building 1 service tee.

cracked section of the steam pipe was sent to the NTSB Materials Laboratory for examination (see section 1.6.2.5).[46]

### 1.6.2 Laboratory Examinations and Research

From June 26 to June 30, 2023, the NTSB examined the natural gas piping, tees, steam pipe, and related pipeline components retained from the accident scene. Detailed descriptions of these examinations are below.

#### 1.6.2.1 Aldyl A Retired Service Tee

The NTSB examined the retired service tee's tower, which is the cylindrical barrel on the top of the tee that houses the cutter. The tower was a two-piece assembly consisting of a cylindrical Delrin insert surrounded by an Aldyl A outer shell. The inner surface of the insert was threaded to guide the internal cutter and to secure the service tee cap, and the outer surface contained longitudinal and circumferential ribs. The Aldyl A shell was molded and formed around the insert, with corresponding grooves that interlocked with the ribs on the insert to resist axial and rotational movements during cutting and capping.

A visual examination of the retired service tee revealed a 1.9-inch fracture through its polyethylene tower shell, from the top of the tower nearly to its base. (See figures 13 and 14.) The fracture was centered in one of the longitudinal grooves located on the inner surface of the shell and had initiated at a line-like impression in the groove consistent with a mold parting line.[47]

[46] The NTSB observed a subsurface white powder surrounding the Palmer steam pipe and other assets that had been exposed. A third-party laboratory examination determined that the powder was predominantly calcium carbonate. The NTSB investigation did not determine the source or purpose of the powder.

[47] A *mold parting line* is a line left by two halves of a mold.

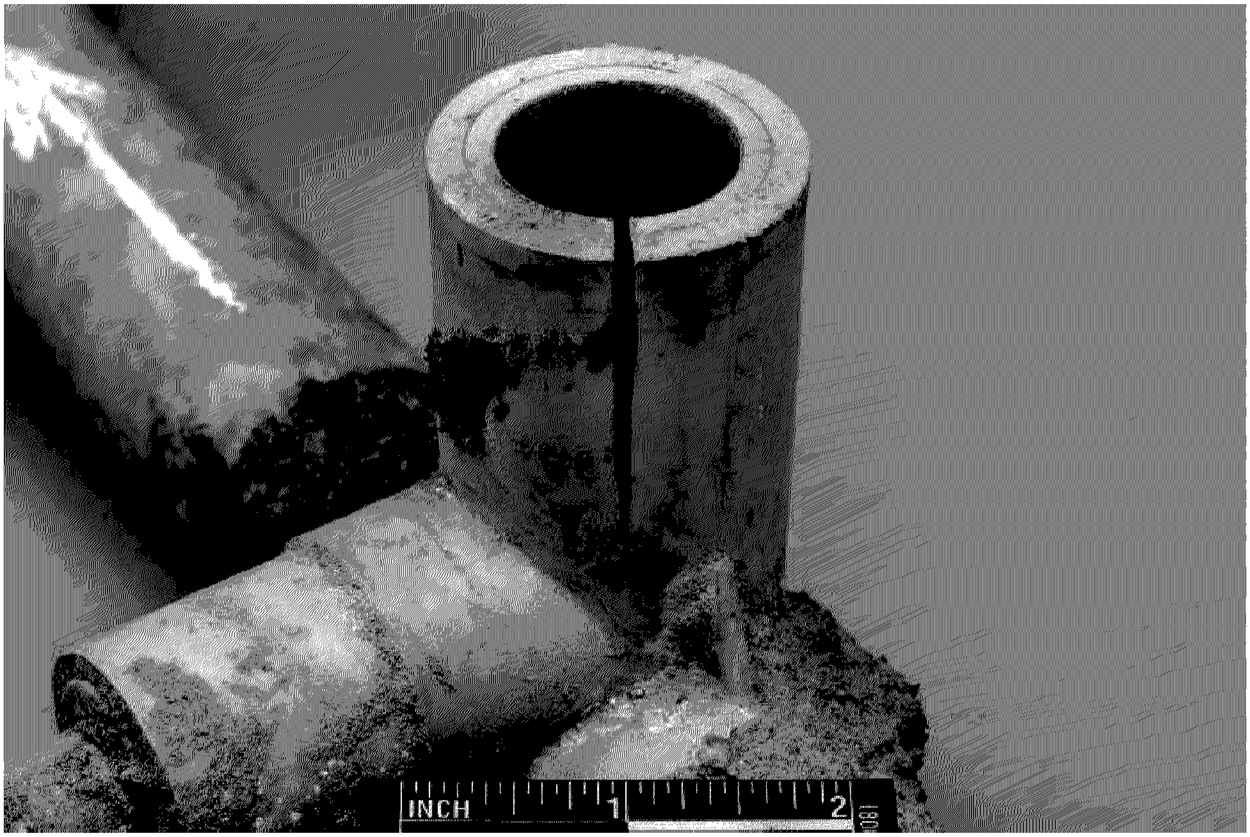


**Figure 13.** Longitudinal fracture in retired service tee.

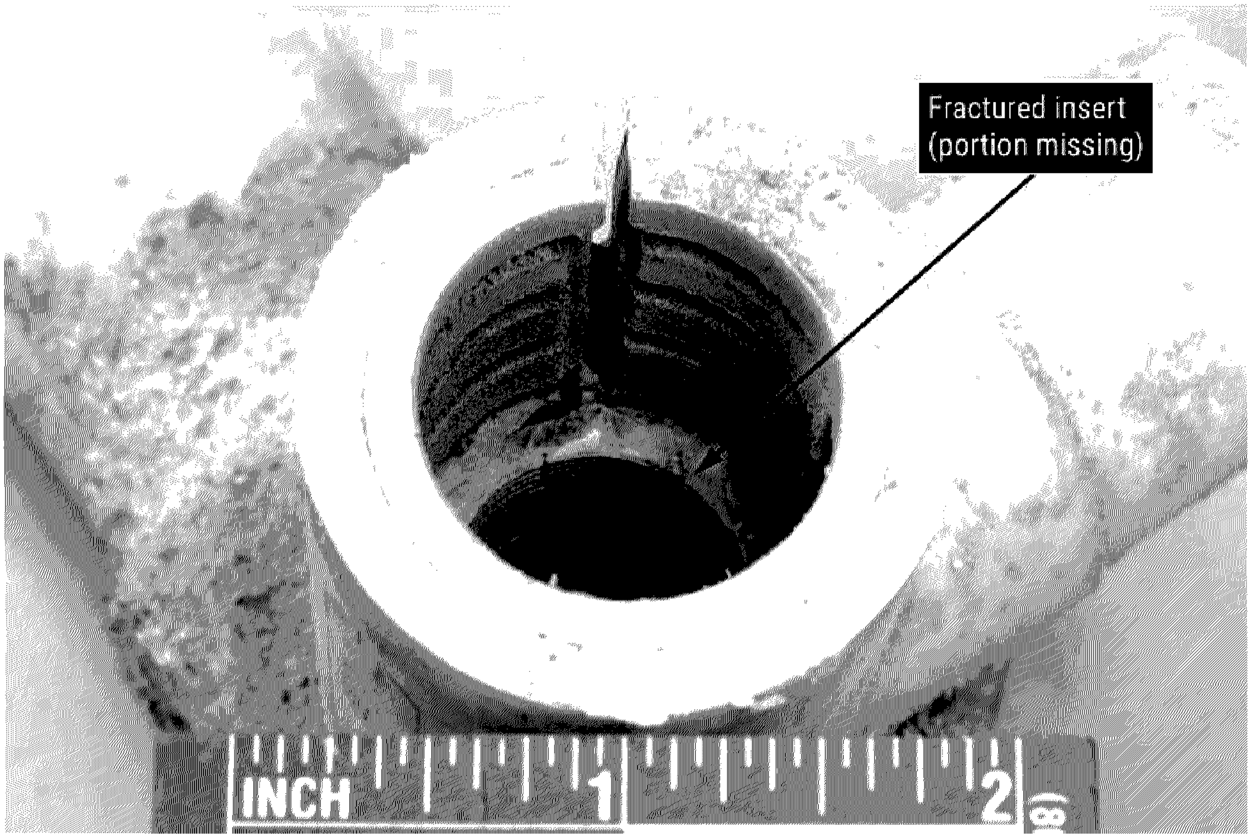


**Figure 14.** Interior of retired service tee tower with top portion of Delrin insert missing.

One of the fracture surfaces was cleaned and examined. It exhibited features consistent with fracture initiation from slow crack growth.[48] The slow crack growth region originated on the interior surface of the shell, between 0.325 inches and 0.430 inches from the top of the tower. From there it progressed through the wall, to the top of the tower and toward its base. Toward the top of the tower, the fracture surfaces were flat, comparatively featureless, and exhibited fibrils.[49] Near the base, the flat, featureless regions of the fracture surface transitioned to hackle consistent with a fast fracture following slow crack growth.[50] (See figure 15.)

[48] *Slow crack growth* is a time- and temperature-dependent type of polymer failure occurring under low stress levels.

[49] *Fibrils* are filaments of polymeric material that form bridges between opposing crack faces.

[50] *Hackle* refers to line-like features on a fracture surface that run in the local direction of cracking.

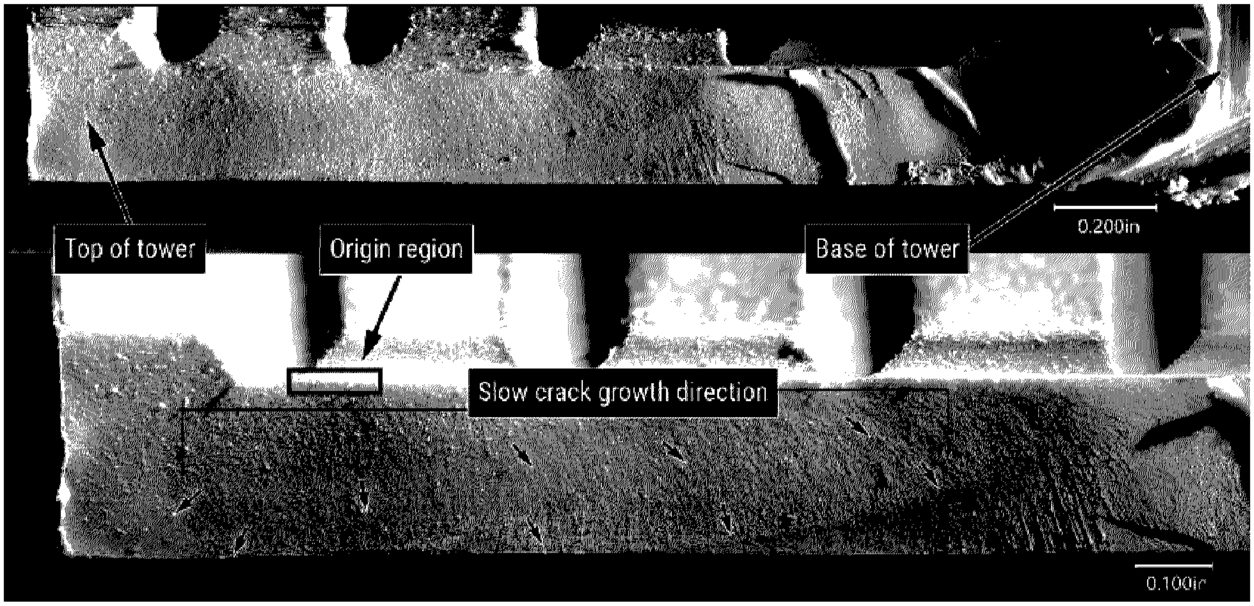


**Figure 15.** (*Top image*) Longitudinal fracture from top to base of tower. (*Lower image*) Detailed image of slow crack growth region.

A visual assessment of the retired service tee's Delrin insert showed that it too was fractured, with a transverse fracture located near the bottom of the insert. A region of the fracture, which was closest to the steam pipe before the accident, had a crazed and fibrous appearance.[51] Elsewhere, the fracture had a granular and porous appearance. The outer surface of the insert showed surface cracking and volume loss, which is visible in figure 16 along with the fracture origin. This was the first accident NTSB has investigated involving a longitudinal fracture from thermal degradation of an Aldyl A service tee with Delrin insert.

[51] *Crazing* is a network of fine cracks that often precede fracture in some polymers.

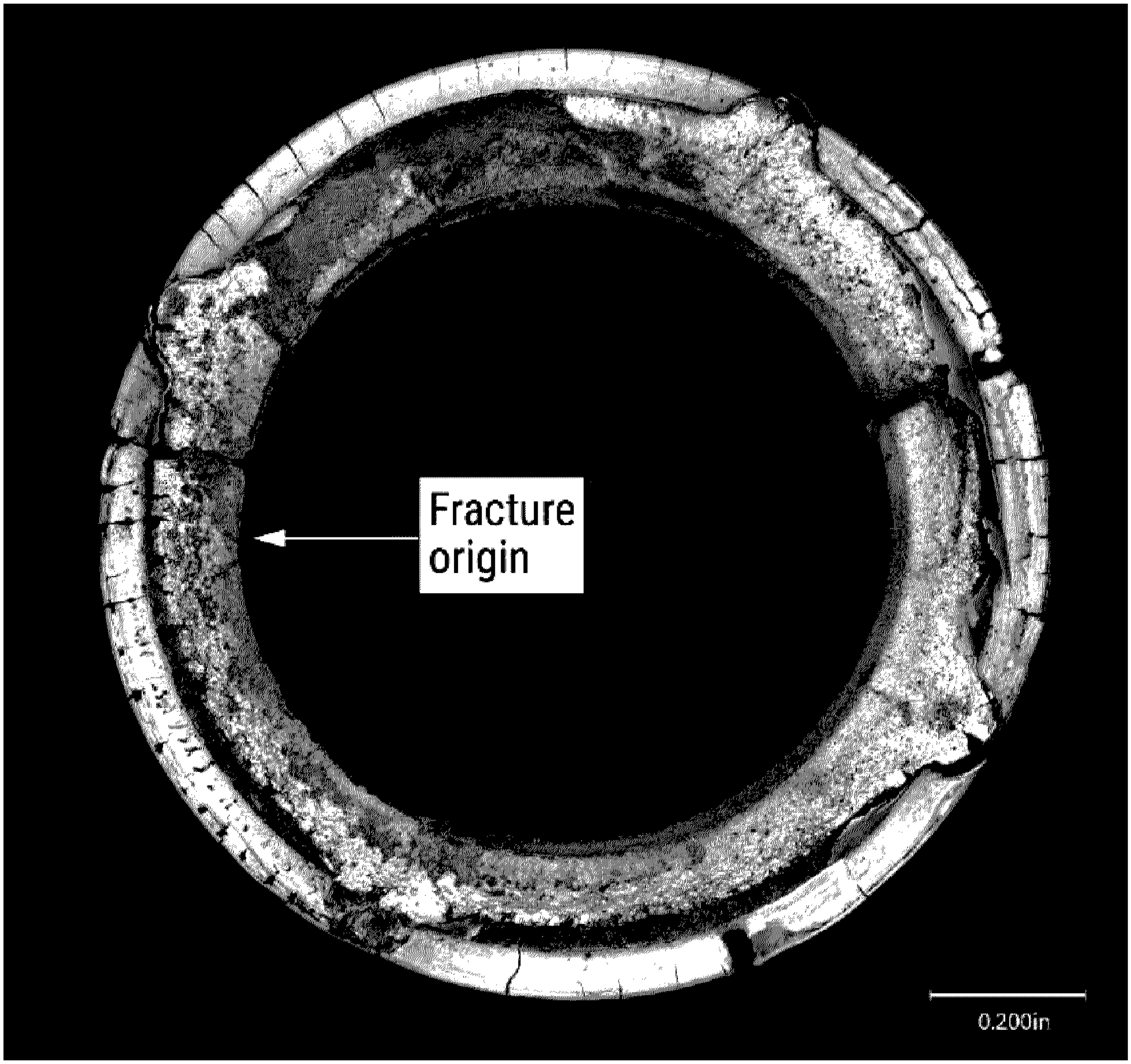


**Figure 16.** Image of fracture surface on Delrin insert for retired service tee.

#### 1.6.2.2 Aldyl A Gas Main

X-ray CT scans revealed a small crack in the 1.25-inch Aldyl A Cherry Street main, located underneath the Building 2 active service tee saddle, where bubbles had appeared in an earlier leak test.[52] The NTSB observed that the crack was visible on the inner pipe surface, measured 0.39 inches in length, and was centered just upstream of the tee outlet. Examination of the fracture surface indicated that the

[52] (a) The saddle of the active service tee had been fused to the main but also clamped to it by an undersaddle. (b) This leak test measured a flow rate of 0.6 standard cubic feet per hour.

crack had initiated on the outer surface of the pipe and that it exhibited progressive start–stop and slow crack growth features.

#### 1.6.2.3 Polyethylene Service Line

The NTSB examined the active Building 2 polyethylene service line, in which pressure testing had revealed a small leak, and the service line's flexible steel and rubber riser. They observed a cut where the wall of the service line had impinged upon a sharp, deformed edge on the flexible riser's downstream fitting. Stretching and deformation of the flexible riser led to the formation of the sharp edge. These mechanical damage features were consistent with explosion damage.

#### 1.6.2.4 Building 1 Service Tee

The NTSB examined the service tee to Building 1, which like the Building 2 service tee had been installed in 1982 and was composed of Aldyl A material with a Delrin insert. The tower shell, insert, and cap did not show cracking or material decomposition.

#### 1.6.2.5 Steam Pipe

The NTSB examined a 46-inch segment of the steam pipe that had been recovered from the accident site. The pipe was made of steel and was 4 inches in diameter, with a wall thickness of between 0.20 and 0.22 inches.[53] The sample of pipe examined by the NTSB displayed varying levels of wall thickness loss. The steam pipe had been deformed by shear forces (acting on opposite sides of the pipe) near the middle of the segment, with the direction of shear downward.

Within the sheared region, the pipe was corroded on its outer surface and cracked. Within the examined section, the smallest wall thickness measurement, 0.038 inches, occurred near the edge of one of the cracks.[54] The cracks were located on the east-facing side of the pipe, facing the Building 2 retired tee, and were inclined relative to the longitudinal axis of the pipe. The longest crack was about 4

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[53] These measurements are consistent with 3.5-inch schedule 40 pipe (nominal pipe size).

[54] This thickness was 17% of the pipe's initial (nominal) wall thickness.

inches long and had formed along a compressive buckle within the sheared region.[55] Two shorter cracks branched off the 4-inch crack. (See figure 17.)

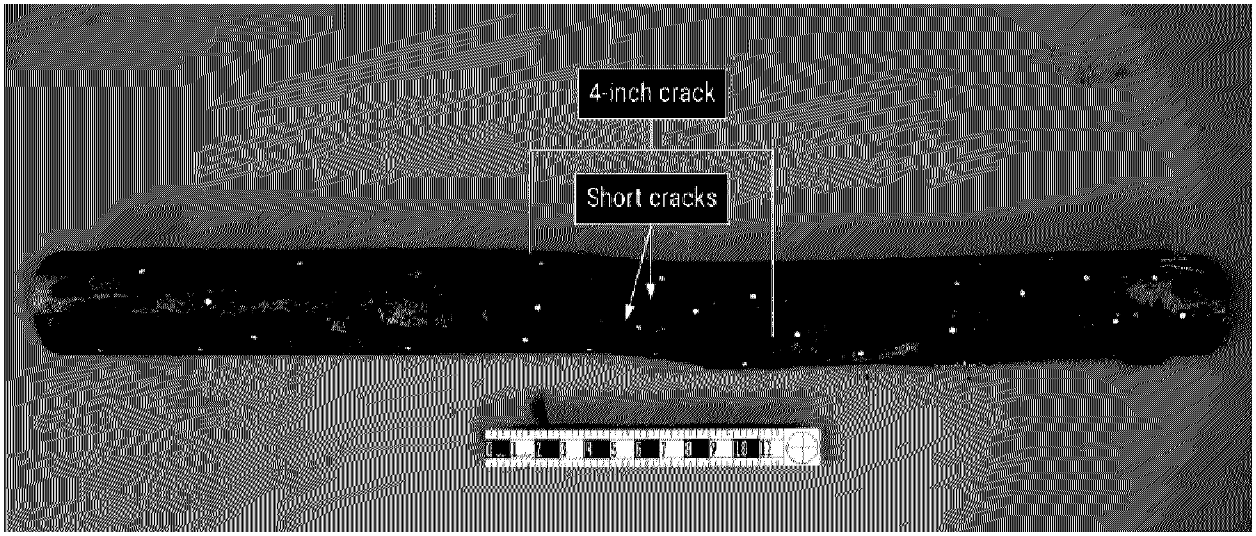


**Figure 17.** Through-wall cracks in steam pipe.

#### 1.6.2.6 Marker Ball

The plastic marker ball retained from the accident site was observed to have collapsed inward from both the top and the bottom. The seam that had sealed the two halves of the marker ball had also separated, allowing much of the liquid contents of the ball to escape.

#### 1.6.2.7 Simulation

The NTSB Materials Laboratory conducted a finite element simulation to study the effect on the surrounding environment of an intact steam pipe—one with no crack—operating at 10 psig, with modeled ground temperatures of 40°F and 60°F from regional historical data. For the range of ground temperature and soil properties studied and for the likeliest condition of steam flowing unassisted through the pipe, the temperature at the location of the retired service tee was 27°F to 40°F above the ground temperature.

#### 1.6.2.8 Photographic Study

As UGI worked on the service line replacement project on Cherry Street on February 16, 2021, a Palmer employee took a photograph of the work.

[55] This sort of *buckling* or outward deflection occurs when a material is subjected to compressive stresses beyond a certain level.

(See figure 18.) The NTSB reviewed the photograph to estimate the extent and location of excavation with mechanized equipment, and the photographic study showed that the excavation took place around the same location as the crack in the steam pipe. (See section 1.6.2.5.) The study showed that the west edge of the excavation was located within about 1 foot of the location of the steam pipe and that the excavation extended south of the location of the crack. The study was unable to determine the depth of the excavation.

**Figure 18.** UGI crew during service line replacement project, 2021. (Photo courtesy Palmer.)

## 1.7 Regulations, Advisories, and Standards

### 1.7.1 Pipeline and Hazardous Materials Safety Administration

Federal pipeline safety regulations are found in Title 49 *Code of Federal Regulations* (*CFR*) Parts 190 through 199, with 49 *CFR* Part 192 covering the minimum federal safety standards for transportation of natural and other gas. For the gas distribution system involved in this accident, Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations apply to main and service lines up to the outlet of the gas meter. PHMSA regulations include requirements for the gas distribution operator to manage the integrity of its system, maintain its valves, and conduct public awareness programs. The agency also issues advisory bulletins to provide guidance and awareness to the industry on specific safety concerns.

Federal regulations specify location, accessibility, and maintenance requirements for distribution line valves. Natural gas pipeline operators must determine which of their valves are necessary for operating or emergency purposes. PHMSA specifies that the valves used for operating or emergency purposes must be placed in a "readily accessible location," and those that are necessary for the safe operation of a distribution system must be maintained annually, with time between inspections not to exceed 15 months.[56]

Federal regulations require natural gas pipeline operators to maintain a public awareness program that meets criteria in the first edition of the American Petroleum Institute's (API) Recommended Practice (RP) 1162, which offers guidance on public awareness program development, stakeholder audiences, message content, delivery methods, documentation, record keeping, and program evaluation.[57] The first edition of API RP 1162, released in 2003, is incorporated by reference into the federal regulations; the standard is now in its third edition. The four stakeholder audiences outlined in RP 1162 are (1) the affected public, (2) local and state emergency response and planning agencies, (3) local public officials and governing councils, and (4) excavators.[58] According to RP 1162, a public awareness program must

[56] See 49 *CFR* 192.181, "Distribution line valves," and 49 *CFR* 192.747, "Valve maintenance: distribution systems."

[57] See 49 *CFR* 192.616, "Public awareness."

[58] The affected public defined by the first edition of API RP 1162 includes residents of both single- and multifamily structures as well as "places of congregation," or places where people assemble or work on a regular basis.

communicate to the affected public that they live or work near a pipeline, how to recognize and respond to a pipeline emergency, and protective actions in the event of a natural gas leak. Bill stuffers, or inserts included in monthly gas bills, are specified as a baseline (that is, must be conducted at minimum) public awareness activity in RP 1162 with a baseline frequency of twice annually.[59] Targeted distribution of print materials is specified as a supplemental activity. For the emergency officials stakeholder group, the standard specifies once-yearly print materials or group meetings as a baseline public awareness activity.

In November 2002, PHMSA issued an advisory bulletin notifying pipeline operators of the susceptibility of older plastic pipe, like Aldyl A, to premature brittle-like cracking.[60] In the bulletin, PHMSA stated that "piping installed in areas with higher ground temperatures or operated under higher operating pressures will have a shorter life" (PHMSA 2002). An updated advisory bulletin was issued on August 28, 2007, and added Delrin-insert tapping service tees to the list of pipe materials that are susceptible to brittle-like cracking (PHMSA 2007).

### 1.7.2 Pennsylvania Public Utility Commission

The PA PUC enforces 49 *CFR* Part 192 regulations for all gas distribution operators in the state and imposes additional requirements through state code. The PA PUC has inspected UGI for safety compliance with the Pipeline and Hazardous Materials Safety Administration's minimum federal safety standards.

The PA PUC reports for UGI's distribution integrity management program (DIMP) showed that for the years 2018, 2020, 2021, and 2022, the PA PUC found no compliance concerns with UGI's program.[61] The 2019 inspection found that UGI's DIMP did not comply with federal and state DIMP requirements to identify threats, evaluate and rank risks, and identify and implement measures to address risks.

[59] Natural gas distribution companies frequently mail *bill stuffers*, or printed brochures, along with customer gas bills.

[60] *Brittle-like cracking* initiates in the pipe wall but does not immediately result in a full break; it leads to stable crack growth at relatively low stress levels and often correlates with slow crack growth.

[61] A DIMP is a performance-based program resulting from the Pipeline Inspection, Enforcement and Protection Act of 2006, which requires pipeline operators such as UGI to collect and manage data on pipeline integrity.

### 1.7.3 Occupational Safety and Health Administration

Federal OSHA regulations are found in 29 *CFR* Chapter XVII and apply to most private-sector employers and workers in all 50 states (including Palmer in Pennsylvania), the District of Columbia, and other US jurisdictions. OSHA's authority generally applies to private-sector employers, but it allows states to assume responsibility for occupational safety and health for the private sector as well as for state and local employers and workers under an OSHA-approved state plan. Pennsylvania is a federal OSHA state, meaning it does not have an OSHA-approved state plan.

OSHA requires that employers have an emergency action plan that includes procedures for employees to follow during workplace emergencies.[62] The plan must include escape procedures and routes and accountability of employees after an emergency evacuation. Title 29 *CFR* 1910.38, "Emergency action plans," only applies when referenced in another OSHA standard.[63] Two OSHA standards referencing 29 *CFR* 1910.38 applied to Palmer at the time of the accident: one standard states that companies must maintain an employee alarm system, and the other states that companies must have fire extinguishers.[64]

### 1.7.4 Codes

The Commonwealth of Pennsylvania requires that all its boroughs follow the Pennsylvania Uniform Construction Code for all buildings and structures within a borough. At the time of the accident, West Reading had adopted the Pennsylvania Uniform Construction Code and the 2015 edition of the International Fire Code (IFC), and Pennsylvania had adopted the 2018 edition of the International Building Code, which applies to the safe construction of buildings or structures and references parts

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[62] See 29 *CFR* 1910.38, "Emergency action plan."

[63] Title 29 *CFR* 1910.38(a) states the following: "Application. An employer must have an emergency action plan whenever an OSHA standard in this part requires one."

[64] See 29 *CFR* 1910.157, "Portable fire extinguishers," and 29 *CFR* 1910.164, "Fire detection systems." OSHA defines an employee alarm system as "any piece of equipment and/or device designed to inform employees that an emergency exists or to signal the presence of a hazard requiring urgent attention." See OSHA's Evacuation Plans and Procedures eTool.

of the 2018 editions of the IFC and the International Fuel Gas Code (IFGC).[65] The International Code Council (ICC) administers the IFGC and IFC.[66] The IFC requires a fire safety and evacuation plan, but not a natural gas emergency procedure. IFGC addresses the design and installation of gas-fueled appliances and fuel gas systems past the outlet of the gas meter, which are not covered by federal or state transportation safety standards. Like the IFGC, the National Fuel Gas Code, referred to as National Fire Protection Association (NFPA) 54, provides minimum safety requirements for the design and installation of fuel gas piping systems and is administered by the NFPA, a nonprofit organization that issues widely adopted consensus codes and standards designed to minimize the risk and effects of fire. NFPA committees are responsible for revision of the codes and standards through an American National Standards Institute–accredited process. NFPA 54's Annex D, which is included only for informational purposes and does not contain requirements, lists immediate actions to be taken when natural gas is detected inside a building, including clearing the area of all occupants, eliminating ignition sources, shutting off gas supply, and calling 9-1-1.[67] NFPA also has a fire code, NFPA 1, which contains a fire safety and evacuation plan but not one specific to natural gas.

[65] (a) *Building codes* are a set of requirements for building design, construction, operations, and maintenance that are officially adopted and may be enforced by a jurisdiction. Palmer's West Reading facilities were built before the development of the borough's codes department. In general, buildings built to the codes of their time can remain in their original state even as codes are updated. (b) The IFC is primarily a maintenance code addressing fire safety within a building.

[66] The ICC is accredited under the American National Standards Institute and develops these codes through technical committees.

[67] Pennsylvania has adopted NFPA 54 only for industrial and commercial use of propane and other liquid petroleum gases. The standard did not apply to Palmer, because the company did not use these chemicals in Buildings 1 and 2. For more, see *Pennsylvania Code* Title 34, Chapter 13.4, "Adoption of National Standards."

## 1.8 Plans, Procedures, and Programs

## 1.8.1 R.M. Palmer

### 1.8.1.1 Emergency Response Procedures

Palmer's emergency plan manual, which the company referred to as the Red Book, addressed food and employee safety for all Palmer facilities.[68] The Red Book included an emergency contact list with phone numbers for federal, state, and local law enforcement; the National Response Center; and utility companies such as UGI, Palmer's contact for natural gas emergencies. The Red Book also contained maps indicating emergency shut-off locations for all utilities within Palmer's facilities, including the gas shut-off in Building 2, which was located on the inside wall of the basement facing Cherry Street. The Red Book did not include a procedure for when to call UGI or when or how to shut off gas. Palmer maintenance employees interviewed by the NTSB stated they had not been trained in gas leak detection.

The company's crisis management plan, part of the Red Book, listed various potential threats to business operations, such as fire, power failure, storm damage, flood, civil unrest, and equipment failure. A natural gas emergency was not listed among the threats in the crisis plan, and the Red Book did not contain procedures specifically addressing natural gas emergencies. Procedures were included for facility evacuation in general emergency situations. Evacuation was prompted by alarms triggered by activation of sprinklers, manual pull stations, or smoke and heat detectors. The Red Book directed employees to "stop all activities and proceed to the nearest exit and then to their designated muster point[s]" and specified that evacuation drills should be held "periodically." The Red Book listed muster points and evacuation route maps for Buildings 1 through 4.

In interviews with the NTSB, the Palmer chief executive officer (CEO) and vice president of operations and technical services (VP) considered a natural gas leak a low risk at the accident location, stating that the buildings' natural gas use was relatively minimal and that if a leak were to occur, employees would have "time to react to things."

[68] Palmer developed the employee safety guidelines in the Red Book in 2005, using guidance from OSHA, the National Institute for Occupational Safety and Health, the US Environmental Protection Agency, the Pennsylvania Department of Environmental Protection, the NFPA, and Industrial Risk Insurers. At the time of the accident, the Red Book had been most recently revised in August 2022.

#### 1.8.1.2 Safety Training

According to interviews with Palmer employees, their employee safety training mostly pertained to performing job tasks. Palmer did provide some employees additional training on safety equipment like fire extinguishers. Most employees interviewed by the NTSB recalled familiarity with the evacuation procedure in the Red Book and reported that the company conducted annual fire drills. The NTSB's review of Palmer records related to fire and emergency evacuation drills showed that evacuation times varied, with 5 minutes from the pull of the fire alarm as the shortest evacuation time.

The Palmer employees interviewed by the NTSB stated that they were never trained on how to respond to a natural gas emergency. When asked by the NTSB about experience with or knowledge of how to respond to a natural gas odor, several Palmer employees cited personal experience with or knowledge of natural gas in their homes or those of their neighbors.

#### 1.8.1.3 Equipment Maintenance

The Palmer CEO and VP stated that maintenance department mechanics were responsible for repair and maintenance of most production equipment. They told the NTSB that when employees identified an issue, they were to report it to the maintenance department, which decided whether the issue would be addressed by in-house mechanics or by hiring a contractor. The Palmer CEO and VP further stated that these mechanics generally were trained on the job (meaning very little formal or classroom training on their job duties) and that, because maintenance and repair of natural gas appliances fell outside the maintenance department's scope of work, it was typically performed by a contractor. The Palmer CEO indicated, however, that Palmer maintenance staff "might check for a leak."

The NTSB interviewed a Palmer chocolate unloader, who recalled smelling a gas odor near the boiler house east of Building 1 on March 23, 2023, the day before the accident. He then checked the boiler house gas meter for leaks and found none. The chocolate unloader told the NTSB that checking for leaks was not a standard procedure of Palmer's, but one based on his own personal maintenance experience.

Palmer had a safety committee made up of employees and managers from various shifts and job titles that met monthly to discuss potential safety issues with equipment or operations and how to fix these issues.[69] According to Palmer management, inspections for tripping hazards, machine guards, blocked emergency exits, and other issues took place weekly. Employees could also raise safety issues or potential issues to the committee. The NTSB interviewed Palmer employees who had attended safety committee meetings over the years, and none recalled discussing gas operations or emergency response to natural gas emergencies in the meetings.

The contractor who maintained Palmer's natural gas–fueled appliances reported to the NTSB that they had not performed any work on the appliances in the 3 years before the accident.

## 1.8.2 UGI Corporation

### 1.8.2.1 Procedures

UGI's *Gas Operations Manual* (GOM) outlined procedures for first- and second-party excavation activities.[70] The GOM did not require crews to contact PA One Call when using "soft dig" methods like vacuum extraction or shallow tilling but suggested crews use the service to locate other utilities in the area. The GOM did require crews to contact PA One Call when using mechanical equipment (for example, excavators, jackhammers, or pavement saw cutters).

UGI's *Emergency Plan* included emergency procedures for UGI personnel to take when reacting to an explosion, fire, or both that may be caused by a release of gas from UGI assets. The procedures covered both indoor and outdoor leaks and specified actions UGI personnel must take when arriving on scene, contacting local authorities, and dealing with natural gas assets involved in a release. The plan specified that if it is unclear which valves need to be closed, a UGI first responder must contact central dispatch, a senior area engineering manager, or the on-call engineering leader to determine which valves to close and other steps to isolate the system.

[69] Palmer's natural gas–fueled equipment and appliances, described earlier in this section, fell under the scope of the safety committee.

[70] *First-party excavation activities* are conducted in a pipeline's right-of-way by the pipeline operator's own personnel. *Second-party excavation activities* are conducted by a contractor.

### 1.8.2.2 Integrity Management

Integrity management (IM) programs identify, assess, and manage pipeline safety risk. In pipeline IM plans, the risk of an adverse event is the product of both its likelihood and its consequences. IM is a continuous, iterative process in which information on risk is gathered, risk is reduced or mitigated, and risk is reevaluated, with the IM process evolving over time. In some cases, as with UGI, IM programs are required by regulation.[71]

UGI used incident data maintained by PHMSA as its system of record for incident information. Before March 24, 2023, UGI attributed no incidents to Aldyl A service lines or mains. According to PHMSA data, UGI reported nine significant incidents involving the company's assets since 2010. Aside from the accident discussed in this report, UGI attributed the other incidents to damage from natural force, excavation, or other outside force; incorrect operation; and material failure.[72]

#### 1.8.2.2.1 Risk Management

UGI IM staff told the NTSB that the program managed pipeline risks by completing targeted assessments; reducing risks through repairs, replacements, or other actions; and continual evaluation and improvement. UGI required periodic inspections and patrols but did not require any additional integrity assessments on its assets in the vicinity of the accident site.[73]

UGI's DIMP was centrally managed and administered. Inspections required by UGI's GOM were the primary data sources that UGI personnel used to collect information on distribution assets. The DIMP used a relative risk model for evaluating gas mains to guide decisions about asset replacement. The DIMP also used quantitative and subject-matter expert (SME) model (that is, qualitative evaluation) to identify asset risks.

[71] UGI is required by 49 *CFR* Part 192 Subpart P to have a gas DIMP.

[72] One of the material failure incidents occurred on July 2, 2017, in Millersville, Pennsylvania, and involved a plastic service line installed in 1998. The other occurred on December 25, 2020, in Swiftwater, Pennsylvania, and involved a plastic main installed in 2019.

[73] *Integrity assessments* are elements of an IM program by which operators evaluate the condition of pipelines or assets subject to identified threats and take actions to mitigate the threats, if identified. UGI had reviewed and evaluated the threats in its assets near the Palmer facilities and had determined no integrity assessments were warranted.

UGI DIMP documents listed the *Guide for Gas Transmission, Distribution, and Gathering Piping Systems* (GPTC Guide), managed by the Gas Piping Technology Committee (GPTC), as one of the references used to develop and maintain this program.[74] The GPTC Guide describes heat sources and steam pipes as hazards to plastic gas mains and services that should be evaluated. The guide also provides information on the evaluation of plastic gas main and service line installations near heat sources to determine mitigative measures. The GPTC Guide further notes that to assess the applicable threats and risks to natural gas pipeline systems, a pipeline operator's DIMP must identify the characteristics of the pipeline's design and operations along with significant environmental factors. A DIMP must also collect information on steam pipes or other heat sources causing elevated temperatures and must provide the information to the IM program for evaluation.

UGI's system of record for natural gas main data and leak survey results was Smallworld GIS, and its system of record for service lines was an in-house gas service web application. At the time of the accident, UGI had captured no data in these systems about privately owned subsurface assets. UGI likewise did not record any damage to privately owned assets in any of its databases; further, PA One Call required excavators to report such damage, and if UGI reported such damage, the damage would be logged by UGI's claims team. UGI training did not provide any instruction to field personnel on steam lines or other private assets as possible threats to natural gas assets.

#### 1.8.2.2.2 Risk Models

At the time of the accident, UGI used three risk models to identify and evaluate risks to the pipeline distribution system: (1) the Optimain model, used exclusively for prioritizing gas main replacement; (2) the data-driven risk model (DDRM); and (3) the SME risk model; the latter two models were used to identify risk in gas mains and service lines. The threat categories used in UGI's risk model were (1) corrosion; (2) natural forces; (3) excavation damage; (4) other outside force damage; (5) pipe, weld, or joint failure; (6) equipment failure; (7) incorrect operation; and (8) other, such as exceeding service life.[75]

[74] GPTC is a consensus group comprised of industry representatives and government regulators that develop guidance for the natural gas operators on practices and procedures to comply with requirements of federal pipeline safety regulations.

[75] Operators are required by 49 *CFR* 192.1007(b) to consider specific threat categories in their IM programs.

The DDRM was a quantitative model that estimated the probability and consequence of failure for asset groups based on the type of asset, pressure, material, and other factors. UGI used the SME risk model to validate the findings of the DDRM and, when applicable, to evaluate risk at a more granular level than was possible in the DDRM.

In the SME model, a total risk score was derived from an SME assessment of a DDRM asset group and threat to pipeline integrity. SMEs determined probability factors for asset failure based on whether each threat contributed to failure and the extent to which the threat had been observed by UGI. The model also assigned a consequence factor, developed by UGI to amplify the magnitude of the consequence for identified asset types. UGI had not developed a consequence factor for Aldyl A fittings, evaluating the threat and consequences of Aldyl A to be the same as other polyethylene fittings.

After the accident, UGI provided the NTSB with an estimation of the extent (amount) of Aldyl A in its system.[76] Reported Aldyl A and potential Aldyl A are shown in table 3.[77]

**Table 3.** Estimated UGI Aldyl A and total assets.

| Material Category | Main (miles) | Active Services (number of lines) | Retired Services (number of lines) |
|---|---|---|---|
| **Reported Aldyl A (1965–2001)** | 32 | 1,211 | 48 |
| **Potential Aldyl A (including reported installation dates of 1965–1986)** | 636 | 86,891 | 6,482 |
| **Total, any material** | 12,337 | 617,069 | Unknown |

[76] UGI estimated the amount of Aldyl A by identifying in Smallworld GIS and its gas service web application all DuPont-manufactured pipe installed from 1965 to 1991, Uponor-manufactured pipe installed from 1991 to 2001, or pipe classified with Aldyl A as its material type.

[77] Historical records of natural gas pipeline operators often indicate only that a pipe material is polyethylene and do not necessarily specify the type of polyethylene. In its review of records, UGI identified situations in which piping may be Aldyl A but was not reported as such, referring to these as "potential Aldyl A."

Before the explosion, UGI had studied records of leaks and failures associated with the Aldyl A tees with the Delrin insert. The study concluded that these tees had a history of leakage from the black service tee caps. It further stated that leaks had been found through normal operations, leak surveys, and odor complaints and had not resulted in serious consequences.

UGI stocked repair kits for Aldyl A service tees, which modified the tees and eliminated the black caps, but did not mandate that crews use the repair kits whenever they encountered Aldyl A.[78] After the accident, UGI estimated that from 2020 to 2023, a total of 3,193 Aldyl A repair kits had been issued to field crews.

#### 1.8.2.3 Pipeline Safety Management System

Representatives from UGI stated that the company began implementing their pipeline safety management system (PSMS) in 2015. In 2019 and again in 2024, UGI used a self-assessment model to evaluate its PSMS maturity, which UGI recorded as "developing" with several elements implemented.[79] In 2022, UGI established a PSMS Governance Committee that focused on continuous improvement by addressing priorities within each PSMS element.

#### 1.8.2.4 Public Awareness Program

UGI's public awareness program in the West Reading area informed its customers about the natural gas distribution and transmission system, signs of a pipeline leak, and what to do if a gas odor is detected. A section of UGI's website titled "Smell Gas? Act Fast!" contained a contact number for UGI and instructions to leave the area and to call UGI, 9-1-1, or both.

A UGI representative provided the NTSB a summary of its public awareness efforts for Palmer, specifically for Buildings 1 and 2. These included mailings of scratch-and-sniff brochures in both English and Spanish to Building 1 in December 2022 and January 2023, a February 2020 advertisement in the *Reading Eagle*, and booths at a Reading Phillies game in August 2018 and at Junior League of Reading touch-a-truck events from 2016 to 2019. Ongoing efforts included gas safety classes

[78] UGI stated one of its regions (UGI North) had installed repair kits anytime crews encountered Aldyl A service tees with black caps while working on replacement projects.

[79] These include hiring a full-time PSMS lead, updating its Governance Committee charter, and considering PHMSA advisory bulletins and NTSB recommendations into its incident investigations.

at local schools, on-hold messaging at the UGI call center, social media posts, and bill stuffers.

The NTSB reviewed UGI's data on the effectiveness of its public awareness messaging to stakeholder audiences.[80] The data indicated that 62% of respondents recalled receiving information from a pipeline company within the past 2 years, and 36% did not. A UGI survey from 2020 indicated that, within the stakeholder category of the affected public, about 31% had read all or some of UGI's natural gas safety bill stuffer, 21% had "just scanned it," 38% did not know whether they had read it, and 8% had not read it. Data from a 2022 UGI report on its public awareness program effectiveness showed that 41% considered themselves somewhat well-informed about pipelines in their community, 31% considered themselves either not at all or not too informed, and that 27% considered themselves very well-informed. The same report contained data on what respondents would do in a pipeline emergency, with 86% of respondents stating they would call 9-1-1, 62% stating they would flee the area, and 42% stating they would call the pipeline company.[81]

## 1.9 Postaccident Actions

### 1.9.1 Occupational Safety and Health Administration Investigation

OSHA opened an investigation into the accident and issued Palmer two serious and six other-than serious violations.[82] These violations are summarized in table 4.[83]

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[80] These data are contained variously in UGI's 2020 Effectiveness Measurement, UGI 2022 Effectiveness Measurement, and UGI Four-Year Evaluation (2020).

[81] Respondents were able to select more than one answer.

[82] (a) A *serious violation* as designated by OSHA exists when a workplace hazard could cause an accident or illness likely resulting in death or serious physical harm, unless the employer did not know or could not have known of the violation. *Other-than-serious* is a violation directly related to job safety and health but not serious in nature. (b) Palmer contested the violations.

[83] OSHA initially cited Palmer under the general duty clause of the Occupational Safety and Health Act of 1970 for failing to evacuate workers during a natural gas leak that resulted in an explosion causing multiple fatalities. During abatement of the citations, OSHA withdrew the general duty citation and replaced it with a citation under the Emergency Action Plan standard, 29 *CFR* 1910.38, as described in section 1.7.3. As part of the settlement agreement, Palmer agreed to several actions, including a specific natural gas leak procedure and training of its employees. It is stated in the agreement that these actions were not required of the company before the accident.

**Table 4.** Palmer OSHA-issued violations.

| Regulation | Type | Basis |
|---|---|---|
| **29 *CFR* 1910.38(f)(2)** | Serious | Palmer failed to review its emergency action plan elements (such as fire, hazardous chemicals, and electrical emergencies) with employees covered by the plan when the employees' responsibilities under the plan changed |
| **29 *CFR* 1910.305(g)(2)(ii)** | Serious | Flexible cords in heat tape used to warm chocolate pipes between Buildings 1 and 2 were not spliced or tapped as required by regulation |
| **29 *CFR* 1910.37(b)(2)** | Other-than-Serious | No exit sign on a Building 1 basement door as required by regulation that each exit must be clearly visible and marked |
| **29 *CFR* 1904.29(b)(2)** | Other-than-Serious | An OSHA 301 incident report form or equivalent was not filled out for each of 10 employee injuries or illnesses entered in the OSHA 300 log or equivalent[1] |
| **29 *CFR* 1904.29(b)(3)** | Other-than-Serious | Seven workplace-related deaths and 3 serious workplace-related injuries were not entered on the OSHA 300 log or equivalent within 7 calendar days of receiving information that a recordable injury or illness has occurred |
| **29 *CFR* 1904.40(a)** | Other-than-Serious | The OSHA 300 log or equivalent was not provided to an authorized government representative within 4 business hours |
| **29 *CFR* 1910.1001(j)(3)(i)** | Other-than-Serious | Palmer did not determine the presence, location, or quantity of asbestos-containing materials or presumed asbestos-containing materials at the worksite or exercise diligence in informing employees about them |
| **29 *CFR* 1910.1200(h)(1)** | Other-than-Serious | Palmer failed to train employees and temporary workers on the hazardous chemicals in the workplace including, but not limited to, ethyl alcohol |

[1] OSHA 301 incident forms and OSHA 300 logs are the official records of workplace-related injuries or illnesses submitted by an employer.

### 1.9.2 Pennsylvania Public Utility Commission

After the explosion, safety staff from the PA PUC Bureau of Investigation and Enforcement asked UGI about leaks and work in the West Reading area. The PA PUC staff elevated their presence throughout the West Reading area in the months after the explosion. On April 10, 2023, the PA PUC sent a letter advising UGI to stop any planned work involving joining assets to Aldyl A piping until the company reviewed its standards, procedures, plans, and training related to Aldyl A piping and other "first-generation plastics." Further, the PA PUC recommended UGI review its public awareness program and its messaging to non-English-speaking populations.

### 1.9.3 R.M. Palmer

Since the accident, Palmer has completed the following actions:

- Developed a procedure for how employees should respond to a natural gas leak and trained supervisors and management on it. The procedure directs employees to stop work if an odor is detected; determine whether the odor could be dangerous, such as the rotten-egg smell of natural gas; and evacuate immediately if so, or if employees begin to feel unwell. The procedure also notes that the maintenance department now has a portable natural gas detector that may be used to help detect natural gas.
- Installed in all its buildings externally monitored natural gas alarms. The alarm company calls Palmer supervisors when natural gas safety levels are exceeded. According to the new natural gas procedure, supervisors who are notified by the alarm company must evacuate the workers immediately using the Palmer intercom system.
- Developed an annual English- and Spanish-language workplace emergency safety training program for all employees. The training includes odor awareness with a scratch-and-sniff card to familiarize employees with the smell of natural gas.
- Removed the natural gas heaters and gas piping from the basement of the other production buildings and replaced them with electric heaters.

### 1.9.4 UGI Corporation

Since the accident, UGI has completed the following actions:

- Conducted walking leak surveys in the area of the accident site and mobile leak surveys of all bare steel and plastic mains installed before 1989 in West Reading.[84]
- Reviewed its Aldyl A assets and developed a new database entry for plastic pipe and fittings in its database to allow evaluation of the specific types, vintages, and sources of plastic pipe and fittings historically installed by UGI and its predecessor companies.
- Developed a new procedure to standardize the remediation of Aldyl A tapping tees, which uses electrofusion repair fittings developed specifically for the tees and updated related operational procedures.[85]
- Created retirement guidance for all service tees with added GPS data showing the location of retired service tees.
- Evaluated procedures related to discovery or exposure of unmarked assets.
- Adjusted its IM program, revising procedures to add information collection requirements for plastic pipes when exposed as part of other activities, incorporating data collection and digitization of material failure reporting, and adding a records correction form to the GIS revision and asset data correction process.
- Created an electronic database in which to record information on distribution system risks and threats, along with a program to train SMEs on its use.

[84] (a) In a *walking survey*, a technician walks near or over gas mains and service lines and up to each meter set in the survey area while carrying a handheld leak-detection instrument. (b) *Mobile leak surveys* deploy vehicles (such as cars or aircraft) with mobile data collection equipment to detect elevated methane concentrations.

[85] An *electrofusion repair fitting* is a plastic pipe fitting with a built-in heating element that melts the plastic at the joining interface, creating a weld.

- Requested that GPTC revise its guidance to recommend natural gas distribution system operators replace or remediate Aldyl A tapping tees and Delrin inserts whenever these are encountered in the field.[86]

- Modified its public awareness program, revising current public communications on "what to do if you smell gas" (including a scratch-and-sniff card) and hiring a communications agency to deploy a new natural gas safety campaign for the general public, with expanded Spanish-language communications. UGI also deployed a public awareness pilot program, meeting with facilities managers for 128 of their largest nonresidential customers, and distributing natural gas safety awareness communications kits. UGI reported that the pilot program was well received, and customers often requested more materials.

- Evaluated its public communications to see where it could share information on natural gas alarm availability and implemented a training program for state police and fire investigators.

- Replaced natural gas mains in the immediate vicinity of the accident site and along Penn Avenue from 2nd Avenue to Park Road.

- Identified 34 natural gas customers in its service territory that could be operating below-ground steam systems to determine whether these systems conflicted with UGI assets. UGI found 14 of these customers that required further investigation on whether the systems conflict with UGI assets and should be remediated. UGI is also applying a risk index model to each of the 14 customer locations with potential conflicts between UGI assets and customer-owned, below-ground steam systems. As conflicts are identified, UGI will initiate remediations that will include, if necessary, the relocation of UGI assets, replacement with steel mains or service lines, or both.

- Updated its general installation requirements in the GOM and the Pennsylvania Design One Call cover letter and issued a companywide technical advisory bulletin to continue identifying heat-generating

[86] GPTC voted to approve UGI's recommendation. See BSR-GPTC-Z380.1-2022-TR-2023-14.pdf (aga.org)

sources and to raise awareness for field employee escalation when these sources are discovered.

- Requested that West Reading Borough and the Western Berks Water Authority replace the water valve box cover at South 2nd Avenue and Penn Avenue with an appropriately marked cover and that they confirm that none of their water valve covers are marked as gas covers.

- Modified its valve inspection program, implementing a geospatial collection system to locate and document valves; updating procedures for valve identification, validation, record keeping, and for when discrepancies are found in the field; and adding marker balls to all excavated valves.

## 1.10 Pennsylvania Public Utility Commission Party Removal

In accordance with federal regulations, the NTSB designated PA PUC as a party to this investigation based on its oversight of UGI as a natural gas pipeline operator in Pennsylvania and because the PA PUC could provide technical personnel to assist in the investigation, which it did.[87] In June 2023, the NTSB requested that the PA PUC produce its inspection reports of UGI's DIMP for the 5 years before the accident.[88] The PA PUC declined to provide the reports, citing state confidential security information nondisclosure laws. The PA PUC's interpretation of these laws considered the NTSB to be a "member of the public," thus requiring the information to be withheld.

In September 2023, the NTSB revoked the PA PUC's party status for violating NTSB party guidance by not providing the requested inspection reports.[89] Also in September, the NTSB issued a subpoena to the PA PUC to produce the inspection reports. After lengthy legal action, the NTSB obtained the reports from the PA PUC on April 23, 2024, more than 9 months after the investigation identified the need for them.

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[87] See 49 *CFR* 831.11.

[88] UGI provided the DIMP reports themselves to the NTSB on April 19, 2024.

[89] A description of the NTSB party system and the guidance provided to parties can be found on the NTSB's website.

# 2 Analysis

## 2.1 Introduction

On March 24, 2023, around 4:55 p.m. local time in West Reading, Pennsylvania, natural gas leaked from a crack in a retired Aldyl A service tee with Delrin insert into the basement of Palmer Building 2 and ignited, causing an explosion and fire that killed 7 Palmer employees, injured 10 people, destroyed Building 2, and damaged another Palmer building.

The analysis will discuss the following safety issues:

- Degradation of a retired Aldyl A service tee that was accelerated by elevated ground temperatures from a corroded and cracked steam pipe nearby.
- UGI's insufficient consideration of pipeline integrity threats, particularly Aldyl A service tees with Delrin inserts at elevated temperatures.
- Presence of unmarked and unreported private assets crossing public rights-of-way, excluding them from PA One Call and increasing the risk of damage to them.
- Delayed evacuation of Palmer's Building 2 despite detection of natural gas by employees and others.
- Natural gas safety messaging from pipeline operator public awareness programs that may not reach certain members of the public.
- Insufficient guidance on natural gas emergency procedures.
- Absence of natural gas alarms in commercial buildings.
- Insufficient accessibility of gas distribution line valves.

The NTSB's review of the circumstances that led to this accident found the following areas either were not factors in or were not causal to the accident:

- *Pipeline overpressurization*. The pressure at the Cherry Street main at the time of the accident was about 53 psig, lower than the system's maximum allowable operating pressure of 60 psig.
- *Local emergency responder actions*. The response of the fire departments and law enforcement agencies was timely and appropriate. Emergency response personnel were on the scene even

before the first 9-1-1 call, and there was no indication that the response exacerbated any injuries.

Therefore, the NTSB concludes that neither of the following issues were causal to the accident: (1) pipeline overpressurization or (2) local emergency responder actions.

## 2.2 The Accident

About 4:55 p.m. on March 24, a natural gas–fueled explosion and fire destroyed Palmer's Building 2, killed 7 people, and injured 10 others. The explosion damaged Building 1 to the south of Building 2 and an apartment building to the north, displacing 3 families.

At least 13 minutes before the explosion, multiple Palmer employees reported smelling a gas odor in both Buildings 1 and 2.[90] The smell was strong enough to cause some employees to leave the buildings. Many other employees—including several who were killed in the explosion—were in the buildings when the explosion occurred. Some surviving employees indicated they did not know what to do about the odor, and others stated they had remained in the buildings because they were concerned that evacuation would count against their workplace attendance. Three of the victims entered Building 2 just before the explosion in an apparent attempt to find the source of the gas odor. All seven people killed in the accident were inside Building 2 at the time of the explosion.

Local and state emergency services arrived on the scene just after the accident to begin firefighting and rescue operations. Flash fires were observed above and around the firefighters as they moved about the accident site, and firefighters recalled a gas-fed fire in the basement of Building 1 coming through a chocolate pipe conduit between the two buildings, indicating gas was still burning after the initial explosion. About 5:00 p.m., the City of Reading Fire Department contacted UGI, and UGI first responders subsequently isolated the gas system around 6:15 p.m. The fires were extinguished soon after.

### 2.2.1 Source of Natural Gas that Fueled the Explosion

An investigation conducted by local, state, and federal law enforcement determined that the explosion and fire originated in the southwest quadrant of the

[90] A Palmer employee recalled smelling gas near the boiler room behind Building 1 the day before the accident, but the investigation did not determine that this was related to the leak at Building 2.

Building 2 basement, where natural gas had accumulated until it reached an explosive concentration and ignited, and that the ignition source was unknown.

Bar hole tests conducted 6 days after the accident showed underground gas concentrations near the Cherry Street and South 2nd Avenue intersection, which, at the time, was the closest accessible area to the explosion site. The tests indicated that gas had leaked from the distribution system on Cherry Street and spread underground. When a leak source is below ground, paved surfaces like roads or walkways inhibit natural gas from venting, resulting in further migration underground and through paths like cracks or holes. Further bar hole tests conducted on April 22, about a month after the accident, showed residual gas underground near the Building 2 service line.[91] The bar hole tests showed that enough gas had been present underground at the time of the accident to still cause residual gas measurements a month later.

A law enforcement investigation report indicated that natural gas had entered the basement of Building 2 in the area where the chocolate conduits entered the basement, as well as through a crack in the building foundation and a location where an unused gas pipe entered the building.

Postaccident visual examinations of the chocolate pipe conduits revealed an unobstructed pathway for airflow between Palmer Buildings 1 and 2. To determine whether natural gas could flow between the buildings, the NTSB observed as a deputy fire marshal placed a smoke generator in the basement of Building 2. NTSB investigators saw the smoke emanating from the ground next to the Building 2 basement, close to the service line, indicating a path between the basement of Building 2 and the ground surrounding the gas distribution system. The NTSB saw smoke exiting the conduits in the basement of Building 1, confirming the ability of gas to flow from the Building 2 basement to the Building 1 basement through the conduits. The NTSB also found smoke on the third floor of Building 1. This observation was consistent with employee reports of a gas odor in various areas of Building 1 before the accident. These examinations and tests indicated that natural gas had been escaping from UGI's gas distribution system in the vicinity of Cherry Street into the ground and from there migrating to the Building 2 basement, through the chocolate pipe conduits, and to Building 1.

To determine the point of natural gas release from the distribution system, the NTSB conducted incremental pressure testing and excavations. With these tests the NTSB identified three leaks coming from the gas distribution system near the

[91] Between the March and April bar hole tests, some of the gas had vented through previous bar holes, cracks, and open areas in the pavement.

southwest quadrant of Building 2.[92] The largest leak was at the Building 2 service tee that had been retired in 1982 and capped off but was still connected to the natural gas distribution system at full gas system pressure, as was UGI standard and common industry practice. The NTSB Materials Laboratory examination of the tee revealed that it was fractured through its tower from the top to nearly the bottom, forming a 1.9-inch crack that was open at one end. The insert was completely fractured near the bottom, and its upper portion and cap were not present, providing an open path for gas to escape. Slow crack growth features of the fracture, discussed below, indicated that the crack had been present before the explosion. Therefore, the NTSB concludes that natural gas migrated from the Aldyl A retired service tee through the ground then into the Palmer Building 2 basement, chocolate pipe conduits, and Building 1, and fueled the explosion in the Building 2 basement.

Further examination of the longitudinal fracture in the tower shell of the retired service tee to Building 2 revealed that it was flat and featureless with fibrils, transitioning to hackle near the base of the tower, which is indicative of slow crack growth. The retired service tee's Delrin insert had a through-wall fracture that showed crazing on the side closest to the steam pipe and porous and granular features elsewhere. The outer surface of the Delrin insert showed surface cracking and volume loss, indicative of decomposition.

The main factors driving slow crack growth are stress, temperature, and material susceptibility. Polyethylene pipe specifications provide limits on pipe operations and operating environments that include the temperature of the operating environment. Operating outside of these environments can accelerate the rate of defect growth. The specifications for Aldyl A piping systems, which included service tees with Delrin inserts, indicated a maximum ground temperature of 100°F. The slow crack growth in the Aldyl A tower shell and the thermal decomposition of the Delrin insert were consistent with exposure to elevated temperatures, although the investigation could not determine the exact ground temperatures surrounding the Building 2 service tee before the accident. The susceptibility of certain Aldyl A polyethylene resins to slow crack growth has been documented extensively and is discussed below (Palermo 2011, Haine 2014). Because the growth rate of such cracks increases exponentially with temperature, small increases in temperature can lead to comparatively large changes in crack growth rate.

[92] A small leak in the active polyethylene service line to Building 2 exhibited a cut in the line that the NTSB determined was consistent with damage from the explosion. Another leak was identified in the NTSB Materials Laboratory on the Aldyl A gas main underneath the 2021 replacement service tee; having a measured flow rate of 0.6 standard cubic feet per hour, the NTSB determined this leak was very small and did not contribute to the accident.

Published data indicate that Delrin polyacetal will start to show signs of aging with time and that higher temperatures accelerate the onset of aging effects (Delrin 2024).[93] However, the service tee at Building 1 also contained a Delrin insert from 1982 but did not exhibit any of the material degradation of the retired Building 2 tee insert. Although the 40-year-old Delrin Building 2 service tee insert might have aged in any thermal environment, its extensive material degradation (particularly when compared to the Building 1 service tee insert, which had been installed at the same time) indicates that, as with the Aldyl A tower shell, the temperature in the surrounding environment had been significantly elevated for enough time to facilitate the degradation. Thus, the service tee and the Delrin insert were likely exposed to elevated temperatures for a sustained period of time, which led to slow crack growth and thermal decomposition, respectively, that allowed natural gas to be released from the gas distribution system. The NTSB concludes that the 1982 retired service tee leaked because of degradation caused by exposure to elevated temperatures; more specifically, slow crack growth of the Aldyl A tower shell and thermal decomposition of the Delrin insert.

Running perpendicular to the Cherry Street natural gas main, about 2 feet to the west of the retired tee and about 15 inches above it, was a steam pipe owned by Palmer.[94] The pipe was part of a steam heating system used seasonally to provide heat to parts of Building 2. When the NTSB excavated the section of Cherry Street that contained the natural gas main and Building 2 service tees, a section of the Palmer steam pipe was found heavily corroded, with a 4-inch through-wall crack. The NTSB further examined the cracked segment of the steam pipe and determined the wall had been corroded to less than 20% of its original thickness in the vicinity of the crack. The corrosion-induced wall loss on the pipe would have significantly reduced the force needed to cause it to crack. The location of the crack indicated that, at some point before the accident, an external load had been applied to the steam pipe that exceeded its shear strength where the pipe wall had been thinned extensively by corrosion, causing the pipe to shear locally and the crack to form.

Finite element simulations conducted by the NTSB Materials Laboratory found that in the most probable scenarios, the heat from an intact steam pipe could only increase the ground temperature near the retired tee by about 27°F to 40°F above

[93] For example, samples of select grades of Delrin stored at 135°F to 140°F showed a notable loss of tensile strength after about 7 years. The same types of samples stored at room temperature retained their strength after 20 years.

[94] This steam pipe was about 25 to 30 feet from the Building 1 service tee.

the baseline ground temperature. In other words, without the crack, the steam pipe had limited capacity to increase the temperature of its surroundings.

As noted above, the NTSB found a small crack in the Cherry Street gas main underneath the active service tee to Building 2. The 0.39-inch crack in the gas main, which was also made of Aldyl A, was too small to have contributed to the accident, but it also exhibited features consistent with progressive slow crack growth that further indicated a significantly elevated temperature environment. The crack surfaces exhibited start–stop features consistent with thermal expansion and contraction of the service tee saddle and undersaddle, also known as thermal stress cycling, likely due to fluctuations in ground temperature as high-temperature steam flowed periodically through the pipe based on heating demand in Building 2 and escaped through the steam pipe crack.[95]

The NTSB also examined a collapsed plastic marker ball, first installed in 2021, that had been recovered from the accident site and determined that the ball's seam had ruptured in a manner consistent with a buildup of internal pressure inside the ball caused by an elevated temperature environment. The same thermal fluctuations in the ground temperature that caused thermal stress cycling in the Cherry Street gas main subsequently collapsed the ball inward. Collapsed marker balls are rarely, if ever, encountered in routine utility work, indicating that seasonal changes in ground temperature likely did not contribute to the state of the marker ball. The high temperatures needed to degrade the retired service tee, initiate slow crack growth in the Cherry Street gas main, and rupture the marker ball seam were consistent with direct release of steam into the ground surrounding the steam pipe and retired service tee.[96] Therefore, the NTSB concludes that steam escaping through the crack of the corroded steam pipe significantly elevated the ground temperature at the location of the retired service tee, which accelerated its degradation and ultimately led to its failure.

[95] The NTSB considered whether the heat tape that had been affixed to the outside of the chocolate pipes could have caused elevated ground temperatures and determined it could not have raised the ground temperature enough to cause the degradation of the retired service tee. The pipes were situated inside a larger pipe conduit, and the air inside the conduit likely prevented direct heat transfer to the ground.

[96] Further, had the retired service tee displayed the level of degradation in 2021 that was visible upon postaccident excavation, the UGI crew would not have been able to complete the tee replacement project, which required them to install a threaded service tee cap and conduct a soap test to make sure the tee was free of leaks.

The NTSB reviewed an image of the UGI crew taken by Palmer during the 2021 service line replacement project. The image showed that UGI had been excavating with mechanized equipment around the same location as the crack in the steam pipe. Further, a UGI crewmember stated in an interview with the NTSB that a subsurface white powder, later determined to be calcium carbonate, had been visible during the 2021 excavation. The NTSB did not determine the purpose of the powder, but it further indicated the proximity of the UGI work to the steam pipe itself, as the powder was visible both in the Palmer photograph and when the NTSB excavated a section of Cherry Street after the accident. A review of PA One Call records did not show any other excavation projects in this area since 2021. The shearing of the pipe is consistent with loss of soil support that left the steam pipe vulnerable to shear and failure given the localized corrosion.[97] However, it could not be determined what specific event or events caused the pipe's ultimate failure. Further, evidence recovered from the scene did not indicate why more extensive corrosion had occurred where the pipe failed.

In an interview with the NTSB, a truck driver who made daily deliveries of chocolate to Palmer's West Reading facilities recalled that, at some point after the UGI service tee replacement and gas meter relocation project on February 16, 2021, he would occasionally see steam rising from the section of asphalt pavement that UGI had replaced during the project. He did not recall seeing the steam before the project. This recollection is consistent with the steam pipe cracking and beginning to release steam and heat into the ground sometime between the UGI service tee replacement project and the accident.

Palmer management was aware of UGI's meter relocation project and, according to recollections from a UGI crewmember, of the location of the steam pipe as well. Palmer records indicated that the steam heating system boiler unit was inspected annually by one of their maintenance contractors and checked daily by Palmer mechanics; however, Palmer did not have maintenance records on the steam pipe itself. The extensive corrosion found on the steam pipe in the area of the crack further indicated the pipe had not been maintained. Therefore, the NTSB concludes that Palmer's lack of awareness of corrosion-induced wall loss on the steam pipe from Building 1 to Building 2 left the steam pipe vulnerable to localized shear and cracking when external loads changed, which led to steam heating the ground near the retired service tee after UGI's 2021 service tee replacement project.

[97] External corrosion was observed along the entire length of the steam pipe when it was exposed after the accident. Although the remaining wall thickness was measured at some locations, the detailed evaluation focused on the portion that contained the through-wall crack. This section was sent to the NTSB Materials Laboratory.

### 2.2.2 Delayed Evacuation

At Palmer's facilities in West Reading, natural gas was used for the Building 2 basement heating system, the boiler for the steam heat system, and a backup generator. In interviews with the NTSB, Palmer management characterized the risk associated with a natural gas leak as "low" because they had few natural gas–fired appliances at that location. The perception was that the possibility of any natural gas leak would therefore be relatively minimal. The company's emergency plan manual, the Red Book, listed UGI's emergency number and contained floor plans with utility shut-off locations but lacked a procedure for when to use the number or how to shut off the gas. The company's crisis management plan listed various potential threats to business operations but did not include a natural gas emergency in this list. Likewise, the Red Book contained procedures on how to respond to some of these threats but not to natural gas. Palmer did not provide employee training on natural gas hazards and how to respond to the smell of gas.

The flammable and explosive hazards of natural gas have long been recognized by the pipeline industry. To reduce the chances that natural gas leaks will go undetected, federal regulations require the addition of an odorant to natural gas distribution pipelines. General best practices for when natural gas is detected are to immediately evacuate to a safe distance and then call either the gas operator or 9-1-1. For example, UGI's website instructs anyone smelling a gas odor to "act fast" and leave the area and call UGI, 9-1-1, or both.

Employees working in both Buildings 1 and 2—and some outside of the buildings—recalled smelling gas or a strange odor on the afternoon of March 24, 2023. In interviews with the NTSB, many Palmer employees stated that they knew that the distinctive sulfurous odor indicated natural gas, but others recalled expressing initial confusion as to what the smell was. Some employees asked their supervisors for guidance but were not told to evacuate; one employee in Building 1 and another in Building 2 self-evacuated. Witness accounts and surveillance camera data indicated that many employees in Building 2 at the time of the accident had been aware of the gas smell at least 13 minutes before the explosion. None of the employees that were aware of the natural gas odor pulled the fire alarm when it was detected, and Palmer management did not issue an evacuation order.

Palmer's CEO told the NTSB that employees were empowered to evacuate for safety reasons. But some employees interviewed after the accident stated that they did not evacuate Building 1 even after smelling gas because they were concerned it would count against their workplace attendance. A survivor of the explosion, who was in Building 2 when it exploded and had smelled gas there, told the NTSB that she thought employees were supposed to wait for instructions from their supervisor in such a situation. Surveillance camera data and interviews with other Palmer employees indicated that the lead mechanic, human resources director, and plant manager were in the process of investigating the leak at the time of the explosion, in which all three were fatally injured. Without a natural gas emergency evacuation procedure, Palmer management and employees were not offered a clear understanding of the critical danger of a natural gas leak; even Palmer management did not know to immediately evacuate the building in case of a natural gas odor.

The Red Book contained an orderly evacuation procedure for general emergencies that Palmer employees were trained on as part of regularly conducted fire drills. Fire alarms, triggered manually or by automatically operated smoke or fire detectors, indicated to employees that they should evacuate. The NTSB reviewed company records of past fire drills and evacuations and found that an orderly evacuation could take place in under 5 minutes.

Further, had someone pulled the fire alarm once the odor was reported in Building 2 (13 minutes before the explosion), it is likely that employees could have evacuated with enough time to reach a safe distance from the eventual explosion. Therefore, the NTSB concludes that had Palmer implemented natural gas emergency procedures and trained their employees and managers on them before the accident, the employees and managers could have understood the danger they faced and could have responded by immediately evacuating and moving to a safe location away from both buildings. Since the accident, Palmer has installed natural gas alarms in all their buildings, developed an annual workplace safety training program in both English and Spanish, replaced natural gas heaters in all their buildings with electric heaters, and developed an emergency procedure for how to respond to a natural gas leak.

Palmer's new procedure tells employees to determine whether an odor could be dangerous before deciding to evacuate and notes that portable natural gas detectors are available to help detect natural gas. The NTSB is concerned that by telling employees to judge whether an odor is dangerous—and by noting the availability of portable natural gas detectors—the new procedure could lead to employees investigating natural gas odors rather than immediately evacuating to a safe location. Three of the employees fatally injured in this accident were investigating the gas odor at the time of the explosion instead of evacuating. Therefore, the NTSB recommends that Palmer revise its natural gas emergency procedure to direct all employees to immediately evacuate upon smelling natural gas odorant and to specify a safe evacuation location.

## 2.3 Insufficient Consideration of Known Threats from Plastic Piping

The vulnerability to slow crack growth, also called brittle-like cracking, of early vintage Aldyl A and other early vintage polyethylene piping materials under certain environmental (such as high ground temperatures), installation, and service conditions has been extensively documented.[98] In 1998, the NTSB issued a special investigation report, *Brittle-Like Cracking in Plastic Pipe for Gas Service*, which concluded that the procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. The report found that much of this early vintage plastic piping may therefore be susceptible to premature brittle-like cracking failures when subjected to stress intensification (NTSB 1998). In response, PHMSA and its predecessor, the Research and Special Programs Administration, issued four advisory bulletins addressing brittle-like cracking in plastic pipe materials.

The 2002 bulletin *Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe* warned that "brittle-like cracking (also known as slow crack growth) can substantially reduce the service life of polyethylene piping systems" (Research and Special Programs Administration 2002). The bulletin specifically cited certain Aldyl A piping material manufactured by DuPont Company before 1973—the same material as the retired Building 2 service tee—as potentially susceptible to brittle-like cracking.[99] A 2007 update to the advisory bulletin added Delrin-insert tapping tees to the list of polyethylene pipe materials susceptible to brittle-like cracking.

District heating systems that use underground steam pipes like the one used by Palmer can be found throughout the United States, particularly in large cities like New York; San Francisco, California; Philadelphia, Pennsylvania; and Denver, Colorado. Of the 68 district heating systems still operating, just over half were built before 1950—with one-quarter built before 1900 (Pierce 2022). The extent of district heating systems nationwide means that other natural gas pipeline operators may have assets near steam pipes. Research has established that elevated temperatures can affect the pressure rating of polyethylene plastic piping, with one study citing the

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[98] These conditions, outlined in a 2002 PHMSA advisory bulletin, include rock impingement, shear and bending stresses from such factors as nearby excavation or frost heave, damaging squeeze-off practices, and installation in areas with higher ground temperatures.

[99] In the 1970s, DuPont found that some Aldyl A pipe samples made between 1970 and 1972 had low-ductile inner wall characteristics resulting from excessive temperature settings during the extrusion process (Haine 2014).

adverse effects of district heating systems on polyethylene gas pipelines (Akhmerova and others 2021).

Early vintage Aldyl A piping is limited to operating conditions below 100°F, and operating outside these conditions increases the risk of slow crack growth. For plastic piping in general, the risk of damage grows as temperatures increase above typical ground temperatures. Modern plastics (including later vintages of Aldyl A) are more resistant to damage at higher temperatures than earlier vintages. Operators base the maximum operating pressure for plastic piping on the properties of the pipe and an assumed maximum environmental temperature; as seen in this accident, the release of steam can raise that temperature, creating an environment in which the piping was not originally designed to operate. To address the risks associated with plastic piping, pipeline operators must be aware of where these assets are located in their system and which ones may be susceptible to slow crack growth or other degradation from outside factors, such as heat. Before the accident, UGI had evaluated the threat and consequences of early vintage Aldyl A to be the same as other polyethylene fittings in its risk models, counter to PHSMA guidance. UGI was not able to conduct a complete inventory of its plastic assets, including manufacturer, with available records. The Palmer steam pipe had not been recorded or identified in UGI's records, precluding UGI from identifying the elevated temperature environment as a threat. The NTSB concludes that because UGI did not have sufficient threat information available for analysis in its DIMP, it could not effectively evaluate and address the risk to pipeline integrity of its plastic piping in elevated temperature environments.

UGI strengthened its data collection and record correction procedures and is working to remediate Aldyl A service tees with Delrin inserts as they are discovered in the field, using new operational procedures and electrofusion repair fittings developed specifically for the tees. UGI is also conducting a complete analysis of all its assets that may be exposed to elevated temperature environments to evaluate and address this threat to pipeline integrity, but this effort needs to be completed. Therefore, the NTSB recommends that UGI inventory all its plastic natural gas assets that may be located in elevated temperature environments and address the risk associated with these assets.

The NTSB is concerned that the extent of the use of plastic natural gas assets throughout the country, including Aldyl A, and their susceptibility to degradation in elevated temperature environments raise the risk of an accident like this one. This accident demonstrates the need to quantify the extent of plastic piping assets in natural gas pipeline systems that are at risk of exposure to elevated temperatures. Historical asset records on pipe installed more than 40 years ago may not be accurate, possibly complicating operators' efforts to assess the extent of plastic piping throughout their systems, as UGI experienced. A 2014 study of natural gas pipeline operators in California demonstrated uncertainty similar to UGI's regarding the extent of the operators' Aldyl A assets (Haine 2014). The NTSB concludes that given the widespread adoption of plastic piping, including Aldyl A assets, and the unreliability of historical asset records, operators may not be aware of the locations of their plastic natural gas assets that are vulnerable to degradation in elevated temperature environments, thus appropriate mitigations may not be in place.

Specific guidance from PHMSA on identifying and evaluating the risks associated with plastic piping in elevated temperature environments would reduce the chances of a similar accident occurring in the future. Once pipeline operators have identified the extent of the threat in their systems, they can evaluate risks and implement mitigations where necessary. Therefore, the NTSB recommends that PHMSA issue an advisory bulletin to all regulated natural gas distribution pipeline operators referencing DIMP regulations and encouraging operators to:

- Complete a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures;
- Continue, during maintenance and new construction projects, to identify plastic assets that are in elevated temperature environments; and
- Evaluate and mitigate risks to deter the degradation of these assets.

Although the failure of Aldyl A tees with Delrin inserts is well documented, this is the first accident NTSB has investigated in which thermal degradation of an Aldyl A service tee with Delrin insert resulted in a fracture that released a substantial amount of natural gas and led to an explosion. Less-severe Delrin insert and cap failures have been documented: 2 years after the 2007 PHMSA advisory bulletin, a 2009 Gas Technology Institute report detailed several insert and cap failures in Aldyl A service tees with Delrin inserts (Mamoun, Maupin, and Miller 2009). Further, data reported to the Plastic Pipe Database Committee show that about 20% of failures of Aldyl A fittings manufactured by DuPont and Uponor were likely caused by the tee with the Delrin insert (American Gas Association 2024).

The NTSB acknowledges that most documented cases of insert and cap failures in Aldyl A service tees have resulted in low-volume leaks; however, we believe that these data must be reassessed in light of this accident. Thus, the NTSB concludes that the severity of this accident, combined with the documented history of failure of Aldyl A service tees with Delrin inserts, indicates a risk associated with the continued use of these components.

Although the 2007 PHMSA advisory bulletin noted that Delrin-insert tapping tees were susceptible to slow crack growth, the NTSB believes that operators need to be alerted to the potentially severe consequences of the tees' degradation. The NTSB therefore recommends that PHMSA issue an advisory bulletin that reviews the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, and advises all regulated natural gas distribution pipeline operators to address the risk associated with Aldyl A service tees with Delrin inserts, including replacing or remediating them.

As part of its IM program, before the accident UGI had reviewed records of leaks and failures associated with Aldyl A service tees with Delrin inserts. They concluded that the tees had a history of leakage from the black Delrin caps and noted that these leaks had been found through normal operations and did not result in serious consequences. However, the vulnerability of early vintage Aldyl A materials to slow crack growth indicate that the Delrin caps were not the only material failure risk that UGI's IM program should have considered. Even though a UGI crewmember recalled a Palmer employee telling them about the presence of Palmer's steam pipe in 2021, UGI had neither trained nor instructed field personnel to report unknown private pipelines to its IM program for evaluation as a pipeline integrity threat. The pipe was not exposed and was not documented in UGI records, preventing UGI's IM program from evaluating the potential threat of the steam pipe. The NTSB concludes, therefore, that had UGI developed procedures and training for its field crews to report potential sources of elevated temperatures (such as steam pipes) found in the vicinity of natural gas assets, the threat posed by the steam pipe could have been identified and assessed through UGI's DIMP, and mitigative measures could have been implemented.

Underground steam pipelines are not the only subsurface assets that pose a threat to natural gas systems and to plastic pipes and fittings in general. A 2007 study cited underground high-voltage electric cables as a source of elevated ground temperatures (Palermo, Zhou, and Farnum 2007). The NTSB previously investigated an accident in South Riding, Virginia, in which heat generated by a damaged electrical line caused the natural gas service line to soften, weaken, and leak, allowing gas to migrate into a home, where it ignited and exploded (NTSB 2001). The NTSB is currently investigating a natural gas explosion that destroyed a home and killed two people in Bel Air, Maryland, in August 2024.[100] The preliminary report for the investigation states that the home's plastic gas service line had been installed in a

[100] The preliminary report for this ongoing investigation can be found on its web page (investigation number PLD24LR006).

common trench with the home's electrical cables and was found with a hole on the bottom of the pipe, and the home had experienced an electrical power outage just before the explosion.

The GPTC Guide states that natural gas pipeline operators should consider heat sources as a hazard to plastic gas main and service lines during construction and offers information on evaluating plastic gas main and service line installations near heat sources for possible mitigative measures. In its DIMP guide material, the referenced GPTC Guide does not mention effects on plastic pipes placed near steam lines or otherwise exposed to potentially elevated temperatures. When a hazard is identified, a pipeline operator must collect information and provide the information to its IM program for evaluation, which did not happen when UGI's field crew encountered the steam pipe near its natural gas assets buried under Cherry Street. The NTSB concludes that additional industry guidance highlighting the threat to pipeline integrity of plastic pipeline exposure to elevated temperatures could improve awareness of this threat so that other operators may identify and effectively manage it through their DIMPs. The NTSB therefore recommends that the GPTC develop guidance for natural gas pipeline operators to ensure that their DIMPs appropriately assess and address threats to plastic pipelines posed by nearby assets that may elevate the temperature of the environment near the pipeline.

After the accident, UGI identified which of its customers may have steam systems located near natural gas assets and is analyzing these areas to determine mitigation measures. UGI updated its procedures to augment surveillance and documentation of steam pipelines in field maps and reporting of such assets to engineering staff. UGI also revised its design manual for determining the route of new or replacement gas assets and for considering separation standards for utilities that present a high safety risk, including steam and electric lines.

This accident, and others investigated by the NTSB, highlight the importance of natural gas pipeline operators strengthening their DIMP programs to more effectively address pipeline safety risks before they result in a catastrophic accident. Our investigation of a 2018 natural gas–fueled explosion at a residence in Dallas, Texas, found that the natural gas pipeline operator had neither adequately considered nor mitigated against threats degrading its pipeline system, the likelihood of failure associated with these threats, or the potential consequences of such a failure in its IM program (NTSB 2021). Therefore, the NTSB recommended that PHMSA

> evaluate industry's implementation of the gas distribution pipeline integrity management requirements and develop updated guidance for improving their effectiveness. The evaluation should specifically

consider factors that may increase the likelihood of failure such as age, increase the overall risk (including factors that simultaneously increase the likelihood and consequence of failure), and limit the effectiveness of leak management programs. (P-21-2)[101]

Of note, in 2023, PHMSA issued a notice of proposed rulemaking (NPRM) that, among other things, would require operators to identify and minimize the risks to their systems from specific threats in their DIMP plans (for example, the presence of certain materials, age, overpressurization of low-pressure systems, and extreme weather and other geohazards).[102] The NTSB supported the NPRM. As of the date of this report, PHMSA is still developing the guidance language for improving the effectiveness of pipeline IM program requirements. The final rule will need to be reviewed to determine if NTSB Safety Recommendation P-21-2 has been satisfied. A final rule is scheduled to be published in 2025.[103]

UGI had developed a DIMP, which was reviewed yearly by the PA PUC. However, as stated earlier, UGI's DIMP had not identified the need to address the threat posed by subsurface assets. The NTSB thus concludes that by not addressing the threat posed by the steam pipe, UGI's DIMP was not effective in preventing the accident. Thus, the current accident again illustrates the importance of strengthening DIMP requirements throughout the natural gas pipeline industry. Therefore, the NTSB reiterates Safety Recommendation P-21-2 to PHMSA.

## 2.4 Unmarked Private Assets in Public Rights-of-Way

Pennsylvania's Underground Utility Line Protection Law requires owners and operators of underground lines serving one or more customers to register with PA

[101] Safety Recommendation P-21-2 is currently classified Open—Acceptable Response.

[102] The NPRM, "Pipeline Safety: Gas Pipeline Leak Detection and Repair," can be found at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair. In August 2024, API released RP 1187, "Pipeline Integrity Management of Landslide Hazards."

[103] The unified agenda for this rulemaking can be found at https://www.regulations.gov/docket/PHMSA-2021-0039/unified-agenda.

One Call (PA One Call 2024).[104] Based on the definitions within Amended Pennsylvania Act 287, the Underground Utility Line Protection Law, Pennsylvania did not require Palmer to be a member of PA One Call.

The Common Ground Alliance's (CGA) *Best Practices Guide* contains a uniform pavement marking color code, which Pennsylvania used. The code includes steam pipelines along with other potentially dangerous materials transported by pipeline such as gas, oil, petroleum, or gaseous materials. The guide recommends marking the location of underground steam pipes with yellow pavement paint. The CGA guide further explains in Best Practice 3-32 that owners and operators of private assets who are not members of an 811 center like PA One Call will not be notified of a planned excavation, and the center will not locate their assets.

Had Palmer's privately owned steam pipelines been registered with PA One Call, these assets would have been identified and marked with a uniform pavement marking as recommended by CGA. Pavement markings indicating the location of Palmer's steam pipelines as well as UGI assets would have been the best practice to alert anyone excavating near the steam pipe of its presence before they began digging.

Palmer's condensate pipe, chocolate pipes, and steam pipe underneath Cherry Street crossed a public right-of-way.[105] Public rights-of-way are subject to excavation not only for utility work, but also for building construction and road work. The entities that perform this work can include utility companies, private contractors, and homeowners. The NTSB concludes that the omission from PA One Call of certain assets transporting high-temperature materials like steam that are located in a public right-of-way can pose a risk to anyone excavating in the vicinity. Damage to these unmarked assets can also damage and degrade nearby assets. Therefore, the NTSB recommends that the Commonwealth of Pennsylvania modify its Underground Utility Line Protection Law to require all owners and operators of pipelines transporting

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[104] The law, Title 73 P.S. Section 176 et. Seq., defines as a "line" or "facility" "underground conductor or underground pipe or structure used in providing electric or communication service, or an underground pipe used in carrying, gathering, transporting, or providing natural or artificial gas, petroleum, propane, oil, or petroleum and production products, sewage, or water or other service to one or more transportation carriers, consumers, or customers thereto." The definition of "line" or "facility" further includes "unexposed storm drainage and traffic loops that are not clearly visible" and "oil and gas well production and gathering lines." The term "facility owner" does not include, among other listed things, a person serving the person's own property through the person's own line, if the person does not provide service to any other customer.

[105] The steam pipe and Palmer's other pipes are no longer in use after the explosion.

steam or other high-temperature materials located in public rights-of-way to register their assets with PA One Call.

The best practices presented in CGA's Best Practice Guide contain both practice statements and practice descriptions, which together provide greater detail to assist with implementation of the practices. Best Practice 3-26 offers clear guidance on who should be members of an 811 center: an entity transporting products or services for consumption or use by means of an underground facility, or for its own use by means of an underground facility in or crossing a right-of-way or utility easement. Although the guidance is clear, the NTSB is concerned that states other than Pennsylvania may also lack requirements for pipelines transporting steam to register with their 811 centers. With stakeholder groups encompassing excavators, gas distribution and transmission companies, state regulators, and more, CGA is well-positioned to conduct outreach on its best practices for 811 center membership. Thus, the NTSB concludes that broad nationwide adoption of CGA's recommended Best Practice 3-26 on 811 center membership can help prevent accidents similar to this one by increasing awareness of underground private assets, like some steam pipes, that cross public rights-of-way. Therefore, the NTSB recommends that CGA identify and pursue opportunities for improving adoption of its best practices on 811 center membership, including updating its best practices guide and encouraging states to adopt the updated guidelines.

## 2.5 Public Awareness and Preparedness

Education and awareness about natural gas are critical to help organizations understand the risk to their facilities and employees and to motivate them to implement policies, procedures, and training to mitigate risks associated with natural gas hazards. For this reason, federal regulations adopted by state pipeline regulators require natural gas pipeline operators to comply with public awareness program standards outlined in API RP 1162, the first edition of which was released in 2003 and is incorporated by reference into the regulations. API RP 1162 is now in its third edition. One of the objectives of such programs is to educate the affected public on how to recognize and respond to a pipeline emergency. As described in the first edition of API RP 1162, the affected public includes people living in single- and multifamily residences as well as "places of congregation" such as businesses or schools with natural gas service.

API RP 1162's baseline communication requirement for the affected public is twice-annual bill stuffers, and these were part of UGI's public awareness program. However, business mail that includes the gas bill and stuffers often is directed to a dedicated department at an organization (such as accounting) and not always seen by all employees. UGI also communicated safety messages through other channels, such as television, radio, newspaper, and social media, as well as community events like baseball games. Like bill stuffers, most of these are one-way communications from UGI with no guarantee that their customers received the information or paid attention to it.

The NTSB has investigated accidents in which ineffective aspects of operators' public awareness programs have led to a lack of public understanding of natural gas hazards. In 2013, we investigated the explosion of a public housing apartment in Birmingham, Alabama, when natural gas in the apartment ignited (NTSB 2016). We found that residents had smelled gas as far back as 2 weeks before the explosion but had not informed the gas company or local authorities; after the accident, the pipeline operator bolstered its dissemination of natural gas safety information to its customers. In our investigation of a 2014 apartment building explosion in New York City, we found that the operator's public awareness programs "did not effectively inform customers and the public about both the importance of reporting a gas odor and the number to call to report a gas odor" (NTSB 2015). The NTSB's investigation of a 2010 natural gas transmission pipeline rupture in San Bruno, California, found that the Pacific Gas and Electric utility company had not corrected a deficient public awareness program that had left the affected public alarmingly unaware of pipeline safety or even pipeline proximity (NTSB 2011).

In interviews with the NTSB after the accident, Palmer management could not recall receiving natural gas safety information from UGI through any means, and they told the NTSB that they believed that their West Reading facilities were at low risk for a natural gas explosion and that employees would have time to react to a leak. Palmer management based this assessment on the minimal natural gas usage in Buildings 1 and 2. However, as demonstrated in this accident and others, any gas leak is dangerous, no matter how minimal the gas usage may be. The underestimation of the danger associated with natural gas leaks indicates that Palmer management had not been adequately informed about these risks.

Effectiveness data on UGI's public awareness program gathered before the accident showed that about one-third of respondents described themselves as either "not too informed" or "not at all informed" about pipelines in their community; a separate survey indicated only about one-third of the affected public who responded had read some or all of UGI's natural gas safety brochure. The data on UGI's public awareness program effectiveness, along with Palmer's deficient understanding of the risks associated with natural gas leaks, indicate room for improvement. The NTSB is concerned that the communications sent by natural gas pipeline operators to their customers in businesses or places of congregation do not adequately inform those who do not directly receive gas bills of natural gas safety. The NTSB thus concludes that natural gas pipeline operator public awareness programs may not reach members of the public in places of congregation or in multifamily residential buildings who do not directly receive bill stuffers; thus, these members of the public may be unaware of the natural gas safety guidance to immediately report a natural gas odor.

After the accident, UGI modified its public awareness program, revising its public communications on "what to do if you smell gas" and developing a new natural gas safety campaign with expanded Spanish-language communications. UGI also has implemented a public awareness pilot program, meeting with and distributing natural gas safety awareness communications kits to their commercial and industrial customers. UGI reported that the additional outreach was well received and that many customers requested additional kits. The NTSB remains concerned that other natural gas distribution pipeline operators may have the same communications issues that UGI previously had with businesses such as Palmer. Effective safety communications are techniques that have proven to be successful in engaging relevant populations—that is, people who live, work, or congregate within the coverage area of a pipeline system—and in ensuring that these audiences receive and understand the safety message. The customer engagement with UGI's postaccident public awareness pilot program indicates effective safety communication with its customers and that operators have ample room and ability to improve upon their communications about natural gas safety. Therefore, the NTSB recommends that PHMSA identify effective means for natural gas distribution pipeline operators to communicate with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system and implement a plan to help operators drive continuous improvement in public awareness of natural gas safety. The NTSB further recommends that API review the findings and plan from PHMSA's actions on P-25-3 and update its RP 1162 to provide specific guidance to natural gas distribution pipeline operators on effective safety communication with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system.

### 2.5.1 Natural Gas Alarms

Public awareness is an effective tool to encourage adoption of safety devices like natural gas alarms. The first edition of API RP 1162 requires that public awareness programs include safety messages about the awareness of hazards and prevention measures as well as leak recognition and response but does not specifically require these programs to disseminate safety messages about natural gas alarms. UGI's public awareness materials distributed before the accident were consistent with federal regulations, and although the materials promoted the use of smoke and carbon monoxide alarms, they did not address natural gas alarms. Following the accident, UGI now includes safety messages encouraging the purchase of natural gas alarms in its public awareness materials. The NTSB concludes that installing natural gas alarms can alert people of a gas leak so they can evacuate the area; however, natural gas customers may not be aware of the necessity of such alarms.

The NTSB believes that messages about the benefits of natural gas alarms are critically important and could save lives when natural gas alarms are installed. The NTSB further believes that the natural gas industry can help shape the effectiveness of public awareness program delivery methods so that people in businesses, schools, residences, and other places of congregation are better informed, both about natural gas hazards and the necessity of natural gas alarms. The American Gas Association, which represents natural gas pipeline operators throughout the US, can facilitate industry efforts to improve public awareness program delivery methods and to improve safety, most critically through increasing the installation of natural gas alarms. Therefore, the NTSB recommends that the American Gas Association share the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, with its members, encouraging them to evaluate the effectiveness of their current delivery methods of public awareness programs and to promote the installation of natural gas alarms in businesses, residences, and other places of congregation that they serve.

Evacuation should occur immediately upon detection of the presence of natural gas. In 1976, the NTSB made its first recommendation to require natural gas detection to provide early warning of leaks.[106] Most recently, after a 2016 building explosion in Silver Spring, Maryland, and then again after the 2018 home explosion in Dallas, we made recommendations to the ICC and the NFPA to require natural gas alarms with methane detection in residences (NTSB 2019).[107] We recommended the ICC work with the Gas Technology Institute and NFPA to

[106] As a result of its investigation of an April 22, 1974, natural gas explosion in a commercial building in New York City, the NTSB recommended that the US Department of Housing and Urban Development advance guidelines for the installation of gas detection instruments in buildings. The recommendation was classified Closed—Acceptable Action in 1985 based on the lack of practical and affordable technology at the time.

[107] Over the years the NTSB has referred variously to these systems as methane detectors; methane detection systems; and, as in this report, natural gas alarms.

Incorporate provisions in the International Fuel Gas Code that requires methane detection systems for all types of residential occupancies with gas service. At a minimum, the provisions should cover the installation, maintenance, placement of the detectors, and testing requirements. (P-19-6)[108]

We made a similar recommendation to the NFPA:

In coordination with the Gas Technology Institute and the International Code Council, revise the National Fuel Gas Code, National Fire Protection Association 54 to require methane detection systems for all types of residential occupancies with gas service. At a minimum, the provisions should cover the installation, maintenance, placement of the detectors, and testing requirements. (P-19-7)[109]

Continuous monitoring systems such as a natural gas alarm can provide early warning of a gas leak and can warn people to evacuate well before natural gas ignites.[110] An alarm offers a clear signal that there is an unsafe or emergency condition and, particularly in a workplace environment in which fire drills are a familiar practice, tells employees what they must do—evacuate. In the case of this accident, an alarm would have made it clear to Palmer employees that an emergency existed.

Palmer's evacuation procedures at the time of the accident directed employees to leave the building when a fire alarm sounded. Considering the absence of natural gas emergency procedures at Palmer, had the company installed natural gas alarms before the accident, the sound of the alarm would have warned Palmer employees to evacuate before the explosion. Further, for those who were worried that evacuating would compromise their employment, an alarm would give them the reassurance they were doing the right thing. Therefore, the NTSB concludes that had natural gas alarms been installed inside Buildings 1 and 2, an alarm could have alerted employees to the natural gas leak, likely prompting them to evacuate,

[108] NTSB Safety Recommendation P-19-6 is classified Open—Unacceptable Response based on pending adoption of provisions requiring methane detection systems in residences into the IFGC.

[109] NTSB Safety Recommendation P-19-7 is classified Open—Acceptable Alternate Response based on the pending incorporation of NFPA 715 into NFPA 54 or other appropriate code.

[110] Although it was not the case in this accident, odorant can be stripped from natural gas in certain situations. The NTSB investigation of the Dallas explosion found that the soil had absorbed and depleted the natural gas odorant, eliminating the opportunity for occupants to detect it.

reducing or eliminating the fatal consequences of the explosion. Following the accident, Palmer did install natural gas alarms.

Recognizing the safety benefits of natural gas alarms in building evacuation and emergency response, some pipeline operators have begun to install natural gas alarms in buildings with natural gas service (Leon 2022). In 2020, the ICC reported that the NFPA was developing NFPA 715, "Standard for the Installation of Fuel Gases Detection and Warning Equipment." The standard was issued in 2022 and covers the "selection, design, application, installation, location, performance, inspection, testing, and maintenance of fuel gas detection and warning equipment in buildings and structures" (NFPA 2023). Like all standards, NFPA 715 offers detailed technical criteria that can be used to meet a code, however, it has not yet been incorporated into NFPA 54. The NTSB believes that NFPA 715 is a comprehensive standard that could be incorporated by reference into the fuel gas codes. Therefore, the NTSB recommends that the ICC revise the IFGC to provide for required installation of natural gas alarms that meet the specifications of NFPA 715 for buildings that use natural gas. The NTSB likewise recommends that the NFPA revise NFPA 54 (the National Fuel Gas Code) to provide for required installation of natural gas alarms that meet the specifications of NFPA 715 for buildings that use natural gas.

Although some states incorporate NFPA and ICC codes into their laws by reference, states vary in which codes they adopt, enforcement mechanisms, and general laws pertaining to the use of natural gas and natural gas alarms in buildings where people congregate.[111] The NTSB concludes that because adoption of codes and other rules related to natural gas alarms depends on state and local policies, widespread requirement of natural gas alarms will depend on state and local action. Therefore, the NTSB recommends that 50 states, the Commonwealth of Puerto Rico, and the District of Columbia require the installation of natural gas alarms that meet the specifications of NFPA 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak. The NTSB has investigated accidents in which a natural gas leak caused an explosion after the gas migrated from the site of the leak to the site of the explosion, from home explosions in Annandale, Virginia, and Bowie, Maryland, in the 1970s, to South Jordan, Utah, in 2024 (NTSB 1972, NTSB 1974).[112]

[111] *Buildings where people congregate* include schools, workplaces, and recreational facilities.

[112] In the Annandale and Bowie accidents, the explosions occurred about 240 feet and 110 feet away from the leaks, respectively. In the South Jordan accident (PLD25FR001), subsurface gas extended about 250 feet from the leak.

## 2.5.2 Companies' Emergency Response Procedures

As a private company, Palmer is regulated by OSHA under its authority to set health and safety standards for private-sector employers. Emergencies can be either natural or manmade, and some can be anticipated and planned for. Emergency response procedures can reduce serious injury or loss of life. OSHA does not have an occupational safety and health standard requiring natural gas emergency response procedures, however. During its postaccident inspection of the March 24 incident, OSHA issued several citations to Palmer. None of the regulations cited would have required the company to have an emergency response plan that addresses natural gas hazards.

According to the American Gas Association, about 5.6 million businesses receive natural gas service. As with Palmer, businesses with natural gas service are not required by OSHA to have an emergency response procedure for a gas leak or related training for employees. Palmers' Red Book had no procedures that addressed natural gas emergencies. Palmer had consulted federal and state agency guidance as well as the NFPA when developing the Red Book. The Red Book addressed other procedures and safety measures required by OSHA—for example, evacuation routes and documentation of fatalities and serious injuries—so it is likely that the company would have included natural gas emergency response procedures had these been required.

As seen in this accident, companies may not recognize a natural gas leak as a serious hazard that needs to be addressed in their emergency response procedures. There are no requirements for natural gas emergency response procedures in the IFGC, which Pennsylvania has adopted. A federal requirement mandating workplace natural gas emergency response procedures could prevent a similar accident to the one in this report. The NTSB concludes that when businesses that use natural gas do not have natural gas emergency procedures and training, employees may be unaware or unsure of the steps they should take if they smell natural gas, thus placing them at risk should a leak occur. With no OSHA regulation specifically requiring an emergency response procedure for natural gas leaks, companies lack official direction on how to protect their workers from natural gas hazards in their buildings. Therefore, the NTSB recommends that OSHA require employers whose facilities use natural gas to implement natural gas emergency procedures. After the accident, Palmer developed natural gas emergency response procedures and workplace safety trainings in both English and Spanish, addressing the safety issue of delayed evacuation during a natural gas leak.

An emergency response procedure can prepare building occupants to respond if a natural gas leak occurs or if a natural gas alarm sounds. Neither of the fuel gas codes—the IFGC, which Pennsylvania has adopted, and NFPA 54, which other states have adopted—contain requirements for natural gas emergency response procedures. The IFC (the fire code adopted by Pennsylvania) requires a fire safety and evacuation plan, but it is not specific to natural gas; similarly, the NFPA fire code (NFPA 1) also does not contain a natural gas–specific emergency procedure.

Model codes like the IFC, IFGC, NFPA 1, and NFPA 54 incorporate consensus standards to protect against hazardous conditions. The code development process is participatory and transparent, establishing broadly accepted code requirements that are adapted and adopted by state and local jurisdictions. The NTSB thus concludes that the consensus-based nature and wide reach of the model codes, such as building or fire codes, make them effective instruments to address natural gas–related risks to employees of businesses that use natural gas. Although these codes may include the fuel gas codes IFGC and NFPA 54, other codes such as the fire codes may be appropriate locations for natural gas emergency response procedures. As noted earlier, the ICC administers the IFC and IFGC. Therefore, the NTSB recommends that the ICC revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures. The NTSB likewise recommends that the NFPA revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures.

## 2.6 Valve Accessibility

During a natural gas emergency such as an explosion or fire, valves along the gas distribution lines are operated to shut off the flow of gas, assisting gas technicians and local emergency responders who are at the scene. Gas continuing to flow into the system can delay emergency response operations and place responders at risk of injury from an ongoing gas fire or secondary explosion.

During the emergency response, the UGI mechanic followed company procedures for closing valves to isolate the natural gas system, working with UGI supervisors to determine which valves to close and other steps to isolate the system. As is typical during the response to an accident involving gas distribution systems, the UGI mechanic attempted to close the valves closest to the accident; these were all secondary valves. Pipeline operators often choose to close the valves closest to the leak to limit the impacted area and reduce the time it takes to burn off the remaining gas in the affected area.

After the UGI mechanic closed the first valve about 5:30 p.m., he encountered difficulty locating the next valve necessary to shut off the rest of the gas flow. The mechanic found a valve with a gas cover in the area, but the valve itself had no plastic tag with a valve number. In July 2024, UGI excavated the site at the NTSB's request and discovered that the correct gas valve had been paved over, and the mechanic had likely been looking at a nearby water valve. Because the UGI mechanic could not positively identify this valve as the correct one, he moved on to two other valves to fully isolate the system. The second of these valves (at South 4th Avenue and Penn Avenue) was not accessible until dirt and debris in the valve box was removed, so it was not closed until 6:15 p.m. Although this valve was designated as a secondary valve, it had been inspected by UGI about 12 months before the accident, and according to UGI's records, the valve box was cleaned at that time. Nonetheless, dirt and debris had accumulated again and delayed isolation of the gas distribution system.

The NTSB reviewed a 2018 image of South 2nd Avenue and Penn Avenue, in which a pair of water valves (valves A and B) are visible but not the gas valve, which was found to be paved over when UGI excavated the valve in 2024. UGI's valve maintenance procedures include 5-year inspections for secondary valves, indicating that UGI would have attempted to inspect this valve while it was paved over, including its most recent documented inspection on March 23, 2021. However, there is no evidence that UGI was aware that the valve had been paved over. In communications with the NTSB, UGI pointed out that the presence of water valve A, which had a gas cover, and suggested that UGI inspectors may have inspected the wrong valve, since both operate in a similar manner. The NTSB has not identified evidence that contradicts this theory, but it was not possible to determine definitively why the paved-over valve was not identified during the 2021 inspection (or previous inspections). The inaccessibility of the paved-over valve and the debris within another valve, both of which were relevant to the emergency response, demonstrates that deficiencies in UGI's valve maintenance program reduced UGI's ability to quickly isolate its system following a leak. The NTSB concludes that UGI did not effectively inspect and maintain its valves through its valve maintenance program, leading to a delay in shutting off gas to the affected area.

After the accident, UGI requested that West Reading Borough make sure water valves were marked with appropriate covers. UGI has also implemented an enhanced valve maintenance program including the use of marker balls to support proper valve identification. The NTSB believes that this effort will improve UGI's valve maintenance program by better equipping UGI inspectors to confirm valve locations.

In this accident, the most expedient valves to access to shut off the gas were secondary valves, and the critical valves (subject to a more-frequent inspection schedule) were not used. The GPTC Guide suggests factors for a natural gas pipeline operator to consider when designating what UGI referred to as critical valves (those defined by 49 *CFR* 192.747 as valves necessary for the safe operation of a distribution system, also known in the industry as operating or emergency valves) on high-pressure distribution lines. These include the total number and type of customers, particularly hospitals, schools, and commercial or industrial users that would be affected by outage or emergency; the number of valves necessary to isolate the area; and the time required for available personnel to isolate the system. The NTSB reviewed UGI's criteria for designating its critical valves, and although the criteria considered the number of customers between critical valves, the criteria made no reference to whether UGI also considered the type of customer or an estimate of the time required to isolate the system. Therefore, the NTSB concludes that because customers vary significantly in the number of occupants or residents, criteria for designating emergency valves that only count customers may not accurately reflect who could be affected by a natural gas outage or emergency or the severity of the effect.

Federal regulations offer criteria for the installation of distribution valves, and GPTC offers guidance for consideration of valve locations, including those necessary for the safe operation of a distribution system, or what UGI called critical valves. The regulations give natural gas operators discretion within those parameters to determine the best location of their valves. As a state-certified program, the PA PUC evaluates each operator's implementation of the requirements of 49 *CFR* 192.747 and determines whether the implementation is reasonable and will result in an effective isolation plan. Therefore, the NTSB recommends that the PA PUC assess the methodology used by natural gas pipeline operators to determine where emergency valves should be located to ensure the operators are properly considering consequences and emergency response times as well as population sizes.

## 2.7 Withholding Safety-Related Information from the NTSB

PHMSA requires pipeline operators to evaluate risks from all threats to the pipeline system integrity through their DIMPs. In our investigation of the March 24, 2023, explosion, the NTSB sought information on the PA PUC's observations and oversight of UGI, requesting DIMP inspection reports from the PA PUC in June 2023. During inspections, the PA PUC collects and analyzes data on an operator's DIMP and determines if the program complies with pipeline safety regulations; this information is then documented in inspection reports. The PA PUC declined to produce the reports, citing state security information nondisclosure laws that support withholding information from "members of the public" and treating the NTSB as a member of the public. Therefore, in September 2023, the NTSB removed the PA PUC as a party to the investigation, after which the PA PUC could not participate in information sharing among parties during the investigation. During its time as a party, PA PUC was otherwise responsive to the NTSB and assisted in the investigation. The NTSB then issued a subpoena for the reports; after lengthy legal action, the NTSB was able to obtain the reports from the PA PUC in April 2024.

Federal law authorizes the NTSB to require, by subpoena or otherwise, the production of necessary evidence during an accident investigation.[113] Further, federal regulations allow the NTSB to obtain any information related to an accident under investigation.[114] The PA PUC's inspection records of UGI's DIMP were material to the investigation because they contained information on UGI's knowledge of and compliance with pipeline safety regulations and safety bulletins or notifications from PHMSA or other agencies. The NTSB thus concludes that the PA PUC's refusal to provide investigative information pursuant to the NTSB's federal authority added to delays in the investigation and safety recommendations. The NTSB recognizes Pennsylvania's concern about the security of pipeline information and the ramifications of potential disclosure. However, the NTSB has processes that prevent the release of information that could be harmful to individuals or to the public. Therefore, the NTSB recommends that the Commonwealth of Pennsylvania review its statutes and amend them to clarify that confidential security information disclosure restrictions do not apply to the NTSB when it is conducting an accident investigation.

[113] Title 49 U.S.C. Section 1113.

[114] Title 49 *CFR* 831.13.

# 3 Conclusions

## 3.1 Findings

1. Neither of the following issues were causal to the accident: (1) pipeline overpressurization or (2) local emergency responder actions.
2. Natural gas migrated from the Aldyl A retired service tee through the ground then into the R.M. Palmer Company Building 2 basement, chocolate pipe conduits, and Building 1, and fueled the explosion in the Building 2 basement.
3. The 1982 retired service tee leaked because of degradation caused by exposure to elevated temperatures; more specifically, slow crack growth of the Aldyl A tower shell and thermal decomposition of the Delrin insert.
4. Steam escaping through the crack of the corroded steam pipe significantly elevated the ground temperature at the location of the retired service tee, which accelerated its degradation and ultimately led to its failure.
5. R.M. Palmer Company's lack of awareness of corrosion-induced wall loss on the steam pipe from Building 1 to Building 2 left the steam pipe vulnerable to localized shear and cracking when external loads changed, which led to steam heating the ground near the retired service tee after UGI Corporation's 2021 service tee replacement project.
6. Had R.M. Palmer Company implemented natural gas emergency procedures and trained their employees and managers on them before the accident, the employees and managers could have understood the danger they faced and could have responded by immediately evacuating and moving to a safe location away from both buildings.
7. Because UGI Corporation did not have sufficient threat information available for analysis in its distribution integrity management program, it could not effectively evaluate and address the risk to pipeline integrity of its plastic piping in elevated temperature environments.
8. Given the widespread adoption of plastic piping, including Aldyl A assets, and the unreliability of historical asset records, operators may not be aware of the locations of their plastic natural gas assets that are vulnerable to degradation in elevated temperature environments, thus appropriate mitigations may not be in place.
9. The severity of this accident, combined with the documented history of failure of Aldyl A service tees with Delrin inserts, indicates a risk associated with the continued use of these components.
10. Had UGI Corporation developed procedures and training for its field crews to report potential sources of elevated temperatures (such as steam pipes)

found in the vicinity of natural gas assets, the threat posed by the steam pipe could have been identified and assessed through UGI's distribution integrity management program, and mitigative measures could have been implemented.

11. Additional industry guidance highlighting the threat to pipeline integrity of plastic pipeline exposure to elevated temperatures could improve awareness of this threat so that other operators may identify and effectively manage it through their distribution integrity management programs.
12. By not addressing the threat posed by the steam pipe, UGI Corporation's distribution integrity management program was not effective in preventing the accident.
13. The omission from the Pennsylvania One Call System of certain assets transporting high-temperature materials like steam that are located in a public right-of-way can pose a risk to anyone excavating in the vicinity.
14. Broad nationwide adoption of the Common Ground Alliance's recommended Best Practice 3-26 on 811 center membership can help prevent accidents similar to this one by increasing awareness of underground private assets, like some steam pipes, that cross public rights-of-way.
15. Natural gas pipeline operator public awareness programs may not reach members of the public in places of congregation or in multifamily residential buildings who do not directly receive bill stuffers; thus, these members of the public may be unaware of the natural gas safety guidance to immediately report a natural gas odor.
16. Installing natural gas alarms can alert people of a gas leak so they can evacuate the area; however, natural gas customers may not be aware of the necessity of such alarms.
17. Had natural gas alarms been installed inside Buildings 1 and 2, an alarm could have alerted employees to the natural gas leak, likely prompting them to evacuate, reducing or eliminating the fatal consequences of the explosion.
18. Because adoption of codes and other rules related to natural gas alarms depends on state and local policies, widespread requirement of natural gas alarms will depend on state and local action.
19. When businesses that use natural gas do not have natural gas emergency procedures and training, employees may be unaware or unsure of the steps they should take if they smell natural gas, thus placing them at risk should a leak occur.
20. The consensus-based nature and wide reach of the model codes, such as building or fire codes, make them effective instruments to address natural gas–related risks to employees of businesses that use natural gas.

21. UGI Corporation did not effectively inspect and maintain its valves through its valve maintenance program, leading to a delay in shutting off gas to the affected area.
22. Because customers vary significantly in the number of occupants or residents, criteria for designating emergency valves that only count customers may not accurately reflect who could be affected by a natural gas outage or emergency or the severity of the effect.
23. The Pennsylvania Public Utility Commission's refusal to provide investigative information pursuant to the National Transportation Safety Board's federal authority added to delays in the investigation and safety recommendations.

## 3.2 Probable Cause

The National Transportation Safety Board determines that the probable cause of the explosion was degradation of a retired 1982 Aldyl A polyethylene service tee with a Delrin polyacetal insert that allowed natural gas to leak and migrate underground into the R.M. Palmer Company candy factory buildings, where it was ignited by an unknown source. Contributing to the degradation of the service tee and insert were significantly elevated ground temperatures from steam escaping R.M. Palmer Company's corroded underground steam pipe, located near the service tee, that had been unmarked and cracked. Contributing to the steam pipe crack was soil movement and R.M. Palmer Company's lack of awareness of the pipe's corroded state. Contributing to the natural gas leak was UGI Corporation's lack of awareness of the nearby steam pipe, which led to an incomplete integrity management program evaluation that did not consider or manage the risk posed by the steam pipe. Contributing to the accident's severity was R.M. Palmer Company's insufficient emergency response procedures and training of its employees, who did not understand the hazard and did not evacuate the buildings before the explosion.

# 4 Recommendations

## 4.1 New Recommendations

As a result of this investigation, the National Transportation Safety Board makes the following new safety recommendations.

**To the Pipeline and Hazardous Materials Safety Administration:**

Issue an advisory bulletin to all regulated natural gas distribution pipeline operators referencing distribution integrity management program regulations and encouraging operators to:

- Complete a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures;
- Continue, during maintenance and new construction projects, to identify plastic assets that are in elevated temperature environments; and
- Evaluate and mitigate risks to deter the degradation of these assets. (P-25-1)

Issue an advisory bulletin that reviews the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, and advises all regulated natural gas distribution pipeline operators to address the risk associated with Aldyl A service tees with Delrin inserts, including replacing or remediating them. (P-25-2)

Identify effective means for natural gas distribution pipeline operators to communicate with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system and implement a plan to help operators drive continuous improvement in public awareness of natural gas safety. (P-25-3)

**To the Occupational Safety and Health Administration:**

Require employers whose facilities use natural gas to implement natural gas emergency procedures. (P-25-4)

**To 50 States, the Commonwealth of Puerto Rico, and the District of Columbia:**

Require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak. (P-25-5)

**To the Commonwealth of Pennsylvania:**

Modify your Underground Utility Line Protection Law to require all owners and operators of pipelines transporting steam or other high-temperature materials located in public rights-of-way to register their assets with the Pennsylvania One Call System. (P-25-6)

Review your statutes and amend them to clarify that confidential security information disclosure restrictions do not apply to the National Transportation Safety Board when it is conducting an accident investigation. (P-25-7)

**To the Pennsylvania Public Utility Commission:**

Assess the methodology used by natural gas pipeline operators to determine where emergency valves should be located to ensure the operators are properly considering consequences and emergency response times as well as population sizes. (P-25-8)

**To the American Gas Association:**

Share the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, with your members, encouraging them to evaluate the effectiveness of their current delivery methods of public awareness programs and to promote the installation of natural gas alarms in businesses, residences, and other places of congregation that they serve. (P-25-9)

**To the American Petroleum Institute:**

Review the findings and plan from the Pipeline and Hazardous Materials Safety Administration's actions on P-25-3 and update your Recommended Practice 1162 to provide specific guidance to natural gas distribution pipeline operators on effective safety communication with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system. (P-25-10)

**To the Gas Piping Technology Committee:**

Develop guidance for natural gas pipeline operators to ensure that their distribution integrity management programs appropriately assess and address threats to plastic pipelines posed by nearby assets that may elevate the temperature of the environment near the pipeline. (P-25-11)

**To the Common Ground Alliance:**

Identify and pursue opportunities for improving adoption of your best practices on 811 center membership, including updating your best practices guide and encouraging states to adopt the updated guidelines. (P-25-12)

**To the International Code Council:**

Revise the International Fuel Gas Code to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas. (P-25-13)

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures. (P-25-14)

**To the National Fire Protection Association:**

Revise National Fire Protection Association 54 (the National Fuel Gas Code) to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas. (P-25-15)

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures. (P-25-16)

**To UGI Corporation:**

Inventory all your plastic natural gas assets that may be located in elevated temperature environments and address the risk associated with these assets. (P-25-17)

**To R.M. Palmer Company:**

Revise your natural gas emergency procedure to direct all employees to immediately evacuate upon smelling natural gas odorant and to specify a safe evacuation location. (P-25-18)

## 4.2 Previously Issued Recommendation Reiterated in This Report

The National Transportation Safety Board reiterates the following safety recommendation.

**To the Pipeline and Hazardous Materials Safety Administration:**

> Evaluate industry's implementation of the gas distribution pipeline integrity management requirements and develop updated guidance for improving their effectiveness. The evaluation should specifically consider factors that may increase the likelihood of failure such as age, increase the overall risk (including factors that simultaneously increase the likelihood and consequence of failure), and limit the effectiveness of leak management programs. (P-21-2)

Safety Recommendation P-21-2 is reiterated in section 2.3 of this report.

**BY THE NATIONAL TRANSPORTATION SAFETY BOARD**

JENNIFER L. HOMENDY
Chairman

MICHAEL GRAHAM
Member

ALVIN BROWN
Vice Chairman

THOMAS CHAPMAN
Member

J. TODD INMAN
Member

**Report Date: March 18, 2025**

# Appendixes

## Appendix A: Investigation

The National Transportation Safety Board (NTSB) was notified of this accident on March 25, 2023. An NTSB investigator arrived at the scene on March 25, and the NTSB launched an official investigation on March 28. The NTSB team consisted of an investigator-in-charge, pipeline operations investigators, an emergency response investigator, integrity management investigators, a materials laboratory investigator, a fire investigator, a video recording investigator, a systems safety investigator, and a photograph specialist investigator. The parties to the investigation are the Pipeline and Hazardous Materials Safety Administration, West Reading Fire Department, Pennsylvania State Police, Spring Township Fire Department, West Reading Borough Police, UGI Utilities Inc. (a UGI Corporation subsidiary), and R.M. Palmer Company.

# Appendix B: Consolidated Recommendation Information

Title 49 *United States Code* 1117(b) requires the following information on the recommendations in this report.

For each recommendation—

(1) a brief summary of the Board's collection and analysis of the specific accident investigation information most relevant to the recommendation;

(2) a description of the Board's use of external information, including studies, reports, and experts, other than the findings of a specific accident investigation, if any were used to inform or support the recommendation, including a brief summary of the specific safety benefits and other effects identified by each study, report, or expert; and

(3) a brief summary of any examples of actions taken by regulated entities before the publication of the safety recommendation, to the extent such actions are known to the Board, that were consistent with the recommendation.

**To the Pipeline and Hazardous Materials Safety Administration:**

**P-25-1**

Issue an advisory bulletin to all regulated natural gas distribution pipeline operators referencing distribution integrity management program regulations and encouraging operators to:

- Complete a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures;
- Continue, during maintenance and new construction projects, to identify plastic assets that are in elevated temperature environments; and
- Evaluate and mitigate risks to deter the degradation of these assets.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

**P-25-2**

Issue an advisory bulletin that reviews the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, and advises all regulated natural gas distribution pipeline operators to address the risk associated with Aldyl A service tees with Delrin inserts, including replacing or remediating them.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

**P-25-3**
Identify effective means for natural gas distribution pipeline operators to communicate with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system and implement a plan to help operators drive continuous improvement in public awareness of natural gas safety.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5, Public Awareness and Preparedness. Information supporting (b)(1) can be found on pages 71–73; (b)(2) and (b)(3) are not applicable.

**To the Occupational Safety and Health Administration:**

**P-25-4**
Require employers whose facilities use natural gas to implement natural gas emergency procedures.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.2, Companies' Emergency Response Procedures. Information supporting (b)(1) can be found on pages 77–78; (b)(2) and (b)(3) are not applicable.

**To 50 States, the Commonwealth of Puerto Rico, and the District of Columbia:**

**P-25-5**
Require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.1, Natural Gas Alarms. Information supporting (b)(1) can be found on pages 73–76; (b)(2) and (b)(3) are not applicable.

**To the Commonwealth of Pennsylvania:**

**P-25-6**

Modify your Underground Utility Line Protection Law to require all owners and operators of pipelines transporting steam or other high-temperature materials located in public rights-of-way to register their assets with the Pennsylvania One Call System.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Unmarked Private Assets in Public Rights-of-Way. Information supporting (b)(1) can be found on pages 69–71; (b)(2) and (b)(3) are not applicable.

**P-25-7**

Review your statutes and amend them to clarify that confidential security information disclosure restrictions do not apply to the National Transportation Safety Board when it is conducting an accident investigation.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.7, Withholding Safety-Related Information from the NTSB. Information supporting (b)(1) can be found on pages 80–81; (b)(2) and (b)(3) are not applicable.

**To the Pennsylvania Public Utility Commission:**

**P-25-8**

Assess the methodology used by natural gas pipeline operators to determine where emergency valves should be located to ensure the operators are properly considering consequences and emergency response times as well as population sizes.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.6, Valve Accessibility. Information supporting (b)(1) can be found on pages 78–80; (b)(2) and (b)(3) are not applicable.

**To the American Gas Association:**

**P-25-9**

Share the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, with your members, encouraging them to evaluate the effectiveness of their current delivery methods of public awareness programs and to promote the installation of natural gas alarms in businesses, residences, and other places of congregation that they serve.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5, Public Awareness and Preparedness. Information supporting (b)(1) can be found on pages 71–73; (b)(2) and (b)(3) are not applicable.

**To the American Petroleum Institute:**

**P-25-10**

Review the findings and plan from the Pipeline and Hazardous Materials Safety Administration's actions on P-25-3 and update your Recommended Practice 1162 to provide specific guidance to natural gas distribution pipeline operators on effective safety communication with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5, Public Awareness and Preparedness. Information supporting (b)(1) can be found on pages 71–73; (b)(2) and (b)(3) are not applicable.

**To the Gas Piping Technology Committee:**

**P-25-11**

Develop guidance for natural gas pipeline operators to ensure that their distribution integrity management programs appropriately assess and address threats to plastic pipelines posed by nearby assets that may elevate the temperature of the environment near the pipeline.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

**To the Common Ground Alliance:**

**P-25-12**

Identify and pursue opportunities for improving adoption of your best practices on 811 center membership, including updating your best practices guide and encouraging states to adopt the updated guidelines.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Unmarked Private Assets in Public Rights-of-Way. Information supporting (b)(1) can be found on pages 69–71; (b)(2) and (b)(3) are not applicable.

**To the International Code Council:**

**P-25-13**

Revise the International Fuel Gas Code to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.1, Natural Gas Alarms. Information supporting (b)(1) can be found on pages 73–76; (b)(2) and (b)(3) are not applicable.

**P-25-14**

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.2, Companies' Emergency Response Procedures. Information supporting (b)(1) can be found on pages 77–78; (b)(2) and (b)(3) are not applicable.

**To the National Fire Protection Association:**

**P-25-15**

Revise National Fire Protection Association 54 (the National Fuel Gas Code) to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.1, Natural Gas Alarms. Information supporting (b)(1) can be found on page 115; (b)(2) is not applicable; and (b)(3) is not applicable.

**P-25-16**

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.2, Companies' Emergency Response Procedures. Information supporting (b)(1) can be found on pages 77–78; (b)(2) and (b)(3) are not applicable.

**To UGI Corporation:**

**P-25-17**

Inventory all your plastic natural gas assets that may be located in elevated temperature environments and address the risk associated with these assets.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

**To R.M. Palmer Company:**

**P-25-18**

Revise your natural gas emergency procedure to direct all employees to immediately evacuate upon smelling natural gas odorant and to specify a safe evacuation location.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.2.2, Delayed Evacuation. Information supporting (b)(1) can be found on pages 62–63; (b)(2) and (b)(3) are not applicable.

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The NTSB is an independent federal agency charged by Congress with investigating every civil aviation accident in the United States and significant events in the other modes of transportation–railroad, transit, highway, marine, pipeline, and commercial space. We determine the probable causes of the accidents and events we investigate and issue safety recommendations aimed at preventing future occurrences. In addition, we conduct transportation safety research studies and offer information and other assistance to family members and survivors for each accident or event we investigate. We also serve as the appellate authority for enforcement actions involving aviation and mariner certificates issued by the Federal Aviation Administration (FAA) and US Coast Guard, and we adjudicate appeals of civil penalty actions taken by the FAA.

The NTSB does not assign fault or blame for an accident or incident; rather, as specified by NTSB regulation, "accident/incident investigations are fact-finding proceedings with no formal issues and no adverse parties … and are not conducted for the purpose of determining the rights or liabilities of any person" (Title 49 *Code of Federal Regulations* section 831.4). Assignment of fault or legal liability is not relevant to the NTSB's statutory mission to improve transportation safety by investigating accidents and incidents and issuing safety recommendations. In addition, statutory language prohibits the admission into evidence or use of any part of an NTSB report related to an accident in a civil action for damages resulting from a matter mentioned in the report (Title 49 *United States Code* section 1154(b)).

For more detailed background information on this report, visit the NTSB Case Analysis and Reporting Online (CAROL) website and search for NTSB accident ID PLD23LR002. Recent publications are available in their entirety on the NTSB website. Other information about available publications also may be obtained from the website or by contacting –

**National Transportation Safety Board**
**Records Management Division, CIO-40**
**490 L'Enfant Plaza, SW**
**Washington, DC 20594**
**(800) 877-6799 or (202) 314-6551**

Copies of NTSB publications may be downloaded at no cost from the National Technical Information Service, at the National Technical Reports Library search page, using product number PB2025-100103. For additional assistance, contact–

**National Technical Information Service**
**5301 Shawnee Rd.**
**Alexandria, VA 22312**
**(800) 553-6847 or (703) 605-6000**
**NTIS website**

# 40 Series Gas ERT® Module Replacement

**Jonathan Mueller**
**Itron R&D Engineering Manager**

## Contents

## Introduction

This white paper provides a high level overview of the advantages gained by replacing 40G and 40GB (40 series) gas ERT® modules with 100G Datalogging Fixed Network (DLN) ERT® modules.

## About 40 Series ERT Modules

The 40 series gas ERT module was the foundation of the Itron AMR gas solution. A low-power, (less than 1 milliwatt) radio device, the 40 series ERT module provided cost effective RF reads for mobile and handheld meter reading. Originally introduced in 1991 as the 40G, the model evolved over a 20 year lifespan to the 40GB in 2005, and included improvements in battery life and reliability.

When the first generation 40G was introduced, expectations were to have a useful battery life of about 14.6 years. Through Itron's ongoing battery field monitoring program, our initial battery life calculations were shown to be conservative. Battery data, based on ERT performance, is detailed throughout this report.

Itron's reliability data and life expectancy predictions must be balanced with the specific customer environment. Data proves batteries tend to last longer in colder climates. ERT modules deployed in warmer climates or on indoor meters result in battery life lasting to the lower range of the life expectancy range. ERT modules deployed in colder regions result in battery-life lasting to the higher end of the life expectancy range.

Improvements in the 40 series gas ERT include:

- a change from silver to palladium silver circuit traces in 1999 for improved reliability in humid situations.
- the introduction of a mercury-free tilt tamper sensor in 2003.
- progressively increasing battery capacity improvements throughout the 40 series ERT module production history.

Over the life of the 40 series ERT module, one thing did not change; quality. The 40G ERT module began with a total 20 year electronic and mechanical design life.

The 40GB reached end of new sales on December 31, 2011, over 20 years since its introduction. During its long production run, over 29 million 40G series ERTs shipped from the Waseca MN Itron factory.

## Itron ERT Module Longevity, a 20-Year Design Life

Itron extensively tests all gas ERT modules for system/RF requirements, firmware processes, and mechanical functionality. All modules boast an accuracy of 99.999 percent with that accuracy maintained over the full environmental operating range of the ERT lasting over the 20-year life of the product. An ERT module reliability plan was developed and executed to support the goal for the gas ERT module failure rate not to exceed .5% per year over 20 years.

To better understand ERT module battery life, Itron completed an extensive amount of analysis. The battery is very important component, but the battery is just one component of an ERT module to consider when the decision is made to extend the 40 series ERT module life by replacing the battery.

The 40 series gas ERT mechanical design was tested for 20 years of operation. Itron is confident that the housing, clear cover, shaft and wriggler will function reliably for the intended period of time (20 years). However, UV exposure, hot and cold temperatures, humidity, and time, all have an impact on the integrity of the mechanical parts. Tests substantiate this in 40 series ERT module accelerated life testing.

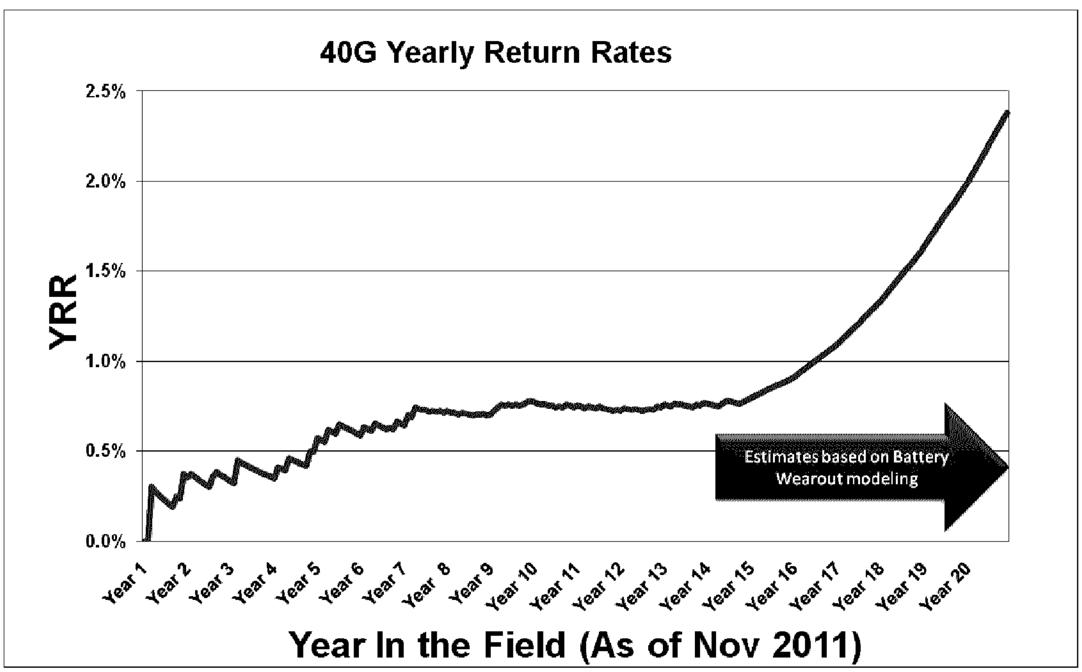
The previously mentioned factors impact other ERT module components:

- Electronic components can begin to leak (consume more electrical current)
- Clear covers can lose transparency.
- Mounting holes in the housing can crack as a result of being under load for many years and exposed to the factors. ERT module removal and re-installation can increase cracking.

The decision to extend the life of the 40 series ERT module should take all factors affecting the product into consideration, not just the life of the battery in the application.

## 40 Series Reliability Field Data

The 40G gas ERT Yearly Return Rates chart show is a return rate based on an Itron-managed customer population of about 200,000 gas ERT modules. Currently, Itron sees about a 0.8% return rate on the ERT module population. Typically, 25% of the returns are not related to product failure bringing the constant failure rate to about 0.6% per year. Almost all the population is over 12 years old. The projection (over the next few years) is based on what we know about battery failure rates during those periods.



## 40G/40GB Replacement Drivers

Although the 40 series is considered to be the proverbial workhorse of the AMR world, Itron recommends the utility give consideration to upgrading to the 100G DLN rather than replacing the battery and returning the 40G/GB ERT to field service.

Reasons to consider upgrading include:

- 40Gs manufactured between 1991 and 2003 employ a mercury switch for tilt detection. While the switch contains a miniscule amount of mercury, retirement from the field and proper disposal reduce the chance that mercury could be released into the environment.
- Modules manufactured before 6/24/99 contain silver substrate circuitry on the ceramic printed circuit board which can be susceptible to failure in a hot, humid environment.
- Battery replacement in a 14 year old ERT results in the projected battery life exceeding the 20 year design life of the module's mechanical and electronic components.
- Field replacement of batteries results in the loss of the Class I, Div I ERT module rating.
- A small percentage of reworked ERTs fail when they are returned to service due strictly to handling. This occurs even with new units.

40 series ERT modules are limited to one index read only.

The following table illustrates feature and functionality differences between the 40G, 40GB, and 100G DLN gas ERT modules.

| Year Introduced | 1991 | 2005 | 2011 |
|---|---|---|---|
| Feature/Function | 40G | 40GB | 100G DLN |
| Bubble Up Mode | | X | X |
| Mobile High Power Mode | | | X |
| Hard to Read Mode | | | X |
| Fixed Network mode | | X[1] | X |
| Datalogging | | | X |
| 20 Year Nominal Battery Life | | X[2] | X[3] |
| 20 Year Design Life | X | X | X |
| Field Replaceable Battery | X | X | X |
| Wave Wriggler | | | X |
| Overmolded Gasket | | | X |
| Mercury-free Tilt Sensor | | X[4] | X |
| Substrate Improvements | X[5] | X | X |

X[1] Low Power Limits Network Effectiveness

X[2] Battery Life = 13 Years in Network Mode

X[3] Battery Life = 15 Years in Hard to Read Mode

X[4] Mercury-free Tilt Sensor Introduced in 2003

X[5] Palladium Silver Substituted for Silver Substrate in 1999

## Benefits of Replacing 40 Series ERT Modules with 100G DLN ERT Modules

While the 100G DLN maintains the fundamental magnet and reed switch design of the 40 series, the 100G DLN offers more efficient mobile reads and an economical migration path to Fixed Network operations.

Increased transmit power allows a Mobile Collector to skip streets along the route and still maintain a read rate similar to that achieved with the 40 series.

Built-in capability for migration to a Fixed Network system allows deployment of the 100G DLN module in bubble-up mode in a mixed environment with 40G series ERTs. The 100G DLN ERT module can be reconfigured in the future to connect to a Fixed Network system. In a Fixed Network, reads can be requested at the time the module bubbles-up allowing collection of same day and move-in/move-out readings. Network communication reduces the need for truck rolls and provides better customer billing accuracy.

Network connectivity also allows near real-time tamper event reporting from the module. This functionality can help in the effective investigation and reduction of energy diversion.

The 100G DLN has data logging capabilities which allows it to store the most recent 40 days of hourly interval data. This makes the 100G DLN gas modules valuable in providing an additional data source to assist in the investigative process following a major incident. The utility can analyze hourly volume data from the gas module as part of the event origin and cause analysis associated with the incident. 100G Datalogging module data availability has already reduced several utilities' exposure to litigation and liability costs.

From a mechanical perspective, the 100G DLN offers a mechanical, electronic, and battery design-life of 20 years. Other significant mechanical improvements over the 40G ERT include:

- long-lasting molded Santoprene gaskets replace cork gaskets
- improved wriggler design on all residential direct mount ERT modules.

100G DLN deployment does not require an FCC license. The 100G DLN operates in bubble-up mode in the unlicensed ISM band.

**Note:** As long as 40 series ERTs are being read in any route, the wake-up signal requires an FCC license. In any mixed system (40G series and 100G DLN ERT modules), the utility must keep the required FCC licenses up-to-date.

## Summary

Consideration should be given to replacing aging 40 series ERT modules with 100G DLN ERT modules since the latter provides increased functionality which will reduce operating expenses and improve efficiencies. Its datalogging functionality, effectively making it a "black box" for incident investigation, has been used by utilities to reduce the "deep pocket" effect commonly encountered following a natural gas related incident.

Utilities should also follow proactive programs in ERT replacement to assure that sudden decreases in meter reading rates are not experienced and should always keep in mind that the design life of the electronics for all 40 and 100 Series ERT modules is a total of 20 years.



**CORPORATE HEADQUARTERS**

2111 N Molter Road
Liberty Lake, WA 99019
USA

**Phone:** 1.800.635.5461
**Fax:** 1.509.891.3355

# SNOW SEASON **SAFETY**

METER WITHOUT SNOW SHELTER

METER WITH SNOW SHELTER

Heavy snow and ice falling from roofs can damage natural gas meters, regulators, and associated natural gas piping. Special care must be taken when clearing roofs to prevent impact. Also, ice and snow accumulation, whether natural or manmade, can damage gas meters and outdoor appliances and create a hazardous leak.

Southwest Gas will immediately suspend service when damage from snow and ice is discovered at a natural gas meter or on customer's receiving piping. Service will be restored once snow and ice are cleared, adequate meter protection is installed, and the customer complies with any requirements imposed by the local jurisdiction.

Southwest Gas reminds you that it's important to maintain and protect natural gas meters and appliances because failure to do so can result in damages and injuries, and possibly the discontinuance of natural gas service.

A leak may be present if you:

**SMELL** a distinct sulfur-like odor similar to rotten eggs, even if it's faint or momentary.

**HEAR** a hissing or roaring coming from the ground, above-ground piping or a natural gas appliance.

**SEE** dirt or water blowing into the air, unexplained dead or dying vegetation or grass or standing water continuously bubbling.

If you ever suspect a gas leak, immediately leave the area and call **911** and **Southwest Gas** immediately at **877-860-6020**.

For more information about natural gas safety, visit **swgas.com/safety** or call **877-860-6020.**

**SOUTHWEST GAS**®

swgas.com

## TIPS TO HELP PROTECT AGAINST POTENTIAL DAMAGE:

Install a structurally engineered shelter above the natural gas meter to prevent snow and ice accumulation.

For more information on how to build a snow shelter or for a contractor referral, please visit Southwest Gas at **swgas.com/snow-safety** or call **877-860-6020**.

- Use a broom, instead of a shovel where possible, to clear snow or ice off natural gas meters and outdoor appliances, including regulators, associated piping, and propane appliances.
- When shoveling, plowing, or using a snow blower, don't pile snow on gas meters or outdoor appliances.
- Keep all outside gutters free of leaves and debris, including those above or near the natural gas meter and outdoor appliances.
- Natural gas appliances require proper exhaust and ventilation. It's important to know the location of air supply and exhaust ducts, and keep them free of snow, ice, leaves or other debris. Keeping vents clear can prevent operational problems for appliances and the accumulation of carbon monoxide in buildings.

# SEGURIDAD PARA LA TEMPORADA DE NIEVE

MEDIDOR SIN PROTECCIÓN PARA NIEVE

MEDIDOR CON PROTECCIÓN PARA NIEVE

La nieve y el hielo pesados que caen de los techos pueden dañar los medidores, los reguladores, y la tubería de gas natural relacionada. Se debe tener cuidado especial cuando se limpien los techos para evitar un impacto. También, la acumulación de nieve y hielo, ya sea natural o artificial, puede dañar los medidores de gas y los aparatos exteriores, y así crear una fuga peligrosa.

Cuando se descubren daños ocasionados por nieve y hielo en un medidor de gas natural o en una tubería de ingreso de gas natural de un cliente, Southwest Gas retira el medidor. Una vez que se elimina la nieve y el hielo y se instala una protección adecuada en el medidor, se restablece el servicio.

Southwest Gas le recuerda que es importante dar mantenimiento y proteger los medidores y aparatos de gas natural porque el no hacerlo puede provocar daños y lesiones, y tal vez el corte del servicio de gas natural.

Puede haber una fuga si usted:

**HUELE** - un olor como azufre, similar a huevos podridos, incluso si es débil o momentáneo.

**ESCUCHA** - un sonido como silbido o un estruendo inusual que provenga del suelo, la tubería sobre el suelo, o un aparato de gas natural.

**VE** - suciedad o agua volando por el aire, vegetación muerta o a punto de morir sin causa aparente, o si ve agua estancada que forma burbujas de forma continua.

Si sospecha que hay una fuga de gas, abandone la área inmediatamente y llame al **911** y a **Southwest Gas** inmediatamente al **877-860-6020**.

Para obtener más información sobre seguridad de gas natural, visite **swgas.com/safety** o llame al **877-860-6020**.

SOUTHWEST GAS®
swgas.com

## HE AQUÍ CONSEJOS PARA AYUDAR A PROTEGERLOS DE UN POSIBLE DAÑO:

Instale una protección sobre el medidor de gas natural para evitar la acumulación de nieve y hielo. Para mayor información sobre cómo construir una protección contra nieve o para obtener referencias sobre un contratista, visite Southwest Gas en **swgas.com/snow-safety** o llame al **877-860-6020**.

- Utilice una escoba, en lugar de una pala cuando sea posible, para limpiar de nieve y hielo los medidores y aparatos exteriores, incluso los reguladores, la tubería relacionada, y los dispositivos a gas propano.
- Cuando esta paliar, arar, o usando una quitanieves, no acumule la nieve sobre los medidores o aparatos exteriores.
- Mantenga todos los desagües exteriores libres de hojas y basura, incluso aquellos sobre o cerca del medidor de gas natural y de los aparatos exteriores.
- Los aparatos de gas natural requieren de una salida y ventilación adecuadas. Es importante que conozca la ubicación de sus ductos de suministro y salida de aire y que los mantenga libres de nieve, hielo, hojas u otros desechos. Mantener los conductos libres puede evitar problemas operativos de los aparatos y la acumulación de monóxido de carbono en los edificios.

**STATE OF NEVADA**

**PUBLIC UTILITIES COMMISSION**



SENT VIA E-MAIL

August 11, 2025

Ms. Jennifer L. Homendy
National Transportation Safety Board
Chairman
490 L'Enfant Plaza, SW,
Washington, DC 20594
Email Response to - ExecutiveSecretariat@ntsb.gov

**Re: April 8, 2025, Letter Regarding UGI Corporation Natural Gas-Fueled Explosion and Fire, West Reading, Pennsylvania, March 24, 2023, NTSB/PIR-25/01 and Safety Recommendation P-25-5**

Dear Ms. Homendy:

On April 8, 2025, a letter was sent to Governor Lombardo, regarding information and recommendations arising from the National Transportation Safety Board's (NTSB) investigation into the UGI Natural Gas Explosion Incident that occurred on March 24, 2023, in West Reading, PA. Governor Lombardo has since forwarded this letter to the Nevada Public Utilities Commission ("PUCN") for a response.

Pipeline safety remains a top priority for Nevada. The State has long recognized the risks associated with Aldyl A natural gas pipelines. In 2011, the PUCN approved an accelerated pipeline replacement program authorizing Nevada's largest natural gas distribution operator, Southwest Gas Corporation, to begin replacing all early-vintage plastic pipes, including all Aldyl A pipe mains and services.

As the graph below illustrates, in 2010, Southwest Gas operated more than 120 miles of Aldyl A pipe mains in Nevada. By the end of 2024, that number had been reduced to fewer than five miles. All remaining Aldyl A pipelines are scheduled for replacement by the end of 2025,[1] at which point there will be no known Aldyl A pipe remaining in active operation within Nevada's natural gas distribution system.

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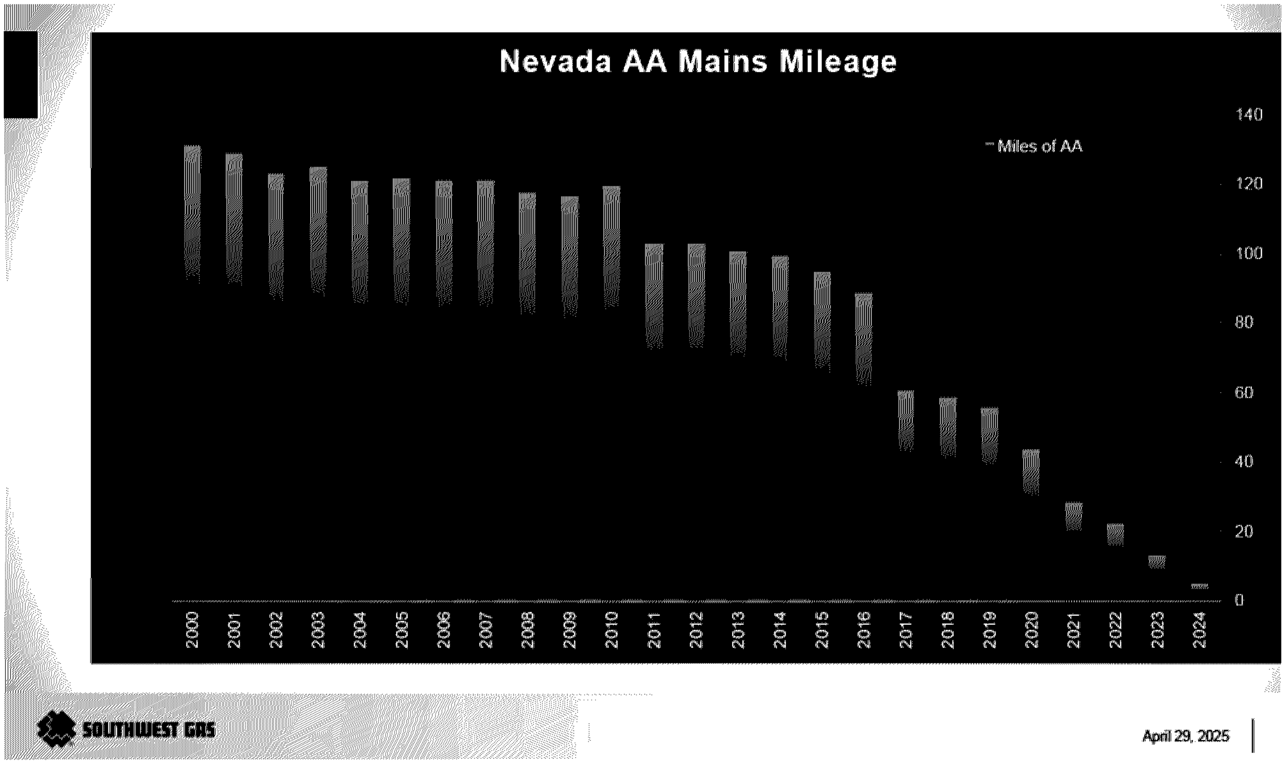
[1] The same applies for Aldyl A pipeline services; these service lines will also be fully replaced by the end of 2025.




In addition to the accelerated pipeline replacement work, in 2021, Nevada became the first state in the nation to adopt an annual natural gas leak detection and survey regulation, significantly advancing pipeline safety. Adopted by the PUCN in Docket No. 19-09011, this regulation mandates that every 49 CFR 192 jurisdictional intrastate natural gas and propane pipeline operating in Nevada be leak-surveyed every year. This requirement applies regardless of pipe type, vintage or age, size, or location. Importantly, the regulation requires the use of an electronic detection instrument for these surveys. Visual inspections alone, such as identifying dead vegetation, are no longer permitted. This state requirement marks a major improvement over the current federal standard in 49 CFR 192.723, which only requires a leak survey every five years.

By increasing the frequency and reliability of leak detection, Nevada's regulation helps to ensure that leaks are identified and addressed more quickly. This improves public safety and efficiency and reduces environmental risk. The benefits of this proactive approach have been presented at numerous regulatory forums. A presentation highlighting these advantages is available on the PUCN's website and can be viewed here: https://www.youtube.com/watch?v=SFMmKdDENYE.

The NTSB also recommended:

"Require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak."

In response, Nevada's key stakeholders, including PUCN Staff, Southwest Gas, and NV Energy (the state's other major utility) have initiated discussions regarding the feasibility of a pilot program. This program would involve installing natural gas detection alarms in select high-occupancy buildings and monitoring the performance of these devices. It is essential that the functionality, reliability, longevity, and public acceptance of the devices be evaluated, along with other key data points, before a statewide mandate for their installation in all new and existing homes and buildings will be considered.

The PUCN greatly values its relationship with the NTSB and sincerely appreciates the thoughtful safety recommendations outlined in your April 8, 2025, letter.

Sincerely,

Stephanie Mullen
Executive Director

Paul Maguire
Manager, Engineering Division

cc: Tim Robb, Director of Strategic Initiatives & Homeland Security Advisor, trobb@gov.nv.gov
Hayley Williamson, PUCN Chair, hwilliamson@puc.nv.gov
Brett D. Compston, Nevada's Emergency Manager/Homeland Security Chief, b.compston@dem.nv.gov
Anne-Marie Cuneo, PUCN Director of Regulatory Operations, amcuneo@puc.nv.gov
Neil Pascual, PUCN Regulatory Engineer & Pipeline Safety Program Manager, npascual@puc.nv.gov)

# Southwest Gas Corporation
# Natural Gas Alarm Pilot Program
# Program Overview (Nevada Only)

## I. Program Purpose

Southwest Gas Corporation ("Southwest Gas" or "Company") proposes a Natural Gas Alarm Pilot Program ("Pilot Program" or "Program") to facilitate the purchase, distribution and installation of natural gas alarms within its Northern Nevada and Southern Nevada service territories to enhance public safety and public awareness. As part of this Pilot Program, the Company will primarily target high occupancy facilities, including schools and community centers, as well as residences in established and/or historically underserved communities (as defined by NRS 704.78343), through a phased deployment strategy to ensure efficient rollout and effective stakeholder engagement.

## II. Background and Justification

As a required safety measure, the natural gas Southwest Gas delivers to its customers is odorized for the public to easily recognize. Natural gas alarms may provide an additional safety measure for early detection of a natural gas leak to help prevent safety incidents, property damage, and potential injuries. In recent years, the National Transportation Safety Board ("NTSB"), regulatory bodies such as the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), and some state public utility commissions[1] have increased focus on natural gas safety measures. Most recently, the NTSB Chair sent letters to the Governor's office of each State iterating the NTSB Recommendation P-25-5 to:

> "…*require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak.*"

The distribution and installation of natural gas alarms into customer homes, businesses, schools, and other high occupancy facilities is consistent with this recommendation and helps improve the safety of people and property.

## III. Program Scope

The Pilot Program will initially target the distribution and installation of natural gas alarms in the following categories[2]:

---

[1] The Pennsylvania Public Utility Commission (Docket No. C-2022-3033834 and New York State Public Service Commission (22-G-0065) have approved natural gas alarm (methane detector) programs. In addition, the California Public Utilities Commission supports methane detection technologies.

[2] While Southwest Gas will actively facilitate communication and coordination throughout the Program, Southwest Gas acknowledges that participation ultimately rest with the customer.

- **Educational Facilities:** (e.g., daycares, pre-schools, K-12 schools, charter schools, universities, community colleges, etc.)
- **Community Centers:** (e.g., YMCA, Boys and Girls Clubs, senior centers, churches, etc.)
- **Residences:** established and/or historically underserved residential communities (as defined by NRS 704.78343) including mobile home parks
- **Other:** (e.g., customer request, combination with other Company initiatives, public awareness outreach, or as identified by Program oversight)

## IV. Goals and Objectives

- Purchase, distribute, and facilitate the installation of up to 10,000 natural gas alarms, within a 3-year period throughout Southwest Gas' Northern and Southern Nevada service territories based on the proportional percentage of Nevada customers, as follows:
  - 87.5% in Southern Nevada (8,750 alarms)
  - 12.5% in Northern Nevada (1,250 alarms)
  - Target Category
    - Educational Facilities
      - Southern Nevada – approximately 400
      - Northern Nevada – approximately 150
    - Community Centers and Churches
      - Southern Nevada – approximately 350
      - Northern Nevada – approximately 250
    - Residences in Established and/or Underserved Communities / Zip Codes
      - Southern Nevada – approximately 4,800
      - Northern Nevada – approximately 700
    - Other Category
      - Southern Nevada – approximately 3,200
      - Northern Nevada – approximately 150

## V. Stakeholder Engagement

A. **Internal:** Create a cross-functional Project team involving departments such as Engineering, Legal, Regulatory Affairs, Customer Engagement, Operations, Safety & Quality, and Corporate Communications.

B. **External:** Engage the necessary and appropriate individuals to facilitate participation in the Pilot Program such as, school leaders, community center property managers or executive directors, external public outreach organization, local governments, state agencies, fire departments, and community organizations.

## VI. Technology Selection

- The DeNova Detect® natural gas alarm (Model: DD620NV), sourced by Heath, has been selected for implementation for this Pilot Program. This alarm has voice alerts in both English and Spanish to announce warnings of a natural gas leak. Other features and benefits include:
  - 10-year battery and product service life
  - Battery-powered alarm mounts close to ceiling where natural gas accumulates first and follows proper alarm placement to meet NFPA 715 guidelines
  - 11 minutes more escape time. The low-level natural gas alarm threshold of 10% LEL[3] alerts to emergencies earlier on average than competitors' higher 25% LEL threshold.
  - Validated by Fire & Risk Alliance
  - Self-diagnostics provide peace of mind by ensuring all internal systems are functional, and alerts will be provided if an error occurs
  - Micro-Electromechanical System (MEMS) sensor technology provides accurate and faster detection of natural gas leaks than traditional type sensors found in plug-in alarm
  - Virtually eliminates false alarms caused by harsh household chemicals, such as laundry detergent, disinfectant spray, aerosol hairspray, furniture polish, among others
  - Validated by GTI testing
  - ETL Listed to UL 1484 Standard

## VII. Distribution Strategy

A. **Educational Facilities:** Coordinate with school facility managers to install alarms in locations such as kitchens, boiler rooms, garages, basements, laundry rooms, science labs, kitchens, boiler rooms, laundry rooms. Schedule installation during off-peak times (e.g., summer break).
B. **Community Centers:** Identify high-use gas zones (e.g., kitchens, HVAC systems, etc.).
C. **Residences in Established and/or Historically Underserved Communities (as defined in NRS 704.78343):** Identify zip codes/communities for established and historically underserved communities (as defined in NRS 704.78343) and partner with

[3] LEL is short for "Lower Explosive Limit", which is defined as the lowest concentration (by percentage) of gas or vapor in the air that is capable of producing a flash of fire in the presence of an ignition source (arc, flame, heat).

housing authorities and property management firms. Offer bulk installation programs and multilingual tenant education. Installation locations could include garages, kitchens, laundry rooms, furnace areas where such equipment or functionality is located.

D. **Other:** Promotion of the Natural Gas Alarm Pilot Program will be on SWGAS.COM and communication materials will be distributed at Public Awareness Events. Nevada customers who are not within the target audience and receive this information can request to have a natural gas alarm installed. By evaluating efficiency and costs, the Company will also explore combining its initiatives with the distribution of natural gas alarms as it aligns with operational activities.

## VIII. Deployment Phases

1. **Planning:**
    - Select the appropriate sites/locations from each category identified above and number of alarms to be distributed per category per the manufacture's installation directions.
        1. Target to identified zip codes/communities
        2. Determine if the distribution and installation of natural gas alarms can be incorporated with Southwest Gas established initiatives
    - Assess baseline gas safety awareness and leak response data
    - Establish contractor and contracts for installation
2. **Initial Deployment:**
    - Roll out to high-occupancy areas (e.g., educational facilities, community centers, etc.)
    - Develop communication materials promoting the Pilot Program and training
3. **Full Pilot Program Implementation:**
    - Deploy to all identified target categories in a phased approach
    - Regularly update stakeholders and adjust plan based on feedback
4. **Monitoring and Optimization:**
    - Track customer calls that were generated due to the natural gas alarm, and if the leak was positive or negative
    - Analyze incident trends and adjust alarm placements as applicable

## IX. Communication and Education Plan

- Create multilingual brochures and digital content for each target group

- Conduct live demos, webinars, and training sessions for residents, staff, and facility managers
- Launch a public awareness campaign through the following media outlets:
  - Social Media Posts
    - Rotating basis between Facebook and Instagram posts. Run posts for 5 days at a time. Anticipating a total of 36 posts per year.
  - Geofencing
    - Providing contextual and location-based geofencing, based off a set list of zip codes, which includes a rotating selection of static ads linked to a web landing page.
  - Technician Tear Sheet
    - Educational tear sheets for customer service technicians to leave behind with customers in both English and Spanish.
  - Digital
    - Includes streaming audio, paid search, NextDoor, display ads across high-traffic sites, and Meta in both English and Spanish.
  - Eblasts
    - Recommend two emails in the year to balance with other quarterly promotional emails. Option to highlight natural gas alarms in biannual safety eblasts as well.
  - Bill Messaging
    - Includes educational messaging monthly to all customers with a bill insert two times in the year.
  - Web Landing Page
    - A dedicated web page that all campaign pieces will drive to. This will be used to measure click-through rates and engagement. It will link to further safety information.
  - On-Hold Messaging
    - Tailor messaging to Nevada residents for customer service calls. Includes professionally recorded scripts to play while callers are waiting.
- Include emergency response training for local fire and EMS teams (include in Liaison training)

## X. Budget and Funding

- Estimated Pilot Program expenditures based on installing 10,000 natural gas alarms is approximately $2.7M during the 3-year Pilot Program. However, as noted in Section XIII, if the program is successful and the installation number of the natural gas alarms increases, so will the estimated dollar amount.
- Establish a regulatory asset account to track the costs of the Pilot Program for recovery in a future general rate case
- The table below shows the estimated expenditures based on 10,000 natural gas alarms:

| Total Nevada Estimated Natural Gas Alarm Costs - 3 Yr. Pilot | | | | | |
|---|---|---|---|---|---|
| Line No. | Description | Year 1 | Year 2 | Year 3 | Total |
| 1 | Est. Total Installation & Alarm Costs | $1,208,333 | $438,333 | $438,333 | $ 2,085,000 |
| 2 | Est. Public Awareness | $ 75,000 | $ 75,000 | $ 75,000 | $ 225,000 |
| 3 | Est. Outreach Costs | $ 140,000 | $140,000 | $140,000 | $ 420,000 |
| 4 | Est. Total 3-Yr. Pilot Program | $1,423,333 | $653,333 | $653,333 | $ 2,730,000 |
| Note: All costs reflected are estimates and variable freight costs are not included. | | | | | |

## XI. Risk Assessment and Mitigation

- **Technical Risks:** Device failures, reliability, and accuracy
- **Legal Risks:** Access and liability issues — obtain informed consent and provide necessary information
- **Community Resistance / Concerns:** Address potential customer concerns and cost perceptions — use community advocates and provide educational information.
- **Human Element:** Removing alarms, ignoring the alarms, and relocating the device

## XII. Metrics and Success Criteria

- Number and percentage of natural gas alarms installed vs planned
- Detection accuracy and number of validated leak alarms
- Track and document the emergency gas leak callouts that were a result of the natural gas alarms
- Stakeholder satisfaction from post-deployment surveys
- After 3 years, survey the customers to see if the natural gas alarms are still installed in the original installation locations and track the data. Document if the natural gas alarm is no longer at the installation location.

## XIII. Regulatory and Compliance Reporting

- Report metrics and progress to Public Utilities Commission of Nevada (PUCN) in the Company's Resource Plan
- Maintain documentation for inspections and audits
- Propose in a future rate case filing to amortize the costs recorded to the regulatory accounts that are related to this program.
- If within this 3-year Pilot Program period the Company successfully deploys at least 9,000 natural gas alarms, the Company is authorized to purchase, distribute and install up to an additional 10,000 natural gas alarms to be distributed consistent with the specifications included in this Program Overview.

## XIV. Continuous Improvement

- To demonstrate transparency and accountability, information and status updates for this Pilot Program will be communicated to the Regulatory Operations Staff of the Public Utilities Commission of Nevada at the Quarterly Technical Meetings beginning in 2027.

# AFFIRMATION OF KEVIN M. LANG

Pursuant to NAC 703.710, Kevin M. Lang affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 15 day of September, 2025

KEVIN M. LANG

Exhibit 4

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY

OF

THOMAS W. CARDIN

ON BEHALF OF

SOUTHWEST GAS CORPORATION

September 17, 2025

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of

Thomas W. Cardin

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Thomas W. Cardin

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Thomas W. Cardin. My business address is 6355 Shatz Street, North Las Vegas, Nevada 89115.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Southern Nevada Division. My title is Vice President/Southern Nevada Division.

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (Commission).

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 The purpose of my prepared direct testimony is to provide an overview of and support for the significant operational or capital requirements that the Company plans to implement in the Southern Nevada rate jurisdiction throughout the action plan period.[1] I also provide support for why each activity is required to provide

[1] As defined in the Commission's Proposed Regulation submitted to the Legislative Counsel Bureau November 25, 2024, "action plan period" means the three-year period immediately following the date on which a resource plan is filed with the Commission.

safe and reliable service to the Company's customers, the estimated cost of construction for each activity, and the annual cost of operation. Finally, I support, from an operations perspective, the continuation of the currently authorized Customer-Owned Yard Line (COYL) Replacement Program and new proposed safety-related programs.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My prepared direct testimony consists of the following key items:

- A discussion on the Company's capital investment project procedural framework and oversight process;
- An overview of the Significant Operational or Capital Requirements included in the Company's Triennial Resource Plan (Resource Plan);
- A discussion of and support for new single line extension facilities required to meet customer growth and serve 2,000 or more customers;
- A discussion of and support for the system integrity projects required to maintain customers' level of service;
- A discussion of and support for pipeline integrity management programs required to maintain compliance with state and federal regulations;
- A discussion of and support for the continuation of the COYL Replacement Program;
- Support for the development and implementation of a 1984/1985 (84/85) Pipe Replacement Program in Southern Nevada; and
- Implementation of the Company's proposed Natural Gas Alarm Pilot Program in Southern Nevada;

## II. CAPITAL INVESTMENT PROJECT PROCEDURAL FRAMEWORK AND OVERSIGHT PROCESS

**Q. 7 Please describe the procedural framework and oversight process applicable to Southern Nevada capital investments.**

A. 7 The procedural framework for Southern Nevada capital investment projects consists of controls, processes, and procedures for anticipating, identifying, managing and mitigating the variability in capital projects. To ensure a robust capital investment process, various departments with diverse areas of expertise are involved in the identification and execution of Southern Nevada capital projects. In addition, overarching key components of transparency of controls, accountability of responsibilities, a project evaluation program, and project risk management process are implemented to ensure oversight and quality. The Nevada capital budget goes through an extensive, iterative review process with senior management and ultimately. the final capital budget as proposed, is presented to the Company's Board of Directors for final approval.

**Q. 8 What is the general process for capital investment projects in Southern Nevada?**

A. 8 To coordinate the processes that strengthen project outcomes, Southern Nevada uses a capital procedural framework composed of up to six project lifecycle phases and multiple project elements. Depending on the complexity and size of a project, some or all of the phases and elements may be used. The project lifecycle is planning, design, construction, completion, acceptance, and operations and maintenance. Project elements that support the project lifecycle are project organization framework, procurement and contracts, project scope and change management, costs, schedules, systems and tools, issue management, communication and reporting, quality, and safety.

Southern Nevada utilizes definitions of responsibilities and reporting hierarchy, so there is accountability in the execution of the project. This is accomplished through use of the Company's policies, procedures, best practices and guidelines, reporting dashboards and reports, and training for the correct use of policies and procedures. This clarity helps the organization manage capital projects more efficiently by avoiding gaps. Key stakeholders include personnel from the following departments: Safety Quality Training Qualifications; Engineering Services; System Integrity; Regulatory and Compliance; Supply Chain; Internal Audit; Risk Management; Purchasing; and Legal.

Southern Nevada also uses a project risk management process to monitor risks and identify when a mitigation plan is needed to manage risks. The project risk management process allows for the ability to recognize and respond to the early signs of project deviations, such as budgets, construction schedules, project scope changes, material delays, quality and safety concerns, damage prevention, design revisions, contract change orders, and other deviations. These situations signal when it is necessary for management to investigate and gather the key stakeholders to discuss causes and solutions.

After a capital project is completed, Southern Nevada evaluates the project to determine efficiencies and effectiveness. This project evaluation benefits capital projects in several ways by: (1) identifying opportunities to improve policies, procedures, and controls; (2) preventing deviations from policies, procedures, and controls; (3) identifying higher risk activities requiring management focus; (4) recognizing opportunities for cost reduction, avoidance, or recovery activities; and (5) providing opportunities to examine lessons learned and provide actionable recommendations for continuous improvement for existing and future projects.

**Q. 9 Please explain how the cost estimates for the projects discussed in your testimony were developed.**

A. 9 The estimated costs for the projects discussed in my testimony are based on historical costs for similar work with certain adjustments or considerations based upon current construction activity. The actual costs incurred will be impacted by many factors, both known and unknown. A new known factor is that, in 2025, the Nevada Legislature passed Senate Bill 443 which requires the payment of prevailing wages for construction work awarded to a contractor for the replacement of a natural gas pipeline approved in a plan submitted pursuant to NRS 704.991. Southwest Gas does not know with certainty how that requirement will impact the costs of applicable projects as the Company does not have the historical wage rates of the Company's contractors' employees, so it is unable to estimate how the prevailing wage requirement will ultimately impact overall costs.

## III. OVERVIEW OF SIGNIFICANT OPERATIONAL OR CAPITAL REQUIREMENTS INCLUDED IN THE RESOURCE PLAN

**Q. 10 Please describe what qualifies as Significant Operational or Capital Requirement pursuant to a resource plan.**

A. 10 As defined in Senate Bill (SB) 281, Significant Operational or Capital Requirements means the construction of a new transmission, distribution, compression or storage facility or the rehabilitation, replacement, modification, upgrade, uprate or update of existing facilities, or any planned series of such activities addressing the same need, in which the anticipated cost exceeds the threshold established by the Commission pursuant to subsection 3 of Nevada Revised Statutes (NRS) 704.991. The Commission's proposed regulations[2] have

[2] On July 25,2023, the Commission opened a rulemaking, designated as Docket No. 23-07024, to amend, adopt, and/or repeal regulations in accordance with SB 281 (2023). The Commission's proposed regulation, drafted in accordance with SB281, was submitted to the Legislative Counsel Bureau November 25, 2024,

established a $5 million threshold for Significant Operational or Capital Requirements, as well as three additional qualifying activities including, in summary: (1) construction of a single extension facility with 2,000 or more new customers or with a forecasted maximum annual load over the next five years that is greater than two percent of the gas utility's forecasted load during the first year; (2) any long-term arrangement resulting from a gas utility's request for incremental upstream resources that requires an interstate pipeline to receive approval from the Federal Energy Regulatory Commission (FERC); and (3) investment in infrastructure that facilitates the introduction of nongeologic gas into the gas utility's system.

**Q. 11 Has the Company included significant operational or capital requirements, as defined, in its Resource Plan that are anticipated in Southern Nevada during the action plan period?**

A. 11 Yes. The Company has construction-related capital expenditure projects currently underway, and planned, in Southern Nevada that are estimated to exceed the established $5 million threshold during the action plan period, including new single extension facilities required to serve 2,000 or more new customers. In this Application, the Company is not proposing investment in infrastructure that facilitates the introduction of nongeologic gas into its Southern Nevada system.

**Q. 12 Please provide an overview of the construction-related Significant Operational or Capital Requirements for Southern Nevada that are currently underway and planned during the action plan period?**

A. 12 Southern Nevada has multiple Significant Operational or Capital Requirements that are underway, and planned, for the next three years. Below, I have compiled the projects that qualify as Significant Operational or Capital Requirements into 4 categories:

- New Single Extension Facilities Projects;

- System Integrity Projects;
- Distribution Integrity Management Program (DIMP) Projects; and
- Transmission Integrity Management Program (TRIMP) Projects;

I discuss the planned projects for each of these categories below.

**Q. 13 Are there other projects or programs that you discuss below?**

A. 13 Yes, in addition to the Significant Operational or Capital Requirements projects underway or planned, my testimony also discusses the Company's proposal to continue the COYL Replacement Program and the implementation of the following two new programs in Southern Nevada:

- 84/85 Pipe Replacement Program; and
- Natural Gas Alarm Pilot Program.

## <u>IV. NEW SINGLE EXTENSION FACILITIES PROJECTS</u>

**Q. 14 Please provide an overview of how the Company evaluates the configuration for high-pressure distribution facilities.**

A. 14 Southern Nevada integrates future system requirements and operational efficiency considerations with current system demands by conducting a hydraulic gas model (model) for the addition of high-pressure distribution facilities. The model is optimized, and simulated gas networks predict operational capabilities and address operational challenges, such as overall system flows and pressures. The results provide Southern Nevada with the decision support for planning and design, which assists with future system operations and maintenance while considering current system needs.

**Q. 15 What high-pressure distribution projects is Southern Nevada currently undertaking that will continue during the action plan period?**

A. 15 There are two high-pressure distribution projects designed to serve more than 2,000 customers that Southern Nevada currently underway that will continue during the action plan period – the Tule Springs Project and the Summerlin West

Project.

**Tule Springs Project**

**Q. 16 Please describe the Tule Springs Project.**

A. 16 The Tule Springs Project is a residential and commercial master planned development located in North Las Vegas, Nevada and estimated, at full build-out, to serve approximately 10,000 homes east of Revere Street and the Bruce Woodberry Beltway (Interstate 215). As discussed in my prepared direct testimony in the Company's most recent general rate case[3], given the project was located in an undeveloped area that lacked gas infrastructure, the project required the installation of 16-inch high-pressure distribution main, 4-inch and 6-inch polyethene (PE) distribution main and a regulator station, which supplies gas to PE distribution mains and service lines. These facilities will deliver natural gas to the homes and commercial buildings that are built in and near the development. Southwest Gas has been constructing the Tule Springs Project since 2022. The estimated completion for the full build-out of Southwest Gas' facilities at the Tule Springs Project is 2028.

**Q. 17 Why is the Tule Springs Project necessary?**

A. 17 The Tule Springs Project is necessary to meet demand and customer growth and ensure safe and reliable service to customers. Based on the new master planned community's connected gas load, the existing Southern Nevada distribution system did not have existing facilities in the location nor sufficient system capacity to serve the project. If the development were added without a high-pressure distribution approach main, then the existing system pressure would decrease and result in the loss of service to new and current customers, and likely unpredictable outages in the future. Planning studies were conducted and

[3] Docket No. 23-09012 at page 18.

determined that the Tule Springs Project required 3 miles of high-pressure 6-inch steel distribution approach main to serve the project.

**Q. 18 Why is a 16-inch high-pressure distribution main required?**

A. 18 In 2015, Southern Nevada developed the transmission and feeder strategy (TAFS) plan, which is a long-term strategic plan. The TAFS plan integrates key considerations and generates a model of a future concept of the Company's Southern Nevada transmission and high-pressure distribution systems. The TAFS plan incorporates growth, adaptation to changing conditions, and operational efficiencies, such as increasing pipe size at the time of installation and avoiding future costly pipeline reinforcements. It is a roadmap for how the Company will manage and develop infrastructure addressing areas like safety, reliability, and growth. Consistent with the TAFS plan, the Company identified the Tule Springs Project as an opportunity to install a 16-inch high-pressure distribution pipe, which will connect with an existing bridge crossing located near Interstate 215 and Losee Road and the new Lamb Tap facilities high-pressure reinforcement project in North Las Vegas, Nevada. The 16-inch high-pressure distribution main will allow the Company to serve current and anticipated future load in the area without the need for a pipeline reinforcement or future upsizing of the pipeline.

**Q. 19 Is the forecasted maximum annual load over the next five years for the Tule Springs Project greater than 2 percent of the Company's forecasted load in the first year following the filing of the Resource Plan contemplated in this docket?**

A. 19 As discussed in the prepared direct testimony of Company witness Carla D. Ayala, the forecasted load for this project is not greater than 2 percent of the Company's forecasted load.

**Q. 20 What is the estimated total cost of the Tule Springs Project during the action plan period?**

A. 20 The total estimated cost of the Tule Springs Project during the action plan period is $10.5 million, with approximately $3.5 million per year. The recently completed phase was $1.6 million.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Tule Springs Project | $3,500,000 | $3,500,000 | $3,500,000 | $10,500,000 |

**Summerlin West Project**

**Q. 21 Please describe the Summerlin West Project.**

A. 21 The Summerlin West Project is a residential master planned development located in Las Vegas, Nevada and estimated to serve several thousand homes west of Sky Vista between Alta Drive and Lake Mead Boulevard. The project is contiguous to the Company's existing infrastructure and is located within its certificated service area, however, the undeveloped area lacks gas infrastructure. Given the lack of gas infrastructure, the project required the construction of high-pressure distribution main and a regulator station, which will supply gas to low-pressure distribution mains and service lines.

**Q. 22 Why is the Summerlin West Project necessary?**

A. 22 The Summerlin West Project is necessary to meet demand and customer growth and ensure safe and reliable service to customers. Based on the master planned community's connected gas load, the existing Southern Nevada distribution pipe system did not have existing facilities or sufficient system capacity to serve the project. If the development were added without a high-pressure distribution approach main, then the existing system pressure would decrease and result in the loss of service to new and current customers and likely unpredictable outages in the future. Planning studies were conducted and determined that the

Summerlin West Project required an 8-inch steel distribution high-pressure approach main to serve the area.

**Q. 23 Is the forecasted maximum annual load over the next five years for the Summerlin West Project greater than 2 percent of the Company's forecasted load in the first year following the filing of the Resource Plan contemplated in this docket?**

A. 23 As discussed in the prepared direct testimony of Company witness Carla D. Ayala, the forecasted load for this project is not greater than 2 percent of the Company's forecasted load.

**Q. 24 What is the estimated total cost of the Summerlin West Project?**

A. 24 The estimated total cost of the Summerlin West Project is approximately $8 million during the action plan period. The recently completed phase of the Summerlin West Project was approximately $2.8 million and was recently placed in service.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Summerlin West Project | $2,666,667 | $2,666,666 | $2,666,666 | $8,000,000 |

**Q. 25 Please provide a summary of the estimated cost of New Single Facilities Extension Projects planned during the action plan period.**

A. 25 The table below summarizes the estimated costs of the New Single Facilities Extension Projects underway during the action plan period.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Tule Springs Project | $3,500,000 | $3,500,000 | $3,500,000 | $10,500,000 |
| Summerlin West Project | $2,666,667 | $2,666,666 | $2,666,666 | $8,000,000 |
| Total New Single Extension Facilities Projects | $6,166,667 | $6,166,667 | $6,166,667 | $18,500,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the New Single Extension Facilities Projects in his prepared direct testimony.

**Q. 26 Does the Company anticipate any incremental operating costs related to the New Single Extension Facilities discussed above?**

A. 26 The Company anticipates a negligible amount of incremental operating costs, such as those related to annual leak survey, related to the new Company-owned facilities resulting from the Tule Springs and Summerlin West Projects.

## V. SYSTEM INTEGRITY PROJECTS

**Q. 27 What is a system integrity project?**

A. 27 A system integrity project is undertaken to ensure the Company's system continues to provide safe, reliable and resilient service to its customers and may contemplate a variety of facilities, including, but not limited to, mains, services, meters, regulator stations and related appurtenances. Southern Nevada is actively managing the construction of two system integrity projects currently underway: the Lamp Tap Project and the Grand Teton Project. Both the Lamb Tap Project and the Grand Teton Project are discussed in more detail below.

In addition to those projects, the Company has also planned two additional system integrity projects: the Southern Transmission System "L" Line Integrity Management Replacement Project and an Encoder Receiver Transmitter (ERT) Project to replace the current aging population of 40G ERTS with new AMR-type ERT devices to ensure the integrity of the Company's customer billing. The prepared direct testimony of Company witness Kevin M. Lang supports and discusses the ERT Project. Both of these projects are discussed in more detail below.

**Lamb Tap Project**

**Q. 28 Please provide an overview of the Lamb Tap Project.**

A. 28 As described in the Company's most recent Annual Resource Planning Informational Report[4], Southwest Gas forecasted a need for a new interconnect with Kern River Pipeline in the Northeast area of North Las Vegas. The project, now referred to as the Lamb Tap Project, includes several miles of steel transmission pipeline that will connect to the Company's existing high-pressure system and is needed to serve projected extreme weather demands starting in the 2025/2026 heating season. The Lamb Tap Project is currently underway.

**Q. 29 Why is the Lamb Tap high-pressure system integrity project necessary?**

A. 29 The Company completed a supply requirement study and concluded that a new source of supply was needed to ensure continued operations of a safe and reliable system, and to support continued growth (residential, commercial and industrial) in the northeast area of the Las Vegas valley. The Lamb Tap Project is needed to meet the projected customer demand that will exceed the current system capacity. Company witness Carla D. Ayala supports and discusses the Company's forecasting methodology in her prepared direct testimony.

**Q. 30 What tap sites currently serve the northern portion of the Las Vegas valley?**

A. 30 The Company's Southern Nevada system has two existing tap sites located in the northwest and the northern central portion of the Las Vegas valley as shown in Appendix F of the Resource Plan, sheet Appendix F-1. The Lone Mountain Tap was constructed in 1993, and the Centennial Tap was constructed in 2002. Both tap sites are nearing their maximum capacity. The Pecos Tap is also located in the northern portion of the Las Vegas valley and it will be decommissioned after Lamb Tap is placed into service.

[4] Docket No. 24-06034

**Q. 31 Why is a 24-inch high-pressure distribution pipeline required?**

A. 31 The Lamb Tap Project consists of two interconnections on Kern River, a new pressure limiting station, an in-line inspection launcher and receiver, approximately three-miles of 24-inch diameter high-pressure pipeline, and supporting facilities located in the northeast area of North Las Vegas. Consistent with the TAFS plan, the three-mile 24-inch high-pressure transmission pipeline will improve system reliability by establishing a connection with an existing 16-inch high-pressure pipeline located near the vicinity of east Craig Road and north Lamb Boulevard in North Las Vegas as shown in Appendix F of the Resource Plan, sheet Appendix F-2). The connection to the existing 16-inch high-pressure pipeline will enable the Lamb Tap Project to increase pressure on the existing high-pressure pipelines from 300-psig to 720-psig as shown in bold orange in Appendix F of the Resource Plan, sheet Appendix F-2.

**Q. 32 How does the Lamb Tap Project provide redundancy to the Southern Nevada system?**

A. 32 Once the Lamp Tap Project is complete and placed in service, it will support the two existing tap sites that are near maximum – Lone Mountain Tap and Centennial Tap – located in the northwest and northeast areas of the Las Vegas Valley. The connection to the to the existing 16-inch high-pressure pipeline will allow the Lamb Tap Project to provide the system reinforcement and redundancy necessary to serve the northern and eastern parts of the Las Vegas Valley.

**Q. 33 What is the estimated total cost and in-service date of the Lamb Tap Project?**

A. 33 The estimated total cost of the Lamb Tap Project is approximately $29 million, of which approximately $8.6 million has been incurred to date. The anticipated completion date of the Lamp Tap Project is October 2026.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Lamb Tap Project | $20,400,000 | $0 | $0 | $20,400,000 |

**Q. 34 Does the Company anticipate any incremental operating costs related to the Lamp Tab Project discussed above?**

A. 34 The Company estimates approximately $95,000 per year in incremental operating costs after the Lamp Tap Project has been commissioned. Further, the transmission pipeline contemplated as part of the project will require inline inspections every seven years which currently cost approximately $300,000.

<u>Grand Teton Project</u>

**Q. 35 Please describe the Grand Teton Project.**

A. 35 Consistent with the TAFS plan, the Grand Teton Project presented an opportunity to install a 16-inch high-pressure distribution pipe on a new City of Las Vegas bridge at Veterans Memorial Highway (US 95) and West Grand Teton Drive. The Company has an existing Kern River mainline tap (Lone Mountain Tap), which supports the northwest area of Las Vegas. There is a high-pressure system located east of US 95 and a high-pressure system located west of US 95 as shown in Appendix F of the Resource Plan, sheet Appendix F-3. Also shown in Appendix F of the Resource Plan, sheet Appendix F-4, is the connection of the two high-pressure systems with the Grand Teton Project which provides system reinforcement and improves flow capacity while increasing reliability and enhancing the integrity of the Company's Southern Nevada system.

**Q. 36 Why is a 16-inch high-pressure distribution approach required?**

A. 36 The City of Las Vegas bridge at Veterans Memorial Highway (US 95) and West Grand Teton Drive was structurally designed for the 16-inch pipeline. Future upsizing of the high-pressure pipeline installed on an existing bridge is complex and, if constructed in the future, would likely be entirely prohibitive due to limited access, structural integrity concerns, and higher costs of construction. Installing the 16-inch high-pressure pipeline in the Grand Teton Bridge offered benefits by simplifying complex crossings, reducing construction impacts, and lowering overall construction costs. It also allows for a more established corridor for the pipeline. By elevating the pipeline above ground, bridge crossings can protect it from potential damage and the need for extensive ground disturbance by way of a technically complex horizontal directional drilling process under a major highway.

**Q. 37 What is the estimated total cost of the Grand Teton Project?**

A. 37 The installation of the 16-inch high pressure pipeline in the Grand Teton Bridge in 2025 has an estimated total cost of $2.5 million. There are two 16-inch high pressure projects scheduled in 2027 that will connect the Grand Teton project to existing high-pressure pipelines located east and west of US-95 at Grand Teton Drive. The estimated total cost for the remainder of the work for the Grand Teton Project is $2.5M.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Grand Teton Project | $0 | $2,500,000 | $0 | $2,500,000 |

**Q. 38 Does the Company anticipate any incremental operating costs related to the Grand Teton Project discussed above?**

A. 38 The Company anticipates a negligible amount of incremental operating costs, such as those related to annual leak survey, related to the new Company-owned facilities resulting from the Grand Teton Project.

**Southern Transmission System (STS) Replacement Projects**

**Q. 39 Please provide an overview of the STS.**

A. 39 STS infrastructure was constructed prior to the implementation of the Code of Federal Regulations (CFR) Part 192 in 1970, which covers federal safety standards for the transportation of natural gas. The STS consists of two early-vintage steel[5] pipelines totaling nearly 140-miles that were initially installed in 1956 and 1963 with multiple pipeline sizes and operating pressures. These pipelines are designated as the "L" and "R". STS was the original feed for natural gas into Las Vegas and has been augmented multiple times over the past 60 years. STS was the sole feed for natural gas into Las Vegas until 1991.

**Q. 40 Please provide an operational overview of the Company's STS.**

A. 40 Natural gas is transported to the Company's southern Nevada STS facilities from Southwest Gas Transmission Company (SGTC). SGTC transports natural gas supplies received from its interconnection with El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern) to its downstream interconnection with the Company at the Arizona-Nevada boundary located in the middle of the Colorado River near the southern limits of Bullhead City, Arizona. This location is about 9 miles north of the SGTC metering station. The Company's 720 pounds per square inch gauge (psig) Maximum Allowable Operating Pressure (MAOP) system proceeds northwesterly for about 4 miles to Intersection Point. At connection point between Southwest Gas pipelines and the SGTC pipeline (called Intersection Point), natural gas supplies received from the incoming SGTC pipeline branch into three Southwest Gas-owned pipelines, one having an MAOP of 720 psig and the other two having MAOPs of 500 psig. One 500 psig MAOP pipeline from the Intersection Point transports gas supply north

[5] Nevada Administrative Code 704.7962 defines early-vintage steel pipe as any natural gas pipeline composed of steel which was installed in a natural gas system before January 1, 1971.

to a distribution system serving Laughlin, Nevada. The other 500 psig MAOP ("L" Line) pipeline and the 720 psig MAOP ("R" Line) pipeline proceed north through Eldorado Valley to the Las Vegas valley.

The STS also includes a compressor station called the Davis Dam Compressor Station. The Davis Dam Compressor Station consists of two compressor units, associated monitoring and control facilities, and station piping from each of the Company's three high-pressure mains at that location. The Davis Dam Compressor Station piping divides into two different high-pressure systems, each of which connects to one of two separate compressor units. Each compressor unit consists of a centrifugal gas compressor driven by a natural gas-fired combustion turbine unit. A 1,100 HP Saturn turbine drives one compressor, and a 3,730 HP Centaur turbine drives the other compressor. The compressors operate independently, with the Centaur unit operating on the 720 psig MAOP piping and the Saturn unit designed to operate on either the 720 psig MAOP system or the 500 psig MAOP system.

North of the compressor station, the two 500 psig MAOP transmission mains merge to a single main at the Davis Dam Crossover. North of that point, the 500 psig MAOP transmission main and the 720 psig MAOP transmission main intersect at several crossover points. Valves at such crossover points provide for alternative paths of natural gas flow in the event of an outage in any one section of the transmission system.

North of the Davis Dam Crossover, the 500 psig MAOP and 720 psig MAOP mains proceed to the Searchlight Crossover #1, where the 720 psig MAOP transmission main terminates. From Searchlight, the mains proceed north as one 500 psig MAOP transmission main and one 650 psig MAOP transmission main, to the Powerline Crossover. The same two mains proceed north toward Las

Vegas. Farther north at the Substation Crossover, an additional 720 psig MAOP main joins the two lines into the Las Vegas area.

**Q. 41 Please describe how the STS connects to the Company's distribution system serving Southern Nevada.**

A. 41 The southern supply system connects to distribution system in the Las Vegas valley through a network of transmission and high-pressure distribution pipelines, having MAOPs of 120 psig to 720 psig. Natural gas enters this network from the southern transmission pipeline facilities at four separate gate stations. Two of these stations are located at the Wigwam Pressure Limiting Station (PLS) located in the southeast part of the Las Vegas valley. Both stations connect to the 720 psig MAOP main extending from the Blue Diamond Tap (discussed below). The third gate station is the Horizon Ridge PLS located at the far southeast end of the Las Vegas valley, which is where the 500 psig MAOP and 650 psig MAOP STS mains connect with the southern supply system. The fourth gate station is the Clark PLS, which is in the southeast part of the Las Vegas valley and connected to the 650 psig MAOP southern transmission main. Please refer to Appendix F, of the Resource Plan, sheet Appendix F-1, for a map.

**Q 42 What Significant Operational or Capital Requirements is Southwest Gas planning with respect to the STS?**

A 42 The Company has one planned replacement project for the STS, the STS "L" Line Integrity Management Replacement Project, during the action plan period. In addition, the Company is also planning on another project called the STS Replacement Project, however that project is not planned for the action plan period. Both of those projects are discussed below.

**Q 43 If the STS Replacement Project is not planned for the action plan period, why are you providing a discussion?**

A 43 Providing a description of the STS Replacement Project in this testimony helps describe the long-term plan for the STS system and provide additional context for the benefits of the STS "L" Line Integrity Management Replacement Project.

**<u>STS "L" Line Integrity Management Replacement</u>**

**Q. 44 Please provide an overview of MAOP Reconfirmation process.**

A. 44 The safety of gas transmission pipeline rule is a set of regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to enhance the safety of natural gas transmission pipelines. The regulations aim to reduce the frequency and consequences of failures and incidents by improving early detection of threats. The rule requires operators to reconfirm that the MAOP of transmission pipelines located in class 3 locations are traceable, verifiable, and complete. Southwest Gas witness Kevin M. Lang provides additional information as to the applicability of this process to transmission lines in his prepared direct testimony.

**Q. 45 Please provide an overview of the STS "L" Line Integrity Management Replacement Project.**

A. 45 The "L" Line Integrity Management Replacement Project will replace approximately three miles of 16-inch vintage steel pipeline (VSP) with a 24-inch pipeline from the Horizon Ridge PLS heading south on Dutchman Pass Road as shown in Appendix F of the Resource Plan, sheet Appendix F-5.

**Q. 46 Why is the STS "L" Line Integrity Management Replacement necessary?**

A. 46 As noted above, PHMSA requires operators of gas transmission pipelines to reconfirm the MAOP of certain pipeline segments. This requirement aims to improve pipeline safety by ensuring that pipelines operate within safe pressure limits. The PHMSA Mega Rule requires that pipeline segments within class 3 locations meet the records requirement for traceable, verifiable, and complete (TVC) requirements to establish MAOP.

The “L” line is VSP that was installed in 1956 and the Company identified approximately one-half mile of pipeline that does not meet the criteria for TVC and requires remediation pursuant to the MAOP reconfirmation prior to July 3, 2028. The remaining 2.5-miles of “L” line that will be replaced as part of the “L” Line Integrity Management Replacement project was identified for replacement because sections of the pipeline are exposed and also have the potential for outside force damage. PHMSA safety regulations address areas susceptible to outside force damage. The regulations require operators to identify, assess, and mitigate potential threats like earth movement, seismicity, and other geotechnical hazards. The Company proposes to take measures to prevent damage and minimize the consequences of outside forces. Burying pipelines improves safety and reliability and shields the pipeline from damage caused by human activities, vehicles, weather events like floods, and temperature extremes. The “L” line has 16 separate exposed spans totaling approximately 1,350 feet. In addition to preventing damage and minimizing the consequences of outside forces, replacement of the entire 2.5-mile section instead of just a span of specific locations, reduces the potential for galvanic corrosion.

**Q. 47 Please explain the issue of galvanic corrosion.**

A. 47 When different metals are in contact with each other, an electrochemical reaction can occur. The less noble metal in the connection acts as the anode, losing electrons and corroding more rapidly, while the more noble metal acts as the cathode. This process accelerates the corrosion process. As there are 32 connections, the likelihood of corrosion would be high when connecting older pipelines, such as the “L” Line, to new pipelines, and the replacement of the entire 2.5 miles seeks to minimize this result.

**Q. 48 What is the estimated total cost of the STS L-Line Integrity Management Replacement Project?**

A. 48 The estimated total cost of the STS L-Line Integrity Management Project is $8.5 million and is currently budgeted for 2027 to ensure completion by the required date of July 3, 2028.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| STS L-Line Integrity Management Replacement Project | $0 | $8,500,000 | $0 | $8,500,000 |

**Q. 49 Does the Company anticipate any incremental operating costs related to the STS L-Line Integrity Management Replacement Project discussed above?**

A. 49 No, the Company does not anticipate an increase in operating costs related to the STS L-Line Integrity Management Replacement Project but does anticipate efficiencies gained and a negligible reduction in operating costs.

**<u>STS Replacement Project</u>**

**Q. 50 Is the STS Replacement Project a Significant Operational or Capital Requirements for Southern Nevada for the action plan period?**

A. 50 Not at this time. As discussed above, the STS Replacement Project is considered for a period beyond the action plan period. The following description is to provide additional context for the benefits of the STS "L" Line Integrity Management Replacement Project.

**Q. 51 Please describe the future state of the STS.**

A. 51 The Company plans to install a single nearly 70-mile 24-inch diameter steel pipeline within an existing permanent right-of-way and Bureau of Land Management grant. The STS Replacement Project may be constructed in three separate phases with Phase 1 constructed outside of the action plan period but within the next five years. Two additional phases are expected following Phase 1 over the following five to ten years as shown in Appendix F of the Resource

Plan, sheet Appendix F-6. Phase 1 of construction would start south of Searchlight and end at the Eldorado Tap and contemplate the installation of approximately 27-miles of 24-inch steel pipeline. During Phase 1, the Company would abandon the existing 27-miles of the "R" pipeline and approximately 67-miles of the existing "L" pipeline between Intersection Point and the Horizon Ridge PLS. As contemplated, the STS Replacement Project would eliminate nearly 97-miles of the pre-code 1956 and 1963 VSP.

**Q. 52 Is the STS necessary to provide reliable and resilient service to customers?**

A. 52 Yes. The Company's STS accounts for more than 20% of the required gas supplies during an extreme weather event. Approximately 80% of the Southern Nevada demand is supplied from existing tap sites in the Las Vegas area due to its geographical location on the system as shown in Appendix F of the Resource Plan, sheet Appendix F-1. The current Las Vegas tap sites and the Lamb Tap Project discussed above are unable to meet customer demand without gas supply provided from the STS during an extreme weather event. The prepared direct testimony of Company witness Laura Spurlock provides discussion on the value of alternative supplies from several interstate pipelines flowing through the STS and how those supplies provide optionality to Southern Nevada's natural gas supply which helps ensure reliable service to the Company's Southern Nevada sales customers.

**Q. 53 What are the benefits of the STS Replacement Project?**

A. 53 As noted above, supplies received on the STS account for more than 20% of the required gas supplies during an extreme weather event and the STS provides optionality and access to supplies on Transwestern and El Paso that allows the Company to avoid being captive on just a single source of supply. The STS Replacement Project would ensure that those benefits continue by eliminating almost 97-miles of the pre-code 1956 and 1963 VSP and replacing that pipe with new steel pipeline that is installed with current construction techniques. Company witness Kevin M. Lang provides additional information as to the safety and reliability concerns previously expressed about VSP in his prepared direct testimony.

**Encoder Receiver Transmitter (ERT) Replacement Project**

**Q. 54 Please describe the ERT Replacement Project.**

A. 54 An ERT is an electronic device attached to a gas meter that records consumption data and transmits that data wirelessly to a data collection device, allowing the Company to collect customer meter data for monthly billing purposes. The ERT Project is a companywide initiative to replace ERTs that are reaching the manufacturer's twenty-year life expectancy. The factors that affect ERT lifespan are the battery within the ERT, environmental conditions, and mechanical wear. A faulty ERT can lead to incorrect billing or difficulty in obtaining consumption data. Company witness Kevin M. Lang supports the need for and discusses the Company's ERT Project in his prepared direct testimony.

**Q. 55 How will the ERT Replacement Project be implemented in Southern Nevada?**

A. 55 Southwest Gas will leverage Company and/or contractor resources to replace existing 40G ERTs with new AMR-type ERT devices in alignment with currently budgeted dollars.

**Q. 56 What is the total estimated capital investment for the ERT Replacement Project in Southern Nevada over the action plan period?**

A. 56 The estimated cost of the ERT Replacement Project is $21 million in Southern Nevada over the action plan period and is provided in the table below.

| Category | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| ERT Replacement Project | $7,000,000 | $7,000,000 | $7,000,000 | $21,000,000 |

**Q. 57 Please provide a summary of the estimated cost of System Integrity Projects planned during the action plan period.**

A. 57 The table below summarizes the estimated costs of the System Integrity Projects planned during the action plan period.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Lamb Tap Project | $20,400,000 | $0 | $0 | $20,400,000 |
| Grand Teton Project | $0 | $2,500,000 | $0 | $2,500,000 |
| STS L-Line Integrity Management Replacement Project | $0 | $8,500,000 | $0 | $8,500,000 |
| ERT Replacement Project | $7,000,000 | $7,000,000 | $7,000,000 | $21,000,000 |
| Total System Integrity Projects | $27,400,000 | $18,000,000 | $7,000,000 | $52,400,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the System Integrity Projects in his prepared direct testimony.

**Q. 58 Does the Company anticipate any incremental operating costs related to the ERT Replacement Project discussed above?**

A. 58 No, the Company does not anticipate an increase in operating costs related to the ERT Replacement Project.

## VI. DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM PROJECTS

**Q. 59 Please provide a brief overview of the Company's Distribution Integrity Management Program (DIMP) Projects.**

A. 59 The purpose of DIMP is to enhance safety by identifying and reducing natural gas distribution pipeline integrity risks. Evaluation and ranking of risk are part of DIMP. Synergi Pipeline is the quantitative relative risk model software used for DIMP. Synergi Pipeline will perform the evaluation of pipeline segments based on a mathematical algorithm that considers: (1) each applicable current and potential threat; (2) the likelihood of failure associated with each threat; (3) the potential consequences of such failure; (4) the risk rankings (i.e., determine the relative importance) posed to the pipelines; and (5) the relevance of threats in one location to other areas. The Company implements risk management measures to reduce the likelihood of failure and minimize the consequences of an occurrence. The Synergi risk assessment (SRA) process will provide a relative risk ranking of distribution facilities and identify the riskiest segments for replacement. Company witness Kevin M. Lang supports and discusses the Company's DIMP in his prepared direct testimony.

**Q. 60 What Significant Operational or Capital Requirements are currently underway and planned pursuant to the Company's DIMP during the action plan period?**

A. 60 The Significant Operational or Capital requirements currently underway and planned pursuant to the Company's DIMP are:

- 7000/8000 Driscopipe Replacements
- Early Vintage Plastic Pipe (EVPP) Project

**<u>7000/8000 Driscopipe Replacement</u>**

**Q. 61 Please provide an overview of the 7000/8000 Driscopipe Replacement.**

A. 61 Driscopipe is the brand name for pipe made by Phillips Driscopipe, Inc., and its predecessor company, Phillips Products Company. The brand name Driscopipe is still in use today. Driscopipe is a polyethylene (PE) plastic pipe type that has been installed in natural gas systems since the 1960s. The family of Driscopipe that is known to be installed in the Southern Nevada system includes Driscopipe model 7000 and 8000 pipes (collectively, 7000/8000 pipe). The 7000/8000 pipe is used for distribution pressure mains and services, typically between one-half inch and six inches in diameter and was installed between 1974 and 2000. The Company currently replaces 7000/8000 pipe employing a risk-based approach using material degradation testing data that is evaluated each year. Starting in 2015, the Company began the proactive process of evaluating samples of degraded pipe in the Company's laboratory using sophisticated material equipment capable of determining the extent of material degradation throughout the wall of the sample pipe in question. This evaluation identified that material degradation does not appear to occur homogeneously throughout the pipe, but primarily from the outer-wall-inward or the inner-wall-outward.

The Company currently collects samples of degraded 7000/8000 pipe whenever material degradation is witnessed when the pipe is exposed in the field. Exposure may occur due to pipe excavations associated with typical field activities such as new facility installations, field repairs, or other operations and maintenance activities. Southern Nevada will initiate the material investigation process and submit samples to the Company's laboratory services. The System Integrity department will notify Southern Nevada when a material defect is confirmed that warrants replacement. The Company's PE pipe inspection procedure requires replacement of all like pipe size 7000/8000 pipe under the following conditions: (1) replace the facilities identified through SRA with a wall thickness loss equal to 17 and less than 20 percent; (2) replace the facilities with a wall thickness loss equal and greater than 20 percent within 18 months from the day of notifications; or (3) replace or abandon ½-inch and 1-inch 7000/8000 services that have been inactive for consecutive periods greater than or equal to 60 months.

**Q. 62 Why does the Company's PE pipe inspection procedure require such replacement?**

A. 62 Replacement of the pipe based on wall loss meets a threshold where manufacturers and industry organizations recommend repair or replacement. Repair is not possible for degraded pipes. Therefore, the Company's PE pipe inspection procedure requires replacement or abandonment.

**Q. 63 What is the estimated cost of the 7000/8000 Replacements over the action plan period?**

A. 63 With respect to this action plan period, the budgeted 7000/8000 Replacements capital costs are presented in the table below:

| Category | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| 7000/8000 Replacements | $24,700,000 | $21,200,000 | $19,500,000 | $65,400,000 |

**Q. 64 Does the Company anticipate any incremental operating costs related to the 7000/8000 Replacements discussed above?**

A. 64 No. In fact, it's possible for Southwest Gas to experience efficiencies because the 7000/8000 Replacements involve the replacement of current facilities with facilities made with newer materials and construction practices. Further, as 7000/8000 pipe is replaced, the scope of leak patrols[6] currently conducted for this pipe will lessen thereby providing an opportunity for the reduction of related operating costs, which are currently incurred at approximately $250,000 annually.

**Early Vintage Plastic Pipe (EVPP) Project**

**Q. 65 Please describe the Early Vintage Plastic Pipe project.**

A. 65 For context, on March 8, 2022, the Commission issued an order which included a directive that required the Company to remove all known EVPP in Southern Nevada by December 31, 2024, unless prevented by circumstances beyond the Company's direct control. There were approximately 120-miles of known EVPP at the time of the stipulation. The Company was on schedule to complete the replacement of known EVPP facilities by December 31, 2024, timeframe, except for approximately 13.5-miles that involved extended permitting circumstances that

[6] The Company currently performs special leak patrols on 7000/8000 pipe, in addition to the annual leak survey of all facilities, including 7000/8000 pipe, conducted pursuant to Nevada Administrative Code (NAC) 703.915.

were outside the Company's control. The Company has replaced most of that 13.5-miles in 2025.

**Q. 66 What is the status of the EVPP project?**

A. 66 There is approximately 1.5-miles of EVPP that will not be completed within the planned timeframe and will be carried over for several years due to a pavement no-cut moratorium. Southern Nevada municipalities have a policy where newly paved or resurfaced streets are temporarily restricted from being cut or opened for utility work to preserve the road's integrity and lifespan. Southern Nevada local jurisdictions have a five-year no-cut moratorium policy. The remaining 1.5-miles of EVPP are inspected annually and will be replaced if there is a change in the pipeline's status.

**Q. 67 What is the estimated cost of the EVPP Replacement Project over the action plan period and what is the mileage anticipated to be replaced?**

A. 67 As discussed above, for the action plan period, Southern Nevada will only have approximately 1.5 miles of EVPP remaining. As that pipe is subject to a no cut moratorium, the Company does not have any specific amounts budgeted for the replacement of that 1.5 miles during the action plan period. The Company will replace the pipe in the ordinary course of business when the no cut moratorium expires or as needed if there is a change in the pipeline's status.

**Q. 68 Does the Company anticipate any incremental operating costs related to the EVPP Replacements discussed above?**

A. 68 No. In fact, it's possible for Southwest Gas to experience efficiencies because the EVPP Replacements involve the replacement of current facilities with facilities made with newer materials and construction practices.

**Q. 69 Please provide a summary of the estimated cost of DIMP Projects planned during the action plan period.**

A. 69 The table below summarizes the estimated costs of the DIMP Projects planned during the action plan period.[7]

| Category | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| 7000/8000 Replacements | $24,700,000 | $21,200,000 | $19,500,000 | $65,400,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the DIMP Projects in his prepared direct testimony.

## VII. TRANSMISSION INTEGRITY MANAGEMENT PROGRAM

**Q. 70 Please provide an overview of the Company's Transmission Integrity Management Program (TRIMP)**

A. 70 TRIMP for natural gas pipelines is a systematic process that pipeline operators use to identify, prioritize, assess, and mitigate risks to ensure the safe and reliable operation of transmission pipelines, particularly those in areas where a failure could have high consequences. The program focuses on preventing, detecting, and mitigating potential incidents. The Company developed TRIMP to comply with the requirements of the U.S. Department of Transportation regulation 49 CFR 192.911, Subpart O – Pipeline Integrity Management. This comprehensive program has been designed to ensure the integrity of gas transmission pipelines located where a leak or rupture could do the most harm. Company witness Kevin M. Lang provides more discussion on the Company's TRIMP in his prepared direct testimony.

[7] Due to the unknown timing of the replacement of the remaining EVPP milage, the estimated cost of EVPP Replacements is not included.

**Q. 71 Does Southern Nevada have a planned TRIMP project during the action plan period?**

A. 71 Yes, Southern Nevada has identified an Assessment Exception Region (AER) Project that the Company intends to perform during the action plan period.

**Q. 72 What is the AER Project?**

A. 72 The Company has reviewed its systems in Southern Nevada and identified segments that will continue to be assessed through conventional or robotic inline inspection and those that will be replaced to eliminate the transmission segment with stronger, and in most cases, thicker wall pipe. The replacement pipes will operate as distribution pipelines at lower percentages of the specified maximum yield stress than the pipelines being replaced. The pipeline that will be replaced is located near the intersection of Topaz Street and Spencer Street. The replacement will eliminate two AERs and enhance pipeline safety by installing stronger pipes.

**Q. 73 Why is the AER Project necessary?**

A. 73 AER refers to specific geographic areas where certain integrity assessments require alternative mitigation. This exception is typically based on a thorough risk assessment and justification by the Company, demonstrating that alternative mitigation measures or inspections techniques can adequately address the identified threats in that specific region. In certain circumstances, segments of pipelines are located under drainage structures, such as a large box culvert. These crossings can result in an AER. An AER is an area in which conventional TRIMP tools for inspection, such as External Corrosion Direct Assessment, which is a systematic process for evaluating the threat of external corrosion on the pipeline, is not able to assess the pipeline. In these situations, additional measures are required to assess the pipeline segment in the AER. The three most common methods for assessing AERs are: (1) conventional inline inspection; (2)

robotic inline inspection; and (3) hydrotesting of the facility. AERs require a reinspection every seven years.

**Q. 74 What is the estimated total cost of the AER Project during the action plan period?**

A. 74 The estimated total cost of the AER project is $3,150,000 million. Company witness Christopher M. Brown discusses the estimated customer bill impact related to the AER Project.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| AER Project | $1,750,000 | $400,000 | $1,000,000 | $3,150,000 |

**Q. 75 Does the Company anticipate any incremental operating costs related to the AER Project discussed above?**

A. 75 No, the Company does not anticipate an increase in operating costs related to the AER Project.

## VIII. NEW PROPOSED SAFETY-RELATED PROGRAMS

**Q. 76 Is the Company proposing to develop and implement safety-related programs as part of its Resource Plan?**

A. 76 Yes. As supported and discussed in the prepared direct testimony of Company witness Kevin M. Lang, the Company is proposing the development and implementation of two new safety-related programs in Southern Nevada during the action plan period. The new safety-related programs are:

- 84/85 Pipe Replacement Program
- Natural Gas Alarm Pilot Program

I discuss each of the proposed programs from an operational perspective in more detail below.

**<u>84/85 Pipe Replacement Program</u>**

**Q. 77 Please provide an overview of the known threat related to vintage 84/85 pipe.**

A. 77 The Company has identified 2-inch PE pipe installed in 1984 and 1985 as a higher risk pipe due to fusion failures. As explained in more detail in the prepared direct testimony of Kevin M. Lang, the Company's DIMP process identified the 2-inch HDPE pipe at butt fusions installed in 1984 and 1985 in the Company's Southern Nevada service territory in the Las Vegas and Laughlin areas as an emerging threat.

**Q. 78 What is the Company's proposed 84/85 Pipe Replacement Program?**

A. 78 The Company is proposing to establish an 84/85 Pipe Replacement Program to all known 84/85 pipe facilities, which would include the replacement of approximately 63 miles of 2-inch main and 59 miles of services.

**Q. 79 Why is the 84/85 Pipe Replacement Program Necessary?**

A. 79 As noted above, and in the prepared direct testimony, of Kevin M. Lang, the 84/85 pipe has been identified as higher risk for leaks. To eliminate this higher risk from the Company's Southern Nevada system, the Company intends to begin a targeted 84/85 Pipe Replacement Program replacing up to 10 miles per year, comprised of a combination of main and service.

**Q. 80 Why is the Company proposing to replace 84/85 pipe now?**

A. 80 As mentioned above and discussed by Mr. Lang, the Company has nearly completed the EVPP Replacement Project established to replace all known EVPP from the Company's Southern Nevada system. Given the limited mileage remaining of EVPP requiring replacement and the emerging threat of 84/85 pipe, the Company believes transitioning to a targeted replacement project focused on removing all known 84/85 from the Company's system is reasonable and manageable from an operational perspective.

**Q. 81 What is the estimated total cost of the 84/85 Replacement Program?**

A. 81 The estimated cost to replace all known 84/85 pipe, approximately 122 miles, is approximately $124 million. However, as the Company is not planning to replace all 84/85 mileage during the action plan period, the estimated cost of the 84/85 Replacement Project during the action plan period is as follows:

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| 84/85 Pipe Replacement Program | $18,000,000 | $18,000,00 | $18,000,000 | $54,000,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and the estimated customer bill impact of the 84/85 Pipe Replacement Program during the action plan period.

**Q. 82 Does the Company anticipate any incremental operating costs related to the 84/85 Replacement Program discussed above?**

A. 82 No. In fact, it's possible for Southwest Gas to experience efficiencies because the 84/85 Replacement Program involves the replacement of current facilities with facilities made with newer materials and construction practices. Further, as 84/85 pipe is replaced, the scope of leak surveys currently conducted for this pipe[8] will lessen thereby reducing the related operating costs, which are currently incurred at approximately $100,000 annually.

<u>**Natural Gas Alarm Pilot Program (Pilot Program)**</u>

**Q. 83 Please provide an overview of the Company's proposed Pilot Program.**

A. 83 The Company is proposing to purchase, distribute and install up to 10,000 natural gas alarms in Nevada during a 3-year period to a target audience that consists of underserved residential communities, churches, community centers, and educational facilities, including daycares and pre-schools, as well as customers

[8] The Company currently performs special leak surveys on 84/85, in addition to the annual leak survey of all facilities, including 84/85 conducted pursuant to NAC 703.915.

outside of the target audience that would like to participate in the Pilot Program. A detailed description of the Company's proposed Natural Gas Alarm Pilot Program is provided in the prepared direct testimony of Company Witness Kevin M. Lang.

**Q. 84 How will the proposed Pilot Program be implemented in Southern Nevada?**

A. 84 Subsequent to receiving Commission approval of this Resource Plan, the Company intends to implement the Pilot Program through outreach and public awareness to facilitate the distribution and installation of approximately 8,750 natural gas alarms, during a 3-year period, to a target audience that includes, for example, community centers, churches, educational facilities, and low-income communities, as well as other customers who are interested in participating in the program. The Company will utilize Company and/or contract resources to distribute and install the natural gas alarms, with customer permission, according to the manufacturer's recommendation.

**Q. 85 What are the estimated costs for the Pilot Program during the action plan period?**

A. 85 The estimated Pilot Program costs for Southern Nevada during the action plan period are as follows:

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Natural Gas Alarm Pilot Program | $1,245,000 | $572,000 | $572,000 | $2,400,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impact of the new Safety-Related Programs as proposed in his prepared direct testimony.

**Q. 86 Does the Company anticipate any incremental operating costs related to the Pilot Program discussed above?**

A. 86 Southwest Gas anticipates some amount of incremental operating costs associated with the Natural Gas Alarm Pilot Program to engage contractors for assistance with targeting communications to potential participants and for installation costs. Those costs, however, are incorporated into the estimated costs of the Pilot Program identified in the table above. Beyond those activities, Southwest Gas anticipates a negligible amount of incremental operating costs related to tracking the success of the Pilot Program and responding to calls for potential natural gas leaks that arise from the natural gas alarms.

## IX. COYL REPLACEMENT PROGRAM

**Q. 87 What is a COYL?**

A. 87 A COYL refers to the underground houseline running from the meter to the customer's building, which is owned and maintained by the customer. Due to limited awareness and resources, customers often do not monitor these service lines, posing potential safety risks.

**Q. 88 Please provide an overview of the currently authorized COYL-Replacement Program.**

A. 88 The Company initially proposed a statewide COYL Replacement Program in its 2016 GIR Advance Application (Docket No. 16-06001). The Commission did not approve a COYL Replacement Program at that time for Southern Nevada, but did approve the implementation of a Northern Nevada COYL Replacement Program eligible for cost recovery pursuant to the GIR Mechanism finding that COYLs present unique safety and reliability issues that justify replacement on an accelerated basis.[9] Those issues include: 1) that the COYL pipelines are subject to corrosion and leaks; 2) COYLs are supposed to be maintained and monitored

[9] Order at pages 26-27.

by the customers who own them and therefore are not maintained, or leaks surveyed by the Company; and 3) the pipelines are in close proximity to homes and structures.

Southwest Gas' COYL Replacement Program was expanded in Docket No. 21-08003 to allow the Company to replace residential and public school COYLs in both its Northern and Southern Nevada service territories over a five-year period. The Company is permitted to include other individual COYL replacements in the program as specific or as emergency needs arise, such as COYLs discovered at non-profit and/or other publicly funded facilities where private funding is limited or unavailable for COYL replacement and the COYL is believed to be a safety concern. The program aims to relocate meters to the building and remove the COYL piping owned by the customer and install infrastructure owned and maintained by the Company to the relocated meter. Participation in the program is voluntary and requires customer approval prior to performing work. The Commission approved regulatory asset treatment for the COYL Replacement Program-related costs and established a program end date of June 30, 2027.

**Q. 89 What is the Company's proposal with respect to the COYL Replacement Program?**

A. 89 Given that the currently-authorized COYL Program concludes during the action plan period for this Resource Plan, the Company requests that the Commission authorize the Company to continue the COYL Replacement Program through the end of 2028, at amounts currently authorized, including an annual statewide budget of $5 million with approximately $2 million allocated to Northern Nevada and approximately $3 million allocated to Southern Nevada and maintaining the cost recovery treatment currently authorized. The Southern Nevada capital investment for the COYL Replacement Program during the action plan period is shown below.

| Description | 2026 Authorized | 2027 Authorized | 2028 Proposed | 3-Year Total |
|---|---|---|---|---|
| COYL Replacement Program | $3,000,000 | $3,000,000 | $3,000,000 | $9,000,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the COYL Replacement Program in his prepared direct testimony.

**Q. 90 What process has the Company undertaken to identify and prioritize COYL replacements?**

A. 90 To achieve the goal of replacing the majority of at risk public school COYLs throughout the Company's Nevada service territory, Southern Nevada ranked the schools within the Clark County School District (CCSD) for COYL replacement according to the best information available including any known factors regarding the COYLs, such as proximity of student occupied buildings to the COYL, age of the COYL, pipe material, and leak history. This was used to prioritize known CCSD COYLs for replacement. If an emergency is discovered involving a public school, such as a leak requiring immediate repair, then COYL replacement is given priority.

**Q. 91 How many COYL replacements have been completed to date in Southern Nevada?**

A. 91 To date, the Company has completed the replacement of six CCSD COYLs. The Company has conducted outreach with the CCSD to promote the program. The Company will continue its partnership with the CCSD to facilitate future CCSD COYL replacements.

**Q. 92 Will the Company begin actively pursuing residential COYL replacements and if so, what is the Company's approach in doing so?**

A. 92 Yes, while the Company will continue outreach to the CCSD for the replacement of school COYLs, the Company also plans to begin actively pursuing the replacement of residential COYLs in Southern Nevada. The Company has identified nearly 7,000 residential COYLs in Southern Nevada for potential replacement. The Company has defined two categories of COYL replacement work; 1) residential COYL and 2) residential COYL associated with DIMP-driven replacements. The residential COYL category contemplates the replacement of a COYL that would not otherwise be considered in the Company's planned work, whereas a COYL associated with DIMP-driven replacements is one where a residential COYL is present in an area where a DIMP driven replacement project (of Company-owned facilities) is taking place. This approach will allow the Company to efficiently plan COYL replacements, optimizing resource availability.

For DIMP replacement with residential COYL, the replacement project will include COYLs in the design of the work and the costs for the COYL replacement will be tracked separately. The residential outreach will consist of five actions. 1) Initial customer notification and explanation of the issue (Affected customers will be sent emails and/or letters and door hangers to explaining the enhanced safety of COYL replacement and clearly stating the potential risks.); 2) Perform site assessment to understand scope of work and emphasize the benefits of COYL replacement for the customer; 3) Following customer approval, provide clear instructions and options by giving customers a dedicated phone number or email address for questions, coordination, and scheduled replacement; 4) Address specific concerns with construction activities, such as yard restoration efforts; and 5) Ongoing communications and post construction follow-up.

**Q. 93 Does the Company anticipate any incremental operating costs related to the COYL Replacement Program discussed above?**

A. 93 As previously discussed, the Company proposes to continue the COYL Replacement Program through the end of 2028, at the $3 million annual amount as currently authorized in Southern Nevada. With respect to the cost of operation, the Company anticipates a negligible amount of incremental operating costs related to the new Company-owned facilities resulting from any COYL replacement.

**Q. 94 Does this conclude your prepared direct testimony in this matter?**

A. 94 Yes.

**SUMMARY OF QUALIFICATIONS**
**THOMAS CARDIN**

I graduated from the University of Nevada at Las Vegas in 1996 and in 2001 with a Bachelor of Science degree and a Master of Science degree in Mechanical Engineering. I graduated from Colorado State University in 2014 with a Master of Business Administration degree.

I began my career with Southwest as an Engineer in the Southern Nevada Division (SND) engineering department in 1996. I was assigned responsibility for the design of distribution and transmission facilities, project management, and regulatory audits. In 2000, I was promoted to Engineering Supervisor in the SND engineering department. My responsibilities included the supervision of franchise and new business activities, development of short and long-term operational planning initiatives, and regulatory matters. I was promoted to Engineering Manager of Paiute Pipeline Company in 2004. In addition to day-to-day management, my responsibilities included the management of construction, engineering, technical services, and compressor station departments and system operations. I represented Paiute Pipeline in PHMSA regulatory audits.

From 2005 to 2008, I was employed by Focus Property Group as Vice-President of Community Development. My responsibilities were primarily involved in the management of commercial and residential real estate and master-planned community developments in California and Nevada. I managed Desert Utilities, Inc., which is a water and wastewater utility, located in Pahrump, NV.

In September 2008, I returned to Southwest as an Engineering Supervisor and subsequently was promoted to Key Account Management Supervisor in 2010. I was responsible for transportation accounts in California and Nevada. In 2011, I was promoted to Engineering Manager of the SND engineering department. My responsibilities included the management of engineering, right-of-way, regulatory, and GIS. I was promoted to Director of Gas Operations in 2014. During my ten years as Director, I managed the SND construction, engineering, technical services, Bullhead City district, administration, and special projects. I was promoted to Vice-President of Gas Operations in 2024. I am responsible for the SND operations in Bullhead City district, Arizona, Needles, California, and Southern Nevada with approximately 380 Southwest employees and with an annual budget of $285 million. SND Gas Operations serves approximately 762,000 customers.

**AFFIRMATION OF THOMAS CARDIN**

Pursuant to NAC 703.710, Thomas Cardin affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 15th day of September, 2025

THOMAS CARDIN

Exhibit 5

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY

OF

CHRISTOPHER R. ANDERSON

ON BEHALF OF

SOUTHWEST GAS CORPORATION

September 17, 2025

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of
Prepared Direct Testimony
of

Christopher R. Anderson

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Christopher R. Anderson

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Christopher R. Anderson. My business address is 400 Eagle Station Lane, Carson City, NV 89701.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) and my title is Vice President/Northern Nevada Division.

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 No.

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 The purpose of my prepared direct testimony is to provide an overview of and support for the Significant Operational or Capital Requirements that the Company plans to implement in the Northern Nevada rate jurisdiction throughout the action plan period.[1] I also provide support for why each activity is required to provide safe and reliable service to the Company's customers and the estimated cost of construction for each activity. Finally, I support, from an operations perspective,

[1] As defined in the Commission's Proposed Regulation submitted to the Legislative Counsel Bureau November 25, 2024, "action plan period" means the three-year period immediately following the date on which a resource plan is filed with the Commission.

the continuation of the currently authorized Customer-Owned Yard Line (COYL) Replacement Program and new proposed safety-related programs.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My prepared direct testimony consists of the following key items:

- Description of the planning for and oversight of capital investments for projects in the Northern Nevada Division (Northern Nevada);
- An overview of the Significant Operational or Capital Requirements included in the Company's Triennial Resource Plan (Resource Plan);
- A discussion of and support for the system integrity projects required to maintain customers' level of service;
- A discussion of and support for the continuation of the COYL Replacement Program;
- Support for the development of the Company's two (2) new proposed safety-related programs, namely the Natural Gas Alarm Pilot Program and the Meter Protection Program, and their implementation in Northern Nevada.

## II. CAPITAL INVESTMENT PROCEDURAL FRAMEWORK AND OVERSIGHT FOR NORTHERN NEVADA

**Q. 7 Please describe the process for planning and oversight of capital investment projects in Northern Nevada.**

A. 7 The Northern Nevada planning and oversight process for capital investments focuses on a continuous, collaborative, interdepartmental approach across various stakeholder groups and, depending on project complexity, generally follows a structured, work management framework that involves identifying projects, planning and managing projects, executing and completing projects, and assessing efficiencies and effectiveness of completed projects.

The initial phase involves the identification of a capital project. Input and internal expertise from various departments such as engineering, construction, technical services, customer service, and staff support departments are utilized to identify system trends and safety-related risks. Specific projects and/or multi-year programs are developed to manage, mitigate and minimize these risks. External stakeholders may also be consulted in specific instances for added insights into a particular project.

Once a project is identified, Northern Nevada plans the project by evaluating the anticipated length of time, costs, work requirements and resources needed for identified projects. The planned projects are then prioritized and organized into a schedule. Projects are then generally executed based on the schedule. Finally, Northern Nevada implements a formal process for completing projects and analyzes the efficiencies and effectiveness of the project for continuous improvement.

This approach to capital investment and project management aids in improved efficiencies by streamlining work processes, enhancing reliability through identification of issues, effectively managing resources, and fostering a continuous improvement culture by evaluating metrics and incorporating lessons learned into future capital investment planning iterations. The Northern Nevada capital budget goes through an extensive, iterative review process with senior management and ultimately the final capital budget, as proposed, is presented to the Company's Board of Directors for final approval.

**Q. 8 How does Northern Nevada determine when pipelines need to be replaced?**

A. 8 Throughout the capital investment planning process outlined above, Northern Nevada continuously evaluates the many different facets associated with replacement activities for prioritization and timing. Factors considered include but are not limited to projects identified through the Company's annual Distribution Integrity Management Program (DIMP) SynerGI Risk Assessment (SRA) process, localized relative risk ranking for Northern Nevada pipeline segments, Vintage

Steel Pipe (VSP) replacement projects, system uprating for improved pressures, and routine work that leads to replacements, such as those driven by, for example line breaks, leaks and relocations.

**Q. 9 Please explain how the cost estimates for the projects discussed in your testimony were developed.**

A. 9 The estimated costs for the projects discussed in my testimony are based on historical costs for similar work with certain adjustments or considerations based upon current construction activity. The actual costs incurred will be impacted by many factors, both known and unknown. A new known factor is that, in 2025, the Nevada Legislature passed Senate Bill 443 which requires the payment of prevailing wages for construction work awarded to a contractor for the replacement of a natural gas pipeline approved in a plan submitted pursuant to NRS 704.991. Southwest Gas does not know with certainty how that requirement will impact the costs of applicable projects as the Company does not have the historical wage rates of the Company's contractors' employees, so it is unable to estimate how the prevailing wage requirement will ultimately impact overall costs.

## III. OVERVIEW OF SIGNIFICANT OPERATIONAL OR CAPITAL REQUIREMENTS INCLUDED IN THE RESOURCE PLAN

**Q. 10 Please describe what qualifies as Significant Operational or Capital Requirement pursuant to a resource plan.**

A. 10 As defined in Senate Bill (SB) 281, Significant Operational or Capital Requirements means the construction of a new transmission, distribution, compression or storage facility or the rehabilitation, replacement, modification, upgrade, uprate or update of existing facilities, or any planned series of such activities addressing the same need, in which the anticipated cost exceeds the threshold established by the Commission pursuant to subsection 3 of Nevada

Revised Statutes (NRS) 704.991. The Commission's proposed regulations[2] have established a $5 million threshold for Significant Operational or Capital Requirements, as well as three additional qualifying activities including, in summary: (1) construction of a single extension facility with 2,000 or more new customers or with a forecasted maximum annual load over the next five years that is greater than two percent of the gas utility's forecasted load during the first year; (2) any long-term arrangement resulting from a gas utility's request for incremental upstream resources that requires an interstate pipeline to receive approval from the Federal Energy Regulatory Commission (FERC); and (3) investment in infrastructure that facilitates the introduction of nongeologic gas into the gas utility's system.

**Q. 11 Has the Company included Significant Operational or Capital Requirements, in its Resource Plan that are anticipated in Northern Nevada during the action plan period?**

A. 11 Yes. The Company has construction-related capital expenditure projects currently underway, and planned, in Northern Nevada that are estimated to exceed the established $5 million threshold during the action plan period. I discuss each of these projects below.

The Company currently does not anticipate a Significant Operational or Capital Requirement of any new single extension facilities required to serve 2,000 or more new customers in Northern Nevada, or a project with anticipated demand that is greater than two percent of Southwest Gas' Northern Nevada forecasted load during the first year. In this Application, the Company is also not proposing

[2] On July 25, 2023, the Commission opened a rulemaking, designated as Docket No. 23-07024, to amend, adopt, and/or repeal regulations in accordance with SB 281 (2023). The Commission's proposed regulations, drafted in accordance with SB281, were submitted to the Legislative Counsel Bureau November 25, 2024,

investment in infrastructure that facilitates the introduction of nongeologic gas into its Northern Nevada system.

Company witness Laura Spurlock discusses a significant operational requirement that contemplates a long-term arrangement resulting from the Company's request for incremental upstream resources from an interstate pipeline to serve Northern Nevada customer demand.

**Q. 12 Please provide an overview of the construction-related Significant Operational or Capital Requirements for Northern Nevada that are currently underway and planned during the action plan period.**

A. 12 Northen Nevada has multiple Significant Operational or Capital Requirements that are underway, and planned, for the next three years. Below, I have compiled the Significant Operational or Capital Requirements associated with system integrity related projects in Northern Nevada. I discuss each of the planned system integrity projects below.

**Q. 13 Are there other projects or programs that you discuss below?**

A. 13 Yes, in addition to the Significant Operational and Capital Requirements projects underway or planned, my testimony also discusses the Company's proposal to continue the COYL Replacement Program through the end of 2028 and the implementation of the following new programs in Northern Nevada:

- Natural Gas Alarm Pilot Program; and
- Meter Protection Program.

## IV. SYSTEM INTEGRITY PROJECTS

**Q. 14 What is a system integrity project?**

A. 14 A system integrity project is undertaken to ensure the Company's system continues to provide safe, reliable and resilient service to its customers and may contemplate a variety of facilities, including, but not limited to, mains, services, meters, regulator stations and related appurtenances. The Company has the following three project categories for its planned system integrity projects in Northern Nevada during the action plan period: (1) Vintage Steel Pipe (VSP) Replacement Projects, (2) Isolated Steel Services Replacement Project and (3) the Encoder Receiver Transmitter (ERT) Replacement Program

Northern Nevada is actively planning for the construction of three VSP system integrity projects (the Genoa Lateral Replacement Project, the Capehart Lateral Replacement Project and the Wadsworth Lateral Replacement Project (collectively VSP Replacement Projects)) during the action plan period. Company witness Kevin M. Lang discusses safety and reliability concerns related to VSP from a pipeline safety perspective in his prepared direct testimony.

The Isolated Steel Services Replacement Project targets the replacement of short sections of buried main or transmission metallic piping that are not in excess of 100 feet (30 meters), or metallic services of any length and all are electrically isolated from other metallic piping and structures.

The Company has also planned the ERT Replacement Program, which is a system integrity project to replace the current aging population of 40G ERTS with new AMR-type ERT devices to ensure the integrity of the Company's customer billing. Company witness Kevin M. Lang supports and discusses the ERT Replacement Program in his prepared direct testimony.

I discuss the VSP Replacement Projects, the Isolated Steel Service Replacement Project and the ERT Replacement Program in more detail below.

**<u>Genoa Lateral Replacement Project</u>**

**Q. 15 Please provide an overview of the Genoa Lateral Replacement Project.**

A. 15 The Genoa Lateral Replacement Project involves the replacement of approximately 1 mile of 2-inch VSP installed in 1966 along Genoa Lane near the town of Genoa. (Genoa Lateral Project) The Genoa Lateral Project will abandon and replace high-pressure distribution feeder pipe currently operating at 200-psig with 6-inch steel operating at 200-psig. The engineering design for this project is near final design with permits pending with the Nevada Division of State Lands. Construction of the Genoa Lateral Project is currently anticipated to be completed in 2026. Please refer to Appendix F, sheet Appendix F-15, of the Resource Plan for a map of the Genoa Lateral Project.

**Q. 16 Did Southwest Gas contemplate any other alternatives relating to the Genoa Lateral Project?**

A. 16 Yes. Abandonment of the Genoa Lateral is not a viable alternative because abandonment would leave the Town of Genoa and approximately 660 residential and customers without a source of gas. A portion of the VSP on the Genoa Lateral was replaced with 6-inch steel pipe in 2009 in conjunction with a reinforcement project. As this area of Douglas County continues to grow, the existing 2-inch VSP will need to be upsized to meet capacity requirements. The existing pipeline has capacity and operational pressure constraints and cannot be further uprated due to the unknown material properties of the pipeline. As a result of these constraints, it is not feasible to operate the pipeline at any higher pressures than it is currently operating, which limits the capacity of the line. Replacing the existing 2-inch line with a 4-inch steel pipeline would provide additional capacity and reduce some of the system pressure constraints; however, it would also create a bottleneck where the Genoa Lateral transitions from 6-inch to 4-inch. Replacement with 6-inch steel pipe avoids the creation of a bottleneck, reduces the system pressure constraints and provides capacity for future demand. Based on this analysis, Northern Nevada concluded that replacement of the Genoa Lateral with a 6-inch steel pipeline is the preferred alternative.

**Wadsworth Lateral Replacement Project**

**Q. 17 Please provide an overview of the Wadsworth Lateral Replacement Project.**

A. 17 The Wadsworth Lateral Replacement Project involves the replacement of approximately 2.5 miles of 4-inch VSP installed in 1968 in the town of Fernley. (Wadsworth Lateral Project) The Wadsworth Lateral Project will abandon and replace high-pressure distribution feeder pipe currently operating at 267-psig with 6-inch steel operating at 267-psig. Construction of the Wadsworth Lateral Project is currently anticipated to be completed in 2026. Please refer to Appendix F, sheet Appendix F-14, of the Resource Plan for a map of the Wadsworth Lateral Project.

**Q. 18 Did Southwest Gas contemplate any other alternatives relating to the Wadsworth Lateral Project?**

A. 18 Yes. Abandonment of the existing 4-inch Wadsworth Lateral is not a viable alternative because abandonment would leave the Town of Wadsworth and approximately 100 residential and commercial customers without a source of gas. Additionally, the Wadsworth Lateral provides a necessary feed to the distribution system that serves residential and commercial customers in west Fernley. As these areas of Washoe County and Lyon County continue to grow, the existing 4-inch VSP will need to be upsized to meet capacity requirements. The existing pipeline has capacity and operational pressure constraints and cannot be further uprated due to the unknown material properties of the pipeline. As a result of these constraints, it is not feasible to operate the pipeline at any higher pressures than it is currently operating, which limits the capacity of the line. Replacing the existing Wadsworth Lateral with 6-inch steel would provide additional capacity and reduce pressure constraints; however, as the Fernley area continues to grow, 6-inch pipe would limit the amount of future demand. Based on this analysis, Northern Nevada concluded that replacement of the Wadsworth Lateral with an 8-inch steel pipeline is the preferred alternative.

**Capehart Lateral Replacement Project**

**Q. 19 Please provide an overview of the Capehart Lateral Replacement Project.**

A. 19 The Capehart Lateral Replacement Project involves the replacement of approximately 1.5 miles of 4-inch VSP installed near the Fallon Naval Air Station in Fallon (Capehart Lateral Project). The Capehart Lateral Project will abandon and replace high-pressure distribution feeder pipe currently operating at 164-psig with 6-inch steel operating at 164-psig. Construction of the Capehart Lateral Project is currently anticipated to be completed in 2027. Please refer to Appendix F, sheet Appendix F-13, of the Resource Plan for a map of the Capehart Lateral Project.

**Q. 20 Did Southwest Gas contemplate any other alternatives relating to the Capehart Lateral Project?**

A. 20 Yes. Abandonment of the existing 4-inch Capehart Lateral is not a viable alternative because it is the sole feed of natural gas to the Fallon Naval Air Station. The existing pipeline has capacity and operational pressure constraints and cannot be further uprated due to the unknown material properties of the pipeline. As a result of these constraints, it is not feasible to operate the pipeline at any higher pressures than it is currently operating, which limits the capacity of the line. Replacing the existing Capehart Lateral in-kind with 4-inch steel would continue to limit growth potential for the existing on-base residential and commercial uses. Based on this analysis, Northern Nevada concluded that replacement of the Capehart Lateral with a 6-inch steel pipeline is the preferred alternative.

**Q. 21 Has the Company recently replaced other VSP facilities in Northern Nevada?**

A. 21 Yes. The Company replaced the Battle Mountain Lateral, originally installed in 1964, with new 6-inch high-pressure distribution steel pipeline operating at 400-

psig that was placed in service in 2018. The Company also replaced the Jungo Lateral, originally installed in 1964, with a new 8-inch steel high-pressure distribution pipeline operating at 550-psig that was placed in service in 2021. In addition, distribution pressure VSP facilities are being replaced in Winnemucca in 2025 in preparation for a future maximum operating pressure increase to enhance system pressures, operability and reliability for customers in that area.

**Q. 22 What is the estimated cost for Northern Nevada's VSP Replacement Projects during the action plan period?**

A. 22 The pre-construction design cost estimates for the VSP Replacement Projects are included below.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Genoa Lateral Project | $1,800,000 | $0 | $0 | $1,800,000 |
| Wadsworth Lateral Project | $3,500,000 | $0 | $0 | $3,500,000 |
| Capehart Lateral Project | $0 | $2,500,000 | $0 | $2,500,000 |
| **Total VSP Replacement Projects** | **$5,300,000** | **$2,500,000** | **$0** | **$7,800,000** |

**Isolated Steel Service Replacement Project**

**Q. 23 What is the Isolated Steel Service Replacement Project?**

A. 23 Isolated Steel is considered to be short sections of buried main or transmission metallic piping that are not in excess of 100 feet (30 meters), or metallic services of any length and all are electrically isolated from other metallic piping and structures. As required by 49 CFR 192.465, these electrically isolated steel pipeline segments must be surveyed on a sampling basis to ensure adequate cathodic protection. Specifically, 49 CFR 192.465(a) provides that "[a]t least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period." In an effort to eliminate these isolated steel facilities, Northern Nevada began a proactive approach in 2025 to replace existing isolated steel services with high-density polyethylene pipe. Northern Nevada is anticipating approximately $3 million in costs throughout the action plan period associated with the Isolated Steel Service Replacement Project.

**Q. 24 How many isolated steel services are in Northern Nevada's system?**

A. 24 The Company has approximately 237 known isolated steel services remaining in its Northern Nevada distribution system. Under its current plan, the Company anticipates it will take approximately four years to complete replacement of the isolated steel services remaining in its system.

**Q. 25 What process will Northern Nevada use to select the isolated steel services for replacement?**

A. 25 The Company will select isolated steel service replacements primarily based on location. Replacing isolated steel services near each other within relative proximity helps to improve efficiency of pipe replacement and pavement restoration. Therefore, isolated steel services will be grouped by city and crews will replace all services in that city before moving to the next city.

**Q. 26 What is the estimated cost for Northern Nevada's Isolated Steel Service Replacement Project during the action plan period?**

A. 26 The pre-construction cost estimates for the Isolated Steel Service Replacement Project during the action plan period are as follows:

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Isolated Steel Service Replacement Project | $1,000,000 | $1,000,000 | $1,000,000 | $3,000,000 |

**<u>Encoder Receiver Transmitter (ERT) Replacement Program</u>**

**Q. 27 Please describe the ERT Replacement Program.**

A. 27 An ERT is an electronic device attached to a natural gas meter that records consumption data and transmits that data wirelessly to a data collection device, allowing the Company to collect customer meter data for monthly billing purposes. The ERT Replacement Program is a Companywide initiative to replace ERTs that are reaching the manufacturer's twenty-year life expectancy. The factors that affect ERT lifespan are the battery within the ERT, environmental conditions, and mechanical wear. A faulty ERT can lead to incorrect billing or difficulty in obtaining consumption data. Company witness Mr. Lang supports the need for and discusses the Company's ERT Replacement Program in his prepared direct testimony.

**Q. 28 How will the ERT Replacement Program be implemented in Northern Nevada?**

A. 28 Southwest Gas will leverage Company and/or contractor resources to replace existing 40G ERTs with new AMR-type ERT devices in alignment with the estimated cost of the currently planned program.

**Q. 29 What is the estimated capital investment for the ERT Replacement Program in Northern Nevada over the action plan period?**

A. 29 The estimated cost of the ERT Replacement Program is $3.9 million in Northern Nevada over the action plan period.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| ERT Replacement Program | $1,300,000 | $1,300,000 | $1,300,000 | $3,900,000 |

Company witness Christopher M. Brown discusses the cost recovery and the estimated customer bill impact of the ERT Replacement Program in his prepared direct testimony.

**Q. 30 Do the VSP Replacements Projects, the Isolated Steel Replacement Project and the ERT Replacement Program encompass all of the pipe replacement projects in Northern Nevada?**

A. 30 No. Northern Nevada has other replacement projects that the Company addresses on a day-to-day basis. Such work can involve replacement of mains and services driven by the remediation of line breaks (i.e., third-party damage), leaks and relocations in general, and, in the absence of a targeted service replacement program, normal course of business work associated with service replacements. These day-to-day projects are performed in the normal course of business and are not otherwise a significant operational or capital requirement.

**Q. 31 Please provide a summary of the estimated cost of System Integrity Projects planned during the action plan period.**

A. 31 The table below summarizes the estimated costs of the System Integrity Projects planned during the action plan period.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Genoa Lateral Project | $1,800,000 | $0 | $0 | $1,800,000 |
| Wadsworth Lateral Project | $3,500,000 | $0 | $0 | $3,500,000 |
| Capehart Lateral Project | $0 | $2,500,000 | $0 | $2,500,000 |
| **Total VSP Replacements** | **$5,300,000** | **$2,500,000** | **$0** | **$7,800,000** |
| Isolated Steel Service Replacement | $1,000,000 | $1,000,000 | $1,000,000 | $3,000,000 |
| ERT Replacement Program | $1,300,000 | $1,300,000 | $1,300,000 | $3,900,000 |
| **Total System Integrity Projects** | **$7,600,000** | **$4,800,000** | **$2,300,000** | **$14,700,000** |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the System Integrity Projects in his prepared direct testimony.

**Q. 32 Does the Company anticipate any incremental operating costs related to the System Integrity Projects discussed above?**

A. 32 No. In fact, it's possible for Southwest Gas to experience efficiencies because the System Integrity Projects involve the replacement of current facilities with facilities made with newer materials and construction practices.

**Q. 33 Does the Company anticipate any incremental operating costs related to the System Integrity Projects discussed above?**

A. 33 No. In fact, it's possible for Southwest Gas to experience efficiencies because the System Integrity Projects involve the replacement of current facilities with facilities made with newer materials and construction practices.

## V. COYL REPLACEMENT PROGRAM

**Q. 34 What is a COYL?**

A. 34 A COYL refers to the underground houseline running from the meter to the customer's building, which is owned and maintained by the customer. Due to limited awareness and resources, customers often do not monitor these service lines, posing potential safety risks.

**Q. 35 Please provide an overview of the COYL Replacement Program in Northern Nevada.**

A. 35 The Commission approved a Northern Nevada COYL Replacement Program for the Company in Docket No. 16-06001 and concluded that the program was eligible for Gas Infrastructure Replacement (GIR) treatment because COYLs present unique safety and reliability issues that justify replacement on an accelerated basis.[3] Those issues include: 1) that the COYL pipelines are subject to corrosion and leaks; 2) COYLs are supposed to be maintained and monitored by the customers who own them and therefore are not maintained, or leak surveyed by the Company; and 3) the pipelines are in very close proximity to homes and structures.

Southwest Gas' COYL Replacement Program was expanded in Docket No. 21-08003 to allow the Company to replace residential and public school COYLs in both its Northern and Southern Nevada service territories over a five-year period. The Company is permitted to include other individual COYL

[3] Order at pages 26-27.

replacements in the program as specific or as emergency needs arise, such as COYLs discovered at non-profit and/or other publicly funded facilities where private funding is limited or unavailable for COYL replacement and the COYL is believed to be a safety concern. The program aims to relocate meters to the building and replace COYL piping with infrastructure owned and maintained by the Company. Participation in the program is voluntary and requires customer approval prior to performing work. The Commission approved regulatory asset treatment for the COYL Replacement Program-related costs and established a program end date of June 30, 2027.

**Q. 36 What is the Company's proposal with respect to the COYL Replacement Program?**

A. 36 Given that the currently-authorized COYL Program concludes during the action plan period for this Resource Plan, the Company requests that the Commission authorize the Company to continue the COYL Replacement Program through the end of 2028, at amounts as currently authorized, including an annual statewide budget of $5 million with approximately $2 million allocated to Northern Nevada and approximately $3 million allocated to Southern Nevada and maintaining the cost recovery treatment currently authorized. The Northern Nevada capital investment for the COYL Replacement Program during the action plan period is shown below.

| **Description** | **2026 Authorized** | **2027 Authorized** | **2028 Proposed** | 3-Year Total |
|---|---|---|---|---|
| COYL Replacement Program | $2,000,000 | $2,000,000 | $2,000,000 | $6,000,000 |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the COYL Replacement Program in his prepared direct testimony.

**Q. 37 What process has the Company undertaken to identify and prioritize COYL replacements?**

A. 37 To achieve the goal of replacing the majority of at-risk residential and public school COYLs throughout the Company's Nevada service territory, Northern Nevada ranked public school COYLs for replacement according to the best information available as to any know factors regarding the COYLs, such as proximity of student occupied buildings to the COYL, age of the COYL, pipe material, and leak history. This was used to determine a ranked priority for replacement. If an emergency was discovered involving a residential, public school, or other COYL, such as a leak requiring immediate repair, then that COYL replacement was given priority.

**Q. 38 How many COYL replacements have been completed to date in Northern Nevada?**

A. 38 To date, the Company has replaced 1,579 COYLs located within 18 different communities and at 15 different public schools in Northern Nevada. The Company estimates that there are approximately 271 known residential and/or commercial COYLs that have not been replaced in Northern Nevada, in addition to 18 school COYLs. The program has successfully improved safety and decreased risk associated with COYLs, therefore, the Company believes it is in the public interest to continue the COYL Replacement Program through the end of 2028.

**Q. 39 Does the Company anticipate any incremental operating costs related to the COYL Replacement Program discussed above?**

A. 39 As previously discussed, the Company proposes to continue the COYL Replacement Program through the end of 2028, at the $2 million annual amount as currently authorized in Northern Nevada. With respect to the cost of operation, the Company anticipates a negligible amount of incremental operating costs related to the new Company-owned facilities resulting from any COYL replacements.

## VI. NEW PROPOSED SAFETY-RELATED PROGRAMS – NORTHERN NEVADA IMPLEMENTATION

### Natural Gas Alarm Pilot Program (Pilot Program)

**Q. 40 Please provide an overview of the Company's proposed Pilot Program.**

A. 40 The Company is proposing to purchase, distribute and install up to 10,000 natural gas alarms in Nevada during a 3-year period to a target audience that consists of underserved residential communities, churches, community centers, and educational facilities, including daycares and pre-schools, as well as customers outside of the target audience that would like to participate in the Pilot Program. A detailed description of the Company's proposed Natural Gas Alarm Pilot Program is provided in the prepared direct testimony of Company Witness Mr. Lang.

**Q. 41 How will the proposed Pilot Program be implemented in Northern Nevada?**

A. 41 Subsequent to receiving Commission approval of this Resource Plan, the Company intends to implement the Pilot Program through outreach and public awareness to facilitate the distribution and installation of approximately 1,250 natural gas alarms, during a 3-year period, to a target audience that includes, for example, community centers, churches, educational facilities, and low-income communities, as well as other customers who are interested in participating in the program. Southwest Gas will utilize Company and/or contract resources to distribute and install the natural gas alarms, with customer permission, according to the manufacturer's recommendation.

**Q. 42 What are the estimated costs for the Pilot Program during the action plan period?**

A. 42 The estimated Pilot Program costs for Northern Nevada during the action plan period are as follows:

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Natural Gas Alarm Pilot Program | $178,000 | $82,000 | $82,000 | $342,000 |

**Q. 43 Does the Company anticipate any incremental operating costs related to the Pilot Program discussed above?**

A. 43 Southwest Gas anticipates some amount of incremental operating costs associated with the Natural Gas Alarm Pilot Program to engage contractors for assistance with targeting communications to potential participants and for installation costs. Those costs, however, are incorporated into the estimated costs of the Pilot Program identified in the table above. Beyond those activities, Southwest Gas anticipates a negligible amount of incremental operating costs related to tracking the success of the Pilot Program and responding to calls for potential natural gas leaks that arise from the natural gas alarms.

**<u>Meter Protection Program</u>**

**Q. 44 Please provide an overview of the Company's proposed Meter Protection Program.**

A. 44 As further detailed in the prepared direct testimony of Company Witness Kevin M. Lang, the Company is proposing the installation of structurally engineered shelters, or meter sheds, on existing, unprotected customer meters in heavy snow load areas where the meter is located on the eave-side of the house, to help protect natural gas meters from snow and ice loading damage.

**Q. 45 Does the Company install meter sheds pursuant to a Meter Protection Program in any of its other service areas?**

A. 45 Yes. The Company first implemented a Meter Protection Program, which contemplated the installation of meter sheds in its Northern California and South Lake Tahoe service territories, following California Public Utilities Commission approval in its test year 2021 general rate case. A proposal to continue the program is currently being considered in the Company's test year 2026 general rate case. To date, the Company has successfully installed 5,780 meter sheds under its California Meter Protection Program, using a blend of Company and contracted resources for installation.

**Q. 46 How will this Meter Protection Program be implemented in Northern Nevada?**

A. 46 Subsequent to receiving Commission approval, Northern Nevada would dedicate resources throughout 2026 to perform a field verification survey within the heavy snow load areas along the Nevada side of Lake Tahoe. This survey would consist of Company technicians and/or contractors visiting each meter set within the Company's District 23, comprised of Incline Village, Crystal Bay, Stateline, and Kingsbury, Nevada, to verify Company records regarding meter location and to document whether a Meter Shed is present. The resulting data from this survey will be complied into an action plan to begin purchasing and installing Meter Sheds at applicable locations in 2027. With respect to this action plan period, the estimated Meter Protection Program costs were derived using comparable data related to the ongoing Meter Protection Program in the Company's California heavy snow load service territory and are presented below.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Meter Protection Program | $200,000 | $1,000,000 | $1,000,000 | $2,200,000 |

**Q. 47 Does the Company anticipate any incremental operating costs related to the Meter Protection Program discussed above?**

A. 47 Southwest Gas anticipates some amount of incremental operating costs associated with the Meter Protection Program to engage contractors for assistance with targeting communications to potential participants and for installation costs. However, those costs are incorporated into the estimated costs of the Meter Protection Program identified in the table above. Beyond those activities, Southwest Gas is hopeful that efficiencies can be gained through a reduction in the number of snow and ice loading damage incidents that would have otherwise occurred over time.

**Q. 48 Please provide a summary of the estimated cost of New Proposed Safety-Related Programs during the action plan period.**

A. 48 The table below summarizes the estimated costs of the New Proposed Safety-Related Programs during the action plan period, specifically for Northern Nevada.

| Description | 2026 | 2027 | 2028 | 3-Year Total |
|---|---|---|---|---|
| Natural Gas Alarm Pilot Program | $178,000 | $82,000 | $82,000 | $342,000 |
| Meter Protection Program | $200,000 | $1,000,000 | $1,000,000 | $2,200,000 |
| **Total New Proposed Safety-Related Programs** | **$378,000** | **$1,082,000** | **$1,082,000** | **$2,542,000** |

Company witness Christopher M. Brown discusses the proposed cost recovery and estimated customer bill impacts associated with the New Proposed Safety-Related Programs in his prepared direct testimony.

**Q. 49 Does this conclude your prepared direct testimony in this matter?**

A. 49 Yes.

**SUMMARY OF QUALIFICATIONS**
**CHRISTOPHER R. ANDERSON**

I graduated from the University of Nevada, Reno in 2005 with a Bachelor of Science degree in Mechanical Engineering and a Minor in Mathematics.

I began my career with Southwest Gas Corporation (Southwest Gas) as an Engineer in the Northern Nevada Division (NNV) in 2007. I was assigned responsibility for the design of transmission facilities, compliance reviews, project management, and regulatory audits associated with Southwest Gas' wholly owned subsidiary Great Basin Gas Transmission Company (Great Basin; formerly known as Paiute Pipeline Company).

In 2010, I was promoted to Engineering Supervisor in the NNV engineering department. My responsibilities included the supervision, oversight and general project management over all new and replacement capital distribution facility designs.

In 2012, I was promoted to Plant Manager at the Liquified Natural Gas (LNG) Plant, with oversight for strategic planning and execution of all capital, operations and maintenance projects for Great Basin's LNG Plant outside Lovelock, Nevada. I also represented Great Basin during LNG Plant regulatory audits performed by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Federal Energy Regulatory Commission (FERC). I transferred to the Southern Nevada Division (SNV) in 2015 as the Technical Services Manager, with responsibilities including oversight for capital, operations and maintenance activities associated with large measurement and pressure control facilities, cathodic protection, pipeline odorization and the Davis Dam Compressor Station. In 2016, I transitioned to the Engineering Manager role in SNV, overseeing capital project budgeting and forecasting, design approvals, and posting of facilities in GIS.

I was promoted to Director of Operations for Great Basin in 2018. In that role, I was responsible for all operational aspects of Great Basin, including the transmission system, compressor stations and the LNG Plant.

I have been in my current role of Vice President / Northern Nevada Division since 2023, with responsibility for all NNV operations.

**AFFIRMATION OF CHRISTOPHER R. ANDERSON**

Pursuant to NAC 703.710, Christopher R. Anderson affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this _15th day of September, 2025

Chris Anderson

CHRISTOPHER R. ANDERSON

Exhibit 6

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY
CHRISTOPHER M. BROWN

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 17, 2025

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Christopher M. Brown

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Christopher M. Brown. My business address is 8350 S. Durango Drive, Las Vegas, Nevada 89113.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Regulation & Gas Resources departments. My title is Director/Regulation & Gas Resources.

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and professional experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (Commission).

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 The purpose of my prepared direct testimony is to provide an overview of the Company's Nevada Triennial Resource Plan (Resource Plan), discuss the estimated customer rate impacts of proposed investments and activities planned during the action plan period[1], and to outline the Company's proposed cost recovery including its request for deferred accounting for two new programs: the Natural Gas Alarm Pilot Program (Pilot Program) and the Meter Protection Program, and the continuation of deferred accounting treatment and cost recovery for its Customer Owned Yard Line (COYL) Replacement Program through the end of 2028. Finally, I support the new tariff sheets included as Exhibit 2 to the application that outline the Pilot Program and Meter Protection Programs.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My prepared direct testimony consists of the following key points:

- An overview of the Company's Resource Plan;
- A summary of the estimated impact of the investments and activities planned by the Company on the rates charged to its customers and proposed cost recovery; and,
- The Company's request to establish deferred accounting treatment and cost recovery for the Pilot Program, Meter Protection Program and continued deferred accounting treatment of the COYL Replacement Program.[2]

## II. RESOURCE PLAN OVERVIEW

**Q. 7 Please provide an overview of the Company's Resource Plan.**

A. 7 The Company's Resource Plan is filed consistent with the proposed regulation filed by the Commission with the Legislative Counsel Bureau in Docket No. 23-

[1] The Draft Regulations define "action plan period" as the three-year period immediately following the date on which a resource plan is filed with the Commission.

[2] The Commission approved the joint petition filed by the Company and the Regulatory Operations Staff of the Commission in Docket No. 21-08003 which grants the Company authority to defer the program costs associated with capital expenditures for recovery in rates at a later time. See the Commission's Order in Docket No. 21-08003 dated January 11, 2022, at page 2.

07024 on November 25, 2024 (Proposed Regulation). The contents of the Resource Plan include those items outlined in the "NAC 704.XXXX Contents of resource plan" section of the Proposed Regulation. In addition to my testimony, several Company witnesses provide prepared direct testimony supporting various components of the Resource Plan, including:

- Carla D. Ayala, who supports the Company's forecasting methodology and approach, including anticipated natural gas demand information for the forecast period[3];
- Laura Spurlock, who supports the Company's resource planning process;
- Valeria S. Annibali, who supports the Company's proposed nongeologic gas related activities, including Renewable Natural Gas (RNG) and responsibly sourced or transported natural gas (RSG)[4] procurement activities, as well as support for the proposed Demand-Side Management (DSM) plan;
- Thomas W. Cardin and Christopher R. Anderson, who provide testimony supporting the Significant Operational or Capital Requirements[5] Projects

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[3] Per NAC 704.9557 of the Draft Regulations, "Forecast period" means the 9 gas-year period beginning with the gas year immediately following the gas year in which the resource plan is filed.

[4] RSG as referenced herein refers to responsibly sourced carbon capture and storage (CCS)-enabled natural gas as detailed in the prepared direct testimony of Company witness Valeria S. Annibali.

[5] The Draft Regulations define "Significant operational or capital requirements" as follows:

> "NAC 704.XXXX "Significant operational or capital requirements" defined. (NRS 703.025, 704.210, 704.991)
>
> "Significant operational or capital requirements" means:
> 1. The construction of a new transmission, distribution, compression or storage facility or the rehabilitation, replacement, modification, upgrade, uprate or update of existing facilities, or any planned series of such activities addressing the same need, in which the anticipated cost exceeds $5 million; or
> 2. The construction of a single extension facility with 2,000 or more new customers or with a forecasted maximum annual load over the next five years, commencing with the first year following the year when the resource plan or amendment is filed, that is greater than two percent of the gas utility's forecasted load during the first year
> following the year when the resource plan or amendment is filed; or

planned for Southern and Northern Nevada during the action plan period; and,

- Kevin Lang supports the Company's proposed replacement and safety-related programs from a pipeline safety perspective.

**Q. 8 Do the Proposed Regulation identify any actions a gas utility must take prior to filing its Resource Plan?**

A. 8 Yes. Pursuant to section "NAC 704.XXXX Gas utility to meet with interested parties", of the Proposed Regulation:

> *"The gas utility shall meet with personnel from the Commission, the Bureau of Consumer Protection in the Office of the Nevada Attorney General, and any other interested persons no less than 4 months before filing a plan pursuant to NAC 704.961, and not less than 60 days prior to filing any amendment to such plan, to provide an overview of the anticipated filing or amendment."*

**Q. 9 Did the Company meet with the interested parties as required in the Proposed Regulation?**

A. 9 Yes. The Company held a meeting on April 18, 2025 with interested parties to present a high-level overview of the anticipated contents of its Resource Plan, based on the information available at that time.

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3. Any long-term arrangement that results solely from a gas utility's request for incremental upstream resources from an interstate pipeline that requires the interstate pipeline to obtain approval from the Federal Energy Regulatory Commission to construct incremental facilities to meet the gas utility's projected demand; or
4. Investment in infrastructure that facilitates the introduction of nongeologic gas, including biogas, renewable natural gas, or hydrogen gas into the gas utility's system. "Biogas" has the meaning ascribed to it by NRS 704.9992 and "renewable natural gas" has the meaning ascribed to it by NRS 704.9995."

## III. ESTIMATED CUSTOMER RATE IMPACTS

**Q. 10 What estimated customer rate impact information is required for inclusion in the Resource Plan pursuant to the Draft Regulation?**

A. 10 Subsection 7 of the "NAC 704.XXXX Contents of resource plan" section of the Draft Regulations requires that the Resource Plan include "An analysis of the estimated impact of the investments and activities planned by the gas utility on the rates charged to customers." In compliance with this requirement, the Company provides separate information for the Southern and Northern Nevada rate jurisdictions, summarizing the estimated rate impacts of the various investments and activities outlined in the Resource Plan. A summary of the estimated customer rate impacts and illustrative customer bill impacts are provided in Appendix C of the Resource Plan.

**Q. 11 Please provide an overview of the methodology the Company used to estimate customer rate impacts associated with the Significant Operational or Capital Requirements [6] planned, and new programs proposed, by the Company through the action plan period.**

A. 11 To estimate the potential customer rate impacts of Significant Operational or Capital Requirements and new programs proposed during the action plan period, the Company estimated the annual revenue requirement associated with each using the estimated costs provided in the testimonies of Company witnesses Thomas W. Cardin and Christopher R. Anderson for Southern and

[6] See the prepared direct testimony of Company witnesses Thomas W. Cardin and Christopher R. Anderson for information regarding "Significant Operational or Capital Requirements" Projects in Southern and Northern Nevada, respectively.

Northern Nevada, respectively,[7] and the Commission authorized depreciation rates and pre-tax rate of return.[8] The estimated per therm rate impact for each of those projects was then derived using the appropriate billing determinants for each rate jurisdiction.[9]

**Q. 12 What is the Company's proposed cost recovery for the Significant Operational or Capital Requirements[10] contemplated in the Resource Plan and discussed in the testimonies of Mr. Cardin and Mr. Anderson?**

A. 12 The Company proposes to recover costs associated with the Significant Operational or Capital Requirements contemplated in the Resource Plan in a future general rate case filed pursuant to NRS 704.110 or through a Commission-approved alternative rate-making plan.[11]

**Q. 13 Please provide an overview of the methodology the Company used to estimate customer rate impacts associated with the proposed RNG and RSG procurement activities discussed by Company witness Valeria S. Annibali.**

A. 13 To evaluate the potential customer rate impacts resulting from the proposed RNG and RSG procurement activities, the Company applied the established methodology for calculating it Base Tariff Energy Rate (BTER), which constitutes one of the two components of its gas cost rates.

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[7] *Id.*
[8] Approved by the Commission in Docket No. 23-09012.
[9] For purposes of the illustrative rate impacts, the full margin sales volumes for the twelve months ended June 2025 were used for both the Northern and Southern Nevada rate jurisdictions.
[10] New Single Extension Facilities Projects, System Integrity Projects, Distribution Integrity Management Projects and Transmission Integrity Management Projects.
[11] Senate Bill (SB) 417 (2025) requires the Commission to adopt regulations governing the filing of an application for the establishment of an alternative rate-making plan by a natural gas utility. The Commission opened a rulemaking to amend, adopt and/or repeal regulations in accordance with SB 417 in Docket No. 25-07006.

The Company modeled three scenarios:

1. Exclude all RNG and RSG gas procurement activities;
2. Include RNG procurement for 1.99% of its forecasted normal weather sales demand; and
3. Include RSG procurement activities for 5% of its forecasted normal weather sales demand.

The comparative results of these scenarios were used to estimate the impact on the BTER and customer bills.[12]

Although the gas cost rates are comprised of both the BTER and the Deferred Energy Account Adjustment (DEAA)[13], the Company isolated its analysis to the BTER component as it yields a clearer comparison of short-term rate impacts that Southwest Gas sales customers may experience.

**Q. 14 Why do you believe excluding the DEAA component of the gas cost rate from the estimated customer rate and bill impact analysis related to RNG or RSG procurement activities provides a clearer comparison of estimated short-term rate differences?**

A. 14 The DEAA rate reflects the balancing account portion of the gas cost rate and is subject to adjustment pursuant to Nevada Revised Statutes (NRS) 704.110, which prescribes specific tolerances governing the extent and timing of such adjustments, including circumstances under which the DEAA rate must be set to zero.[14] A potential scenario exists wherein forecasted account balances inclusive of RNG or RSG purchases fall within these tolerances, requiring the

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[12] Estimated BTERs are derived using August 6, 2025, Forward Market Prices and assumes forecasted normal weather sales demands throughout the action plan period.
[13] In accordance with the provisions of the NAC and NRS Chapter 704.
[14] NRS 704.110(8)

DEAA be set to zero, while forecasted account balances exclusive of such purchases may not.[15]

As a result, including the DEAA in the analysis could produce misleading conclusions—suggesting lower total gas cost rates (the combination of the BTER and DEAA) over time despite the cost of RNG and RSG compared to conventional natural gas[16]. Therefore, isolating the BTER provides a clearer way to compare the estimated short-term customer rate impacts associated with each of these procurement activities.

**Q. 15 Did the Company estimate the BTER based on RNG purchases at $25/MMBtu for 1.99% of the Company's forecasted normal weather sales demand, and provide an illustrative customer bill comparison against a scenario where equivalent conventional natural gas spot market purchases are made?**

A. 15 Yes. The Company included an illustrative customer bill estimating the BTER, assuming it purchases RNG at $25/MMBtu for 1.99% of its forecasted normal weather sales demand. This is compared to an estimated customer bill based on equivalent conventional natural gas spot market purchases. Please refer to Figure J.2 in the Resource Plan for the illustrative comparison.

. . .

. . .

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[15] This scenario is more plausible to exist when considering the current credit DEAA rates applicable to both Northern and Southern Nevada jurisdictions. In Docket No. 25-05009, the Commission approved Stipulation granted Southwest Gas authority to implement a credit per therm DEAA rate of ($0.20000) and ($0.25000) in Southern and Northern Nevada, respectively.

[16] See the prepared direct testimony of Company witness Valeria S. Annibali.

**Q. 16 Did the Company estimate the BTER based on RSG purchases for 5% of the Company's forecasted normal weather sales demand, and provide an illustrative customer bill comparison against a scenario where equivalent conventional natural gas spot market purchases are made?**

A. 16 Yes. The Company included an illustrative customer bill estimating the BTER, assuming it purchases RSG for 5% of the Company's forecasted normal weather sales demand at a $0.50/MMBtu premium to spot market conventional natural gas.[17] This is compared to an estimated customer bill based on equivalent conventional natural gas spot market purchases. Please refer to Figure J.3 in the Resource Plan for the illustrative comparison.

**Q. 17 How does the Company propose to recover costs associated with the proposed RNG and RSG procurement activities discussed by Company witness Valeria S. Annibali?**

A. 17 The Company proposes to recover costs associated with the proposed RNG and RSG procurement activities in the same manner in which it recovers costs of conventional natural gas purchases. If approved by the Commission, the proposed RNG and RSG purchases would be recorded to the FERC Account 191 for the rate jurisdiction which the RNG and RSG purchases were made, and those purchases would be contemplated in the Company's quarterly gas cost

[17] See the prepared direct testimony of Company witness Valeria S. Annibali for details for regarding the $0.50/MMBtu (2025$) premium associated with RSG purchases compared to conventional natural gas spot market purchases. Analysis assumes that premium escalates annually with the CPI throughout the action plan period.

adjustment filings, and would be reviewed for prudency in the appropriate Annual Rate Adjustment (ARA) application.

**Q. 18 Did the Company estimate customer rate impacts associated with any other programs and provide illustrative customer bill impacts that include the estimated costs of those programs?**

A. 18 Yes. An estimated customer rate impact and illustrative customer bill impact is provided for the Pilot Program (Southern and Northern Nevada), the Meter Protection Program (Northern Nevada only), the COYL Replacement Program (Southern and Northern Nevada), and the DSM Program (Southern and Northern Nevada).

The estimated customer rate impacts and illustrative customer bill impacts for the Pilot Program, Meter Protection Program and COYL Replacement Program are derived using the cost estimates provided by Company witnesses Thomas W. Cardin and Christopher R. Anderson for Southern and Northern Nevada, respectively. Estimated monthly deferral amounts for each program are then provided throughout the action plan period, and the estimated cumulative deferral amount for each program at December 2028 is used to develop an illustrative rate assuming that total cumulative deferral amount would be requested for recovery in a future general rate case filing or pursuant to an alternative rate-making plan filing[18], as approved by the Commission at a later date, for cost recovery over a two-year amortization period.[19]

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[18] Senate Bill (SB) 417 (2025) requires the Commission to adopt regulations governing the filing of an application for the establishment of an alternative rate-making plan by a natural gas utility. The Commission opened a rulemaking to amend, adopt and/or repeal regulations in accordance with SB 417 in Docket No. 25-07006.

[19] The Commission approved Stipulations in the Company's last two general rate case proceedings include two-year amortization periods (Docket Nos. 21-09001 and 23-09012).

The estimated customer rate impact and illustrative customer bill impact for the DSM Program includes the estimated Base Program Rate component of the Conservation and Energy Efficiency (CEE) rate (excludes the balancing account portion of that rate). The estimated Base Program Rate is derived by simply dividing the DSM Program budgets as shown in Appendix B of the DSM Plan included in this application by the appropriate billing determinants. This is consistent with the current methodology used for the Company's approved CEE programs.

The estimated customer rate impacts for each program in the Resource Plan are illustrative and are subject to change depending upon the actual amounts deferred and considered for recovery at the time of the Company's next applicable filing[20], and where applicable, the amortization period that the Commission may approve in a future general rate case application.

## IV. DEFERRED ACCOUNTING TREATMENT / COST RECOVERY

**Q. 19 For which programs is the Company requesting Commission approval for deferred accounting treatment in this application?**

A. 19 Southwest Gas seeks Commission approval to establish deferred accounting treatment for two new programs: the Pilot Program and the Meter Protection Program. The Company also seeks to continue deferred accounting treatment for its COYL Replacement Program through the end of 2028.

**Q. 20 Please provide a high-level overview of each program for which the Company is seeking deferred accounting treatment.**

[20] The Company assumes all deferred amounts would be recovered at a later date through either a general rate case or alternative rate-making plan filing, as approved by the Commission at a later date.

A. 20 Pilot Program

The proposed Pilot Program is a new, 3-year safety-related program through which the Company would purchase, distribute and install natural gas alarms to customers in its Southern and Northern Nevada service territories. The total estimated cost of the Pilot Program in Northern Nevada is approximately $178K in 2026, $82K in 2027 and $82K in 2028.[21] Similarly, in Southern Nevada, the total estimated cost of the Pilot Program is estimated to be approximately $1.245M in 2026, $572K in 2027 and $572K in 2028.[22]

Meter Protection Program

The Meter Protection Program is a Northern Nevada only program in which the Company proposes to install structurally engineered shelters, on existing, unprotected customer meters in heavy snow load areas where the meter is located on the eave-side of the house, in efforts to help protect natural gas meters from snow and ice loading damage. The total estimated cost of the new Meter Protection Program is estimated to be $200K in 2026, $1M in 2027 and $1M in 2028.[23]

COYL Replacement Program

Southwest Gas' COYL Replacement Program allows the Company to replace residential and public school COYLs in both its Northern and Southern Nevada service territories. The Commission approved regulatory asset treatment for the

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[21] See Company witness Christopher R. Anderson's prepared direct testimony for the estimated Northern Nevada Natural Gas Alarm Pilot Program costs by year.

[22] See Company witness Thomas W. Cardin's prepared direct testimony for the estimated Southern Nevada Natural Gas Alarm Pilot Program costs.

[23] See Company witness Christopher R. Anderson's prepared direct testimony at Table 8 for the Northern Nevada estimated Meter Protection Program costs by year.

COYL Replacement Program-related costs and established a program end date of June 30, 2027. [24]

**Q. 21. Please provide an overview of the Company's proposal related to the COYL Replacement Program.**

A. 21 As discussed in the prepared direct testimonies of Company witnesses Thomas W. Cardin and Christopher R. Anderson, Southwest Gas requests authorization to continue the currently authorized COYL Replacement Program as designed, including the level of program cost of approximately $5 million per year (~$3 million for Southern Nevada and ~$2 million for Northern Nevada[22]) and associated cost recovery.

**Q. 22 Please provide a summary of the COYL Replacement Program cost recovery currently authorized.**

A. 22 The currently authorized cost recovery for the COYL Replacement Program, as approved by the Commission in 21-08003, includes the deferral of program costs including the capital, depreciation, and carrying charges consistent with the Company' authorized rate of return.

**Q. 23 Please summarize the Company's proposal related to the continuation of the COYL Replacement Program.**

A 23 The Company seeks Commission approval through this application to continue the COYL Replacement Program through the 2026-2028 action plan period and because program success is subject to customer acceptance, requests the ability to shift approved spend levels between the Northern Nevada and Southern Nevada rate jurisdictions, while maintaining the statewide annual

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[24] See the Commission's Order in Docket No. 21-08003 dated January 11, 2022, at page 3.

program cost of $5 million. This will allow the Company to manage the statewide spend within the Commission-authorized annual program cost while providing flexibility to continue to fund COYL replacements within the state without requiring authorization of reallocation of authorized spend levels by rate jurisdiction.

**Q. 24 Please summarize the Company's request for deferred accounting treatment in this application.**

A. 24 The Company seeks Commission approval pursuant to NRS 704.185(2)[25] to defer costs - including capital, depreciation, and carrying charges consistent with the Company' authorized rate of return, for the Pilot Program, Meter Protection Program and COYL Replacement Programs, in separate regulatory asset accounts. The Company also seeks Commission authority in this application for the ability to present costs deferred to each of those regulatory asset accounts for future recovery in its next applicable general rate case or alternative rate making filing, as may be authorized by the Commission at a later date. The Company is not seeking deferred accounting treatment for the proposed 1984/1985 Pipe Replacement Program in Southern Nevada and will include related costs for recovery in a future general rate case filed pursuant to NRS 704.110 or through a Commission-approved alternative rate-making plan[26].

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[25] NRS 704.185(2) states that "A public utility which purchases natural gas for resale may request approval from the Commission to record upon its books and records in deferred accounts any other cost or revenue which the Commission deems appropriate for deferred accounting and which is not otherwise subject to the provisions of subsection 1. If the Commission approves such a request, the Commission shall determine the appropriate requirements for reporting and recovery that the public utility must follow with regard to each such deferred account."

[26] Senate Bill (SB) 417 (2025) requires the Commission to adopt regulations governing the filing of an application for the establishment of an alternative rate-making plan by a natural gas utility. The Commission opened a rulemaking to amend, adopt and/or repeal regulations in accordance with SB 417 in Docket No. 25-07006.

**Q. 25 Is the Company seeking approval from the Commission in this application to implement a new rate to recover costs associated with the Pilot Program, Meter Protection Program, or COYL Replacement Programs?**

A. 25 No. The Company is not seeking to implement a new rate to recover costs associated with the aforementioned programs. Southwest Gas is simply seeking approval from the Commission in this application to defer and recover costs as described in Q&A 24.

**Q. 26 Are each of the programs for which the Company is seeking deferred accounting treatment in in this Application in the public interest?**

A. 26 Yes. As outlined in Q&A 20 above, as well as more thoroughly detailed in the prepared direct testimony of Company witness Kevin M. Lang, each of the programs for which the Company is seeking deferred accounting treatment support enhanced public safety and are in the public's interest.

**Q. 27 Is the Company seeking to establish a rate for its DSM Program in this application?**

A. 27 No. The Company is not seeking to establish a rate for its DSM Program in this application. Consistent with the Draft Regulations, and consistent with NAC 704.9714(3) of the Proposed Regulation, the Company intends to continue to track costs associated with its DSM Program[27] and present those costs for recovery through its existing CEE rate at the time the Company files its

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[27] The Company's most recent CEE Program budgets and programs were approved in the Commission approved Stipulation in Docket No. 24-06037.

applicable Annual Rate Adjustment application.[28] Pursuant to Subsection 7 of the "NAC 704.XXXX Contents of resource plan" section of the Draft Regulations, an estimated impact of the planned DSM activities on the rates charged to customers is included in Appendix C of the Resource Plan.

## V. CONCLUSION

**Q. 28 Does this conclude your prepared direct testimony?**

A. 28 Yes.

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[28] NAC 704.116(3) states that:
"A gas utility that makes quarterly adjustments to its base tariff energy rate pursuant to subsection 8 of NRS 704.110 shall file an annual rate adjustment application with the Commission for each of its jurisdictional operating departments in this State. Except for a gas utility that makes quarterly adjustments to its deferred energy accounting adjustment, the application must set forth the annual adjustment to the deferred energy accounting adjustment. The annual rate adjustment application must be filed not later than the date specified by the Commission pursuant to subsection 3 of NAC 704.161."

# SUMMARY OF QUALIFICATIONS
# CHRISTOPHER M. BROWN

I hold a Bachelor of Science degree in Civil Engineering from the University of Nevada Las Vegas and a Master of Science in Engineering from Purdue University. I am a licensed professional engineer in the State of Nevada.

From 2001 to 2004, I was employed at Martin and Peltyn Structural Engineers in Las Vegas, Nevada. My primary responsibilities as an engineering designer included performing both gravity and lateral analysis and design for concrete, steel and wood structures.

In June 2004, I began working at The WLB Group, Inc in Henderson, Nevada. My primary responsibilities as a civil engineering designer included the preparation of hydrology and hydraulic analysis as well as utility and roadway design for various commercial, residential, industrial and public works projects.

From 2005 to 2007, I was employed at Wright Engineering in Las Vegas, Nevada as a Project Manager. My primary responsibilities included oversite of hydrologic and hydraulic analysis as well as the preparation of civil improvement plans and tentative maps.

From 2007 to 2009, I worked for Kennedy Commercial in Las Vegas, Nevada. As the Director of Construction my primary responsibilities included overseeing day-to-day construction aspects for multiple commercial and mixed-use construction projects, preparing budgets, selecting consulting engineering firms, and contract negotiations.

In 2009, I joined Aptus Architecture in Las Vegas, Nevada. In my role as the Director Engineering Operations I was responsible for starting a Civil Engineering division of the company. During my time at Aptus, I oversaw all hydrology and hydraulic modeling, technical drainage study preparation, civil improvement plan preparation and business development.

In January 2011, I joined Southwest Gas Corporation (Southwest Gas) in the Southern Nevada Division. As a Distribution Engineer in the New Business group, I was involved with the Strip Reliability Projects, hydraulic analysis and modeling, as well as the design of multiple large meter set assemblies and regulator stations. In January 2012, I moved to the Pipeline Safety/Code Compliance group where I served as the southern Nevada division's engineering key contact for the Transmission Integrity Management Program. In November 2012, I was promoted to Supervisor of the Nevada Key Account Management group where I was responsible for the coordination and management of multiple large customer accounts and design projects. I was subsequently promoted in April 2014 to the Manager of Gas Purchases and Transportation. My responsibilities included soliciting and contracting for the gas supply and transportation resources required to meet the needs of Southwest Gas' sales customers. I was also responsible for nominations and confirmations of gas supplies on upstream interstate pipelines and the confirmation of all gas supplies at the various delivery points that feed into Southwest Gas' distribution system. In January 2020, I moved to Manager/Regulation and Energy and Efficiency where I was responsible for providing guidance consistent with the Company's regulatory initiatives and assisting with the Company's Nevada regulatory activities. In 2021, I was promoted to Director/Regulation where I provided strategic leadership, guidance, and direction in the alignment of the Company's regulatory strategy, ensured technical accuracy, and regulatory compliance, as well as ensured the Company maintained positive relationships with regulatory stakeholders. In March 2024, my title changed to Director/Regulation and Gas Resources with oversight of Gas Supply, Resource Planning and Analysis, and Demand Planning and Analysis moving under my purview.

**AFFIRMATION OF CHRISTOPHER M. BROWN**

Pursuant to NAC 703.710, Christopher M. Brown affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 11th day of September, 2025

CHRISTOPHER M. BROWN

Exhibit 7

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY

OF

CARLA D. AYALA

ON BEHALF OF

SOUTHWEST GAS CORPORATION

September 17, 2025

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Prepared Direct Testimony
of

Carla D. Ayala

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Carla D. Ayala

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Carla D. Ayala. My business address is 8360 S Durango Dr, Las Vegas, NV 89113.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Demand Planning & Analysis department. My title is Manager/Demand Planning & Analysis.

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (Commission) and provided written testimony to the Arizona Corporation Commission and the California Public Utilities Commission.

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 The purpose of my testimony is to support the Demand Planning activities outlined in the Company's Nevada Triennial Resource Plan (Resource Plan), including the forecast of base growth for the forecast period, forecast of sales volumes under normal weather conditions for each month of the forecast period, forecast of the annual peak demand under weather conditions at maximum design conditions as well as the comprehensive description of and justification for the gas utility's forecast methodology.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My prepared direct testimony consists of the following:

- Support for the anticipated demand for natural gas made on the system of the gas utility by its customers including forecast of base growth, forecast of sales volumes under normal weather conditions for each month, and forecast of the annual peak demand under weather at maximum design conditions for the forecast period[1]; and
- A comprehensive explanation and justification for the forecasting methodology used to develop the forecasts.

**II. THE ANTICIPATED DEMAND FOR NATURAL GAS MADE ON THE SYSTEM OF THE GAS UTILITY BY ITS CUSTOMERS INCLUDING FORECAST OF BASE GROWTH, FORECAST OF SALES VOLUMES UNDER NORMAL WEATHER CONDITIONS FOR EACH MONTH AND THE FORECAST OF THE ANNUAL PEAK DEMAND UNDER**

[1] The following terms as used herein are defined consistent with the definitions provided in the draft regulations provided to the Legislative Counsel Bureau (LCB) on November 25, 2024 in Docket No. 23-07024 (Draft Regulations):

> **NAC 704.9555 "Forecast of base growth" defined. (NRS 703.025, 704.210, 704.991)** "Forecast of base growth" means a forecast of the load on a utility's system based on normal weather conditions and the most likely set of future conditions or forces which would have an effect on that load, including *energy efficiency and* conservation induced by price, *energy efficiency and* conservation resulting from laws and regulations and governmental programs, and *energy efficiency and* conservation resulting from existing *demand-side management* programs sponsored by utilities.
>
> **NAC 704.9557 "Forecast period" defined. (NRS 703.025, 704.210, 704.991)** "Forecast period" means the 9 gas-year period beginning with the gas year immediately following the gas year in which *the resource plan is filed.*
>
> **NAC 704.958 "Normal weather conditions" defined. (NRS 703.025, 704.210, 704.991)** "Normal weather conditions" means the average weather conditions for the previous 30 years or another period, if justified.
>
> **NAC 704.9605 "Weather at maximum design conditions" defined. (NRS 703.025, 704.210, 704.991)** "Weather at maximum design conditions" means the coldest day on record for the previous 30 years or another period, if justified.

**<u>WEATHER AT MAXIMUM DESIGN CONDITIONS FOR THE FORECAST PERIOD, AND JUSTIFICATION FOR THE GAS UTILITY'S FORECASTING METHODOLOGY.</u>**

**Q. 7 Did the company provide a forecast of sales volumes under normal weather conditions for each month of the forecast period and the forecast of the annual peak demand under weather at maximum design conditions for the forecast period in its filing?**

A. 7 Yes, the Company includes customer growth projections, monthly sales volumes under normal weather conditions, and extreme peak day demand forecasts for the forecast period in Section C the Resource Plan.

**Q. 8 Please summarize the methodology used to forecast customer growth, forecast sales volumes under normal weather conditions for each month, as well as the forecast the annual peak demand under weather at maximum design conditions.**

A. 8 Customer growth forecasts are developed for each of the Company's seven Nevada operating districts. These include the six Northern Nevada districts Tahoe, Carson Elko & Spring Creek (combined) Winnemucca and Fernley. One combined Southern Nevada district encompassing Mesquite & Southern Nevada. The forecasts are based on an analysis of both short- and long-term trends, supplemented by input from Southwest Gas' Energy Solutions department, whose personnel provide local knowledge of regional development and housing activity.

Monthly demand under normal weather conditions is forecasted by combining the daily use per customer regression equations, the normal weather assumptions, and the forecasted monthly customer counts.

Peak day demand under weather at maximum design conditions (also referred to as design day conditions herein) is forecasted using the same daily use per customer regression equations, but with extreme weather assumptions.[2] This approach is designed to ensure system reliability under rare but severe weather events.

**Q. 9 Did the Company provide a comprehensive description and justification for its forecasting methodology and can you summarize the methodology?**

A. 9 Yes, the Company provides a comprehensive description and justification for its forecasting methodology below and in the Resource Plan that is filed in this docket. As noted in the Resource Plan, the Company's forecasting methodology relies on generally accepted regression-based forecasting techniques to estimate both normal monthly and peak day sales volumes. Regression equations relating historical daily city gate sales deliveries per customer to heating degree days (HDDs) are estimated for the operating districts in both Northern and Southern Nevada. The estimated regression equations are used in conjunction with customer forecasts and HDD assumptions to produce both the monthly normal sales forecasts and design day forecasts. The data sample ranges, and estimated regression equation coefficients capture recent factors such as improved appliance and dwelling efficiencies, price elasticity, and other energy conservation related influences, including building codes and federal appliance standards.

The Extreme Weather Assumption (Extreme HDD) criteria has been consistently used for all the Company's service areas in Nevada, Arizona, and California since 2018. The Extreme HDD is based on the coldest HDD occurrence since 1988.[3] Unlike the ten-year normal HDD, the Extreme HDD is expected to occur only on very rare occasions. The Company discussed the use of Extreme HDD in the Company's Nevada Annual Resource Planning Informational Report

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[2] "Extreme weather" as used throughout my testimony has the same definition as "weather at maximum design conditions" as defined in the Draft Regulations.

[3] The February 1989 cold weather event occurred during the 1988/1989 heating season and is sometimes referenced by either year depending on context.

(Informational Report), Docket No. 18-06006. As discussed in more detail below, in Docket 23-11017, the Company's 2023 Annual Rate Adjustment (ARA) Application[4], the Commission's Order reaffirmed its acceptance of this methodology.[5]

**Q. 10 What HDD assumptions are used to produce the monthly normal sales forecasts?**

A. 10 Southwest Gas has consistently utilized a 10-year average HDD assumption for developing normal monthly long-range demand forecasts and weather normalizing test year heat sensitive sales for general rate cases since at least 1984. This methodology has been accepted by the Commission in every Southwest Gas filing, demonstrating its consistency with established regulatory expectations and practices.

**Q. 11 Over time, how have the normal monthly forecasts previously filed in the Company's Informational Reports[6] compared to Actuals?**

A. 11 The previously filed normal weather forecasts compared to actuals are illustrated in Exhibit No.__(CDA-1) and Exhibit No.__(CDA-2), attached to this testimony, for both Northern and Southern Nevada. These exhibits demonstrate that the forecasts of monthly sales volumes under normal weather conditions have historically tracked closely with actual customer usage across multiple operating districts. The observed alignment between forecasted and actual values provides validation of the inputs used in the forecasting models, such as customer growth projections, regression equations, and weather assumptions. This historical performance reinforces the reliability of the Company's methodology and supports the conclusion that substantially accurate data is used in the Company's long-

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[4] The Company's 2024 ARA Application was settled by the parties.
[5] Docket No. 23-11017 Order at page 12, paragraph 29.
[6] Informational Reports were filed pursuant to Nevada Revised Statues 704.991 and Nevada Administrative Code (NAC) 704.961

range demand forecasts, in accordance with regulatory expectations.

**Q 12 Where does Southwest Gas obtain the data that is used in the Company's forecasts?**

A 12 Southwest Gas utilizes established and reliable data from multiple sources. As discussed in the Resource Plan, the Company collects HDDs from the United States Department of Commerce's National Oceanic and Atmospheric Administration (NOAA). The Company also relies on demographic and economic projections from multiple reputable sources, including the Nevada State Demographer, university-based economic research centers such as the Center for Business and Economic Research (CBER) at UNLV, federal agencies, such as the U.S. Bureau of Labor Statistics and Bureau of Economic Analysis, and private economic research firms such as Wells Fargo and Nevada State Bank. National and regional forecasts are further refined using localized variables including housing permit activity, employment trends, and direct input from experienced Company personnel who monitor local development conditions. Please reference the Resource Plan for further discussion on the Company's forecasting methodology and the data utilized.

**Q. 13 What HDD assumptions are used to produce the design day forecasts?**

A. 13 The Extreme HDD assumption is based on the coldest HDD occurrence since 1988. The Extreme HDD criteria has been consistently used for all the Company's service areas in Nevada, Arizona, and California since 2018. Unlike the ten-year normal HDD, the extreme HDD is expected to occur only on very rare occasions.

**Q. 14 What was the Company's Extreme HDD criteria prior to 2018?**

A. 14 Prior to 2018, Southwest Gas utilized the coldest HDD occurrence in the most recent thirty years as the companywide extreme HDD criteria.

**Q. 15 In 2018, why did the Company change the companywide Extreme HDD criteria to the coldest HDD occurrence since 1988?**

A. 15 In 2018 the Company evaluated the feasibility of the continued use of the coldest HDD in the most recent thirty-year period to determine appropriate Extreme HDDs. The results of internal probabilistic assessments indicated that in the absence of severe weather in the next two to four years, the new Extreme HDDs using the coldest HDD in the most recent thirty-years criteria would be less severe. This would increase the risk that these HDDs could be exceeded by subsequent extreme weather events for the Company's weather stations, including the six weather stations utilized in the Southern Nevada and Northern Nevada service areas. The continued use of the coldest HDD occurrence in the most recent thirty years would place the Company at risk of having insufficient resources to serve its customers' extreme weather demands, where customer service interruptions could result in significant public safety issues or property damage. Therefore, the Company changed its extreme weather criteria to maintain the coldest HDD occurrence since 1988 in all its service areas in Nevada, Arizona and California.

**Q. 16 Can you provide additional detail on the probabilistic assessment the company conducted and how those assessments support the continued use of the coldest HDD since 1988?**

A. 16 Yes, as part of the 2018 evaluation, the Company performed probabilistic analyses to determine the likelihood of occurrence for various extreme HDD values. These analyses confirmed that the coldest HDDs from the most recent thirty years no longer represent rare or extreme events. The probabilities of occurrence for the HDDs identified using the coldest in thirty – year criteria range from 0.040149 to 0.20214 for the six Nevada weather stations – frequencies that suggest a much higher chance of recurrence than is acceptable for planning purposes. The probability of occurrence associated with the Company’s current HDD criteria, which uses the coldest observed value since 1988, is significantly lower, ranging from 0.008168 to 0.025225 across the same weather stations. These lower probabilities better reflect the nature of an extreme weather event and appropriately align with the Company's commitment to providing safe and reliable service.

**Q. 17 What steps does the Company take to validate the reasonableness of the design day forecasts?**

A. 17 After the regression equation quantifies the relationship between daily demands and HDD, the forecast undergoes a critical reasonableness evaluation by comparing it to actual historical demands. If the forecast significantly deviates from historical data, either overestimating or underestimating demand, the regression coefficient is adjusted to ensure reasonableness. This adjustment involves leveraging both historical data and expert knowledge. While HDDs effectively explain much of the variation in historical daily demands, there are additional variables that are harder to quantify and incorporate into regression equations. These factors become particularly relevant during colder weather days. Regression equations perform well in forecasting demands during more typical or normal weather conditions; however, they may not perform as well during atypical colder or extreme events. Failing to adjust the forecast could lead to unreliable results.

**Q. 18 What adjustments does the Company make to its extreme weather forecasts to ensure its regression equations more properly align with anticipated usage?**

A. 18 To ensure that its extreme weather forecasts reasonably reflect the demand that could occur during extreme weather events the Company may apply a scaling factor to the regression coefficient. This adjustment is used when the preliminary forecast, while statistically sound, does not fully account for factors that are difficult to quantify in the regression analysis alone, such as customer behavior during cold weather events.

**Q. 19 Does the Company always scale the regression coefficient when developing extreme peak day demand forecasts for each of its operating districts in Nevada?**

A. 19 No. Given the highly reliable regression diagnostics statistics and the reasonableness of the preliminary forecasts, scaling of the regression coefficient, and adjusting the forecasts is not typically required. However, as described above, and as previously presented and discussed in Docket Nos. 16-06003[7] and 20-05028[8], failing to adjust the forecast would risk understating the actual demand that could occur during severe weather events. This could lead to risks to public safety and property damage during periods of extreme cold. Therefore, the use of a scaling factor is an important step in the Company's validation process to ensure that demand forecasts are realistic and capable of maintaining safe and reliable service for customers under severe weather conditions.

**Q. 20 Is it common to add a qualitative or judgmental component to the regression equation forecasts to develop forecasts in an applied business forecasting environment?**

A. 20 Yes. Although not all forecasts require a qualitative or judgmental component, it is recognized that adding a qualitative or a judgmental component is required in instances to develop a forecast that will pass the reasonableness or common sense test. Dr. James R. Evans, PhD, a professor at the University of Cincinnati provides a summary of this applied forecasting best practice in his textbook, Statistics, Data Analysis, and Decision Modelling (Pearson Prentice Hall, New

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[7] See the prepared Rebuttal Testimony of Company witness James L. Cattanach in Docket No. 16-06003 at pages 2-9.

[8] See the prepared direct testimony of Company witness James L. Cattanach in Docket No. 20-05028 at page 8

Jersey, 2007, Pages 272-273):

*The Practice of Forecasting*

> In practice, managers, use a variety of judgmental and quantitative forecasting techniques. Statistical methods alone cannot account for such factors as sales promotions, unusual environmental disturbances, new product introductions, large one-time orders, and so on. Many managers start with a statistical forecast and adjust it to account for intangible factors. Others may develop independent judgmental and statistical forecasts then combine them, either by averaging or in a subjective manner. It is impossible to provide universal guidance as to which approaches are best, for they depend on a variety of factors, including the presence or absence of trends, and seasonality, the number of data points available, length of the forecast time horizon, and the experience and knowledge of the forecaster. Often, quantitative approaches will miss significant changes in the data, such reversal of trends, while qualitative forecasts may catch them, particularly when using indicators as discussed earlier in this chapter.

**Q. 21 Has the Company recently provided support for its forecasting methodology, including its use of scaling factors and its use of a period of 30 years or more for its extreme HDD peak design in previous dockets before the Commission?**

A. 21 Yes. The Company has consistently presented support for its forecasting methodologies in multiple dockets, which have previously been accepted by the Commission. Most recently, the Company presented information supporting its forecasting methodologies in its 2019, 2020, 2021 and 2023 ARA applications (Docket Nos. 19-06003, 20-05028, 21-11011 and 23-11017). Moreover, the Company has provided similar information supporting the Company's forecasting methodologies in Docket No. 19-12019.[9]

**Q. 22 Has the Commission previously found the Company's forecasting methodology improper?**

A. 22 No. The Commission found, in the Company's 2019 ARA application, that it was justified at that time to allow the Company flexibility going forward to use a period

[9] Docket No. 19-12019 is the docket under which the Commission opened an Investigation to determine if Chapter 704 of the NAC needed to be amended to allow for review of long-term gas procurement contracts. See the Company's comments filed on April 14, 2021, March 31, 2022 and August 18, 2022.

beyond 30 years when considering weather at maximum design conditions under Nevada Administrative Code NAC 704.9605.[10]

In the Company's 2021 ARA application filing (Docket No. 21-11011) the Commission found that SWG's October 2020 procurement was conducted using its longstanding forecasting and procurement methods and practices[11]:

In the Company's 2023 ARA application filing (Docket No. 23-11017) the commission stated the following in its Order[12]:

> Pursuant to NRS 704.110(9)(e), when a public utility files an ARA application, the Commission shall not allow the public utility to recover any recorded costs of natural gas which were the result of any practice or transaction that was unreasonable or was undertaken, managed, or performed imprudently by the public utility. Here, the Commission finds that Southwest Gas's procurement of gas during the test period was reasonable and prudent. The Commission acknowledges that the issue of changing or modifying Southwest Gas's forecasting methodologies is already being addressed in Docket No. 19-12019[2]. However, the Commission finds that Southwest Gas's current peak demand forecasting methods are consistent with longstanding procedures and practices.
>
> NAC 704.9605 allows Southwest Gas to use another period rather than the previous 30 years in its forecasting methodologies, if justified. The Commission finds that it is in the public interest for Southwest Gas to use a period other than the previous 30 years in its forecasting methodology because it will reduce the risk of extreme weather events causing significant property damage or loss of life in the relevant service territories. Therefore, the Commission finds that Southwest Gas's use of the February 1989 cold weather event is permissible and justified under NAC 704.9605.

The Company stands by its forecasting methodology and is not aware of any circumstances, since the above-referenced Orders were issued, that would require the Company to deviate from its current and longstanding accepted methodology.

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[10] See the Commission's December 19, 2019 Order in Docket No. 19-06003 at page 32, paragraph 95.
[11] See the Commission's June 7, 2022 Order in Docket No. 21-11011 at page 24, paragraph 58.
[12] See the Commission's June 7, 2022 Order in Docket No. 23-11017 at page 11-12, paragraphs 28-30.

## III. CONCLUSION

**Q. 23 Is the Company's forecasting methodology as described herein justified?**

A. 23 Yes. As described herein and in the Resource Plan, the Company's forecasting methodology is justified and fully aligns with the regulatory requirements under the applicable Resource Planning regulations. Southwest Gas utilizes accurate and up to date data from reliable sources including data from federal, state, county and local agencies, universities, and reputable private sources. The Company employs recognized and generally accepted regression-based forecasting techniques that are routinely validated through reasonableness reviews to ensure statistical integrity and practical reliability. The Company's forecasting methodologies have been reviewed and approved by this Commission on multiple occasions including recently in Docket Nos. 19-06003, 20-05028, 21-11011 and 23-11017. Additionally, the Company's methodology is consistent with Nevada's broader energy policy objectives. The Governor's Executive Order 2023-07 recognizes that[13]

> Continued investment in Nevada-based energy projects is necessary in order to have a balanced energy portfolio that includes renewable energy resources, low-carbon resources, including natural gas, and the utilization of regional transmission and infrastructure to acquire energy resources is necessary to ensure safe, reliable and affordable delivery of energy statewide.
>
> Natural gas remains an essential part of the state's balanced energy portfolio, and there have been no changes in federal or state policy that necessitate a departure from the Company's longstanding and Commission approved methodology.

The Company's forecasting methodology documents the demographic and economic projections used and cites reputable sources, such as the Nevada State Demographer, university-based research centers, federal agencies, and private economic institutions. These national and regional forecasts are further

[13] See the State of Nevada Executive Order 2023-07 dated March 21, 2023

refined using localized variables including housing permit activity, employment trends, and direct input from Company personnel who monitor local development conditions. This ensures that the final customer growth forecasts accurately reflect economic conditions unique to each operating district.

Federal, state, county, and local policies, such as updated building codes and federal appliance efficiency standards are inherently incorporated into the regression coefficients and customer usage trends. This accounts for ongoing improvements in appliance and dwelling efficiencies, price elasticity, and other energy conservation influences that directly impact natural gas demand.

Finally, the Company's peak design day methodology is justified by using the coldest HDD occurrence since 1988 rather than the coldest day on record for the previous 30 years, the Company appropriately accounts for the possibility of rare but severe weather events. This prudent approach helps safeguard customers by ensuring that the system has sufficient capacity to meet demand even during extreme conditions. Where necessary, the Company adjusts its design day forecasts using a scaling factor to ensure the final projections remain reasonable based on both statistical performance and historical experience.

**Q. 24 Does this conclude your prepared direct testimony in this matter?**

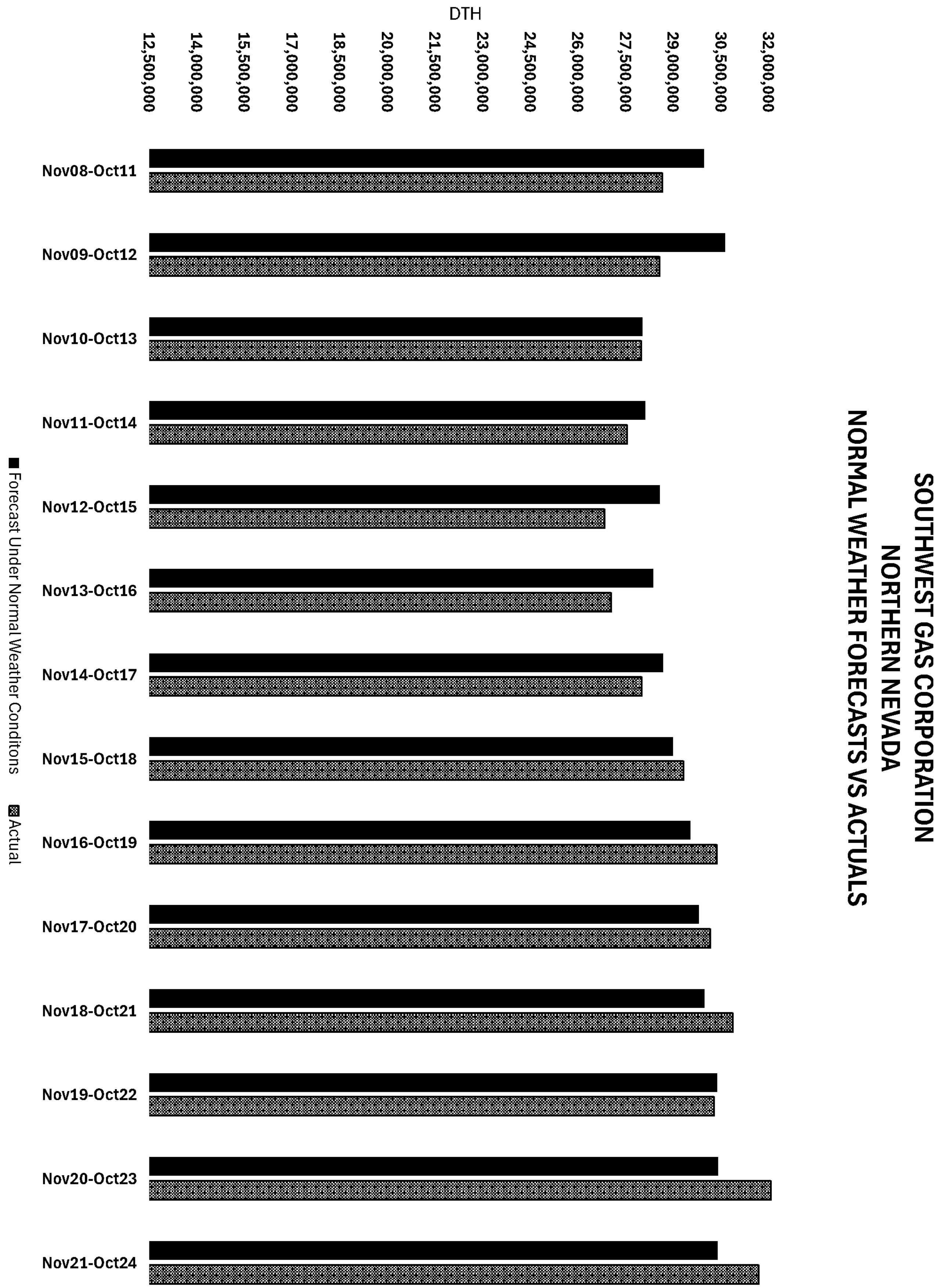
A. 24 Yes.

**SUMMARY OF QUALIFICATIONS**
**CARLA AYALA**

I graduated from New Mexico State University, Las Cruces, New Mexico, with a Bachelor of Arts degree in Economics in 2003. In December 2004, I graduated from New Mexico State University, Las Cruces, New Mexico with a Master of Arts degree in Economics, with a specialization in Public Utility Regulation.

In 2005, I joined Southwest Gas Corporation as an Analyst in the Demand Planning Department. In December 2009, I was promoted to Analyst III/Demand Planning, in November 2013, I was promoted to Economist and in November 2018, I was promoted to Sr Economist. In February 2023, I was promoted to my current position of Manager/Demand Planning & Analysis. I am responsible for overseeing the development of weather normalized billing determinants for rate cases, the development of short- and long-range demand forecasts for rate cases and systems planning, analysis and monitoring of the regional economy in each of Southwest Gas' rate jurisdictions and assorted load research activities.

I have provided testimony to the Public Utilities Commission of Nevada (PUCN), The Arizona Corporation Commission (ACC) and the California Public Utilities Commission (CPUC).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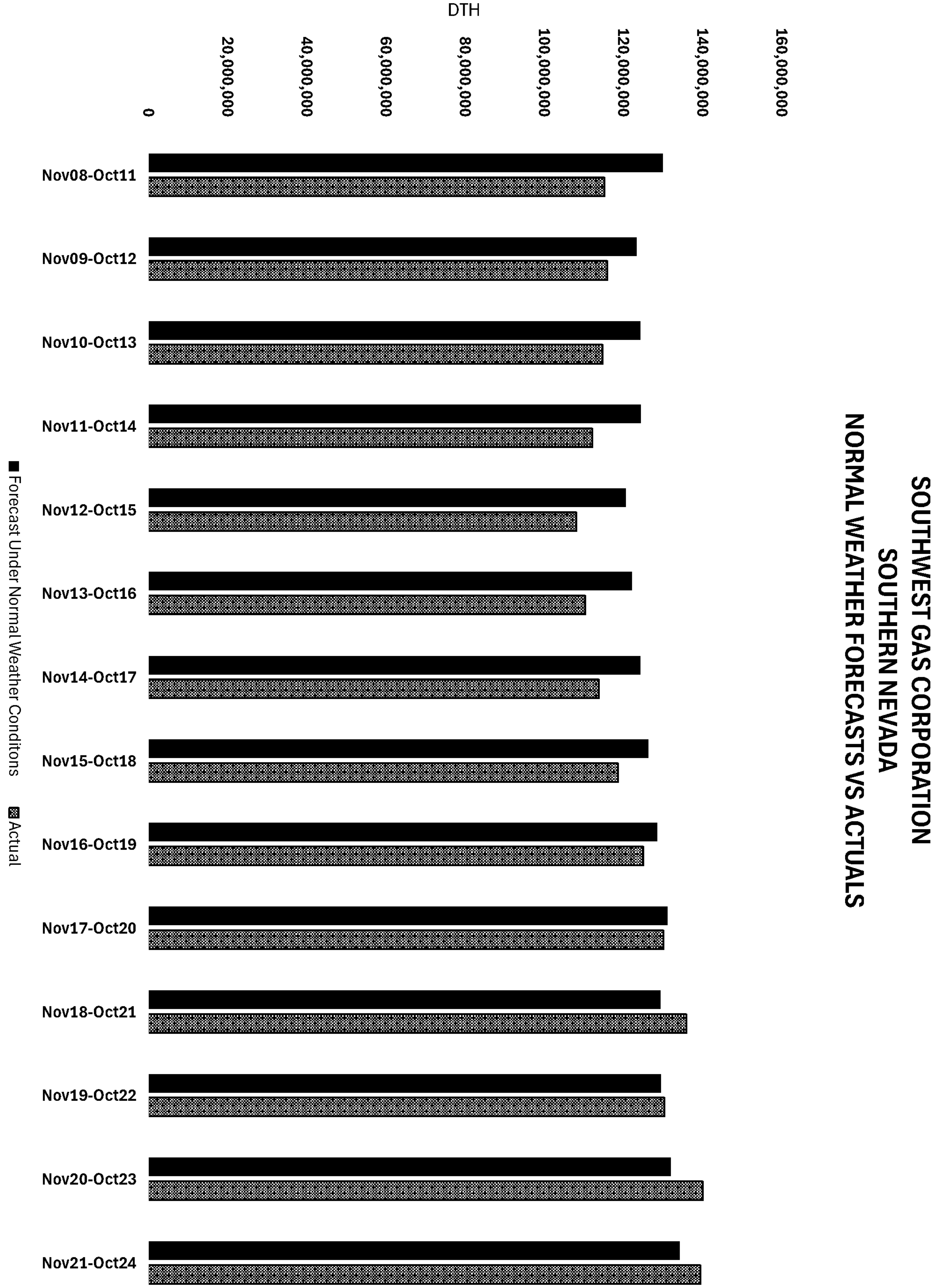
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Nov21-Oct24
Forecast Under Normal Weather Conditons
Actual

## AFFIRMATION OF CARLA D. AYALA

Pursuant to NAC 703.710, Carla D. Ayala affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 12 day of September 2025

Carla Ayala

CARLA D. AYALA

Exhibit 8

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY
OF
LAURA SPURLOCK

ON BEHALF OF
SOUTHWEST GAS CORPORATION

September 17, 2025

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Laura Spurlock

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Laura Spurlock

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Laura Spurlock. My business address is 8360 S Durango Dr., Las Vegas, Nevada 89113.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Resource Planning & Analysis department. My title is Manager/Resource Planning & Analysis.

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (Commission).

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 The purpose of my prepared direct testimony is to describe the process the Company undertakes to plan for and secure incremental long-term upstream transportation and storage resources to ensure safe, reliable, and uninterrupted service for its Northern Nevada and Southern Nevada service areas.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My prepared direct testimony consists of the following:

- A description of the resource planning process the Company follows to acquire long-term upstream transportation and storage resources;
- An overview of the resource planning process that led to the Company's decision to enter into an agreement with Great Basin Gas Transmission Company (Great Basin) to acquire incremental transportation capacity for its Northern Nevada service area as part of Great Basin's 2026 Expansion Project; and,
- An overview of the process the Company is undertaking to acquire incremental long-term upstream transportation and bundled delivered supply resources for its Southern Nevada service area.

## II. SOUTHWEST GAS' RESOURCE PLANNING PROCESS

**Q. 7 What is the primary objective of the Company's long-term resource planning process?**

A. 7 The Company's primary objective is to contract sufficient upstream resources to serve its forecasted extreme weather design day demands and provide safe, reliable and uninterrupted service to its Sales Customers.

**Q. 8 Please describe the customer classes for which the Company acquires sufficient upstream resources necessary to provide service.**

A. 8 The Company acquires sufficient interstate transportation capacity service for all Priority 1 (P1), Priority 2 (P2), and Priority 3 (P3) Sales customers (collectively, Sales Customers)[1]. Sales Customers are typically residential, small commercial, large commercial, and industrial customers who do not qualify for transportation service.[2] In addition to securing interstate capacity service, the Company also acquires natural gas supplies for Sales Customers. The Company does not

[1] The definition of P1, P2 and P3 as used herein is consistent with the priorities in curtailment of service as defined in Nevada Administrative Code (NAC) 704.501.

[2] Requirements for transportation service are outlined in section 1.2 of Schedule No. ST-1/NT-1 of the Company's Nevada Gas Tariff No. 7.

acquire interstate transportation capacity or natural gas supplies for large end-use customers who qualify for and elect transportation service.

**Q 9 In the context of resource planning, what is a resource shortfall?**

A 9 A resource shortfall is where the Company's total contracted firm upstream pipeline[3] transportation, storage, and bundled delivered supply resources are insufficient to serve the Company's forecasted extreme weather design day demands.

**Q. 10 Describe the situations when resource shortfalls could occur?**

A. 10 Resource shortfalls may occur when the forecasted extreme weather design day demands change due to an update in the forecast or when existing contracts for firm resources are due to expire and must be replaced. Southwest Gas uses the long-term planning process to avoid resource shortfalls.

**Q. 11 What planning horizon does the Company typically use in its long-term planning process?**

A. 11 Under normal circumstances, the Company utilizes two planning horizons: a three-year planning horizon and a five-year planning horizon. The three- and five- year planning horizons occur respectively at three years and five years before a forecasted shortfall is expected to occur. If the forecasted extreme weather design day demands abruptly increase and create more immediate short-term shortfalls, evaluations may be expedited to accelerate the resource planning process.

**Q. 12 Why does the Company have both three-year and five-year planning horizons?**

A. 12 The planning horizon is dependent on the current market conditions and the current availability of upstream pipeline transportation resources, bundled delivered supplies and storage resources. If the Company has confidence that

[3] "Upstream pipeline" as used herein has same the meaning as "interstate pipeline", "pipeline," or "upstream interstate pipeline."

resources will be available within three years, the planning horizon may be based on the three-year timeframe. However, if the Company believes there may be limited incremental resources available or resource optionality is limited, or both, the planning horizon will be based on the five-year timeframe. The reason for this is because a pipeline regulated by the Federal Energy Regulatory Commission (FERC) typically takes three to four years to design, obtain the necessary permits, acquire FERC approval, and construct an expansion project.

**Q. 13 Please describe the general process the Company uses to procure the resources needed to meet projected resource shortfalls.**

A. 13 The Resource Planning & Analysis team (RP&A) first identifies the shortfall volumes within a five-gas year window, starting from November 1st of the gas year in which shortfalls begin to occur through October 31st at the end of the five-gas year window. RP&A then works with the Gas Purchases & Transportation team (GP&T) to solicit offers from interstate pipelines and natural gas suppliers for resources via a Request for Proposal (RFP). GP&T then forwards RP&A responsive offers to the RFP for evaluation. In the case of multiple competing offers, RP&A will use the resource optimization software Plexos® to model the best cost portfolio selection of resources. If alternate portfolio scenarios need to be evaluated, a net present value (NPV) analysis is incorporated as a metric to measure cost-effectiveness between the scenarios. RP&A then presents the results of the analysis to GP&T and senior management for review, discussion, and final approval of the selected portfolio of resources. After final approval of the selected portfolio of resources is acquired, GP&T secures contracts for the selected resources.

**Q. 14 Even though the Company follows the same general resource planning process, are there differences in how resources are procured between the Southern Nevada and Northern Nevada service areas?**

A. 14 Yes. Differences in resource acquisitions between the Company's Southern and Northern Nevada service areas are largely due to the availability and the optionality of resources.

**Q. 15 Please explain what you mean by the "availability" and "optionality" of resources with respect to acquisitions.**

A. 15 The availability of resources refers to whether resources are immediately available in the marketplace or require significant lead time to acquire. The optionality of resources refers to the existence of alternatives that can be contracted to meet resource needs.

**Q. 16 Please describe the availability of resources and the optionality of resources in the Company's Southern Nevada service area.**

A. 16 The Southern Nevada service area can be served directly from three different interstate pipelines: Kern River Gas Transmission Company (Kern), Transwestern Pipeline Company (Transwestern), and El Paso Natural Gas Company (El Paso). The combination of Kern, Transwestern and El Paso have demonstrated over decades to be capable and reliable in the transportation, or transmission, of natural gas to Southern Nevada. Gas supplies flowing on Transwestern and El Paso are delivered through Southwest Gas Transmission Company (SGTC), which is an interstate pipeline owned and operated by Southwest Gas, to the Company's Southern Transmission System (STS) which ultimately delivers the resources to the Company's distribution system. While the Company requires deliveries from Kern to serve a large percentage of its Southern Nevada sales demands, a portion of the Company's sales demands must also be served via the

STS.[4] Deliveries received by SGTC, which flow through the STS can come from Transwestern, El Paso, or both. Additionally, there are numerous natural gas suppliers, marketers, or producers with firm capacity rights on these pipelines (excluding SGTC) who can deliver gas supplies directly to Southwest Gas' delivery points in the form of bundled delivered supplies. These circumstances provide the Company with the optionality to evaluate and contract a mix of resources from different entities. Furthermore, because of the optionality of resources in the Southern Nevada service area, there is greater availability of those resources, meaning Southwest Gas can typically acquire those resources with little lead time.

**Q. 17 How does this differ from the availability and optionality of resources in the Company's Northern Nevada service area?**

A. 17 First, the Company's Northern Nevada distribution facilities are not fully reticulated and are dispersed over a wide geographic area, creating smaller, isolated service sub-areas. Second, the sub-areas are primarily fed by a single interstate pipeline, namely Great Basin, through a network of mainline and lateral pipeline facilities. Third, in order to get natural gas supplies to the Company's delivery points, Southwest Gas must contract on interstate pipelines feeding into, or interconnected with, Great Basin. These pipelines are Northwest Pipeline (Northwest), Tuscarora Gas Transmission Company (Tuscarora), and Ruby Pipeline (Ruby). Lastly, because of this structure, bundled delivered supplies are only available at the interconnection points between Great Basin and the three upstream pipelines. Therefore, even though there is some optionality of resources upstream of Great Basin, if Great Basin has no unsubscribed capacity, there is no immediate availability of resources, and Great Basin must go through a lengthy

[4] See the prepared direct testimony of Company witness Kevin M. Lang for specific information pertaining to the safety and reliability of the STS and the prepared direct testimony of Company witness Thomas W. Cardin for specific information pertaining to the STS and any future STS capital work.

process to expand its system to provide the Company with incremental transportation service necessary to meet its forecasted demand. Even though there is typically less optionality in the Northern Nevada service area, the combination of transportation service from Great Basin, Northwest, Tuscarora, and Ruby have historically proven capable and reliable in their ability to serve the needs of Northern Nevada. However, Southwest Gas must account for the FERC process for expansion of transmission facilities when additional capacity is not readily available in Northern Nevada and the Company anticipates the need for additional transportation service.

**Q. 18 Please describe the process the Company undertakes to secure incremental transportation service on a FERC-regulated pipeline that requires an expansion of its facilities.**

A. 18 Initially, the Company identifies the incremental volumes it requires to resolve any shortfalls through a five-year timeframe, as previously described in my testimony. Then, the Company sends these volume requirements to the pipeline(s) with a request for an estimated cost of the facilities the pipeline must construct to provide the incremental service. Once the Company receives the cost estimate(s), it may perform an NPV analysis to determine the best cost option if multiple cost estimates are received from competing pipelines. If the Company makes a decision to move forward, it will execute a Precedent Agreement (PA) with the pipeline obligating the Company to take the service created from the expansion project. The pipeline will then hold an open season, which notifies the public of the project and provides an opportunity for other interested parties to participate. Depending on the results of the open season, the Company may be obligated to take all or a portion of the incremental service. The pipeline then moves forward with preparing and filing an application with FERC requesting authority to expand its facilities and services through a certificate proceeding (CP). The CP may be a lengthy process depending on the scope of the project, the environmental reviews required, and involvement from other stakeholders, such as landowners, affected by the project. Once FERC determines that the pipeline has met all the necessary requirements for the project, it will grant approval for the project to move forward. The pipeline can then begin constructing the facilities needed to provide the incremental service. When the construction of the facilities is completed or nearing completion, the pipeline will execute a transportation service agreement (TSA) with the Company to commence service. The entire process can take three to four years or longer based on the length of time for the FERC CP and the length of time for construction of the facilities.

**Q. 19 Is this process for pipeline expansion projects different between the Company's Southern Nevada and Northern Nevada service areas?**

A. 19 The overall process would be the same. However, the pipelines serving the Company's Southern Nevada service area (Kern, Transwestern, and El Paso), have historically had some available capacity that the Company could simply execute an agreement for without the need for an expansion. Even if an expansion were required on any of the aforementioned pipelines, the Company has the option to contract for bundled delivered supplies, which may be a more cost-effective option than a pipeline expansion. Unlike the Southern Nevada service area, Great Basin is the only interstate pipeline directly serving the Company's Northern Nevada service area. It currently has no available capacity and has a non-existent bundled delivered supply market at the Company's city gates. Consequently, the only option available to the Company for incremental transportation service is an expansion on Great Basin.

**III. SOUTHWEST GAS' INVOLVEMENT IN GREAT BASIN GAS TRANSMISSION COMPANY'S 2026 EXPANSION PROJECT**

**Q. 20 Prior to the Company's participation in the 2026 Expansion Project, did Southwest Gas determine that it had a firm transportation capacity resource shortfall in its Northern Nevada service area?**

A. 20 Yes. In 2023, the Company determined that it would have firm interstate transportation capacity resource shortfalls for its Northern Nevada service area served by Great Basin located south of Great Basin's Elko Lateral. Based on the Company's long-range extreme weather design day sales demand forecast, the capacity shortfalls were projected to occur starting in the 2026/2027 gas year. As discussed in the prepared direct testimony of Company witness Carla D. Ayala, the Commission most recently affirmed its approval of the Company's forecasting methodology in the Company's 2023 ARA Application.

**Q. 21 What Company specific Northern Nevada districts located south of the Elko Lateral does Great Basin's system serve?**

A. 21 The Company's Northern Nevada districts that are served south of Great Basin's Elko Lateral are the Fernley (previously referred to as Fallon), Carson, and Tahoe districts. The Company's approximate 88,000 customers located in these districts (except those located in Lovelock, Nevada) are served from Great Basin's Carson Lateral.

**Q. 22 What interstate resources does the Company rely on to transport gas supplies to its Northern Nevada service area located south of Great Basin's Elko Lateral?**

A. 22 The interstate resources the Company relies on to serve this area are Great Basin contracted transportation capacity rights, contracted storage services from Great Basin's liquified natural gas (LNG) storage facility (located in Lovelock, Nevada), and contracted transportation capacity rights on Tuscarora. Tuscarora transports gas supplies from either the Tuscarora/Gas Transmission Northwest (GTN) interconnect, located near Malin, Oregon, or the Sapphire Mountain interconnect with Ruby, to Great Basin's Wadsworth Junction receipt point for delivery into its Carson Lateral. Great Basin also transports gas supplies to the Company's Northern Nevada service area south of the Elko Lateral from its interconnect with Northwest at the Owyhee receipt point, and its interconnect with Ruby at the Opal Valley receipt point.

**Q. 23 What total volume of incremental firm transportation capacity did the company determine it needed for its Northern Nevada and Northern California service areas?**

A. 23 The Company determined that it needed a total volume of 7,886 Dth/day of net incremental firm transportation capacity to serve both its Northern Nevada (6,821 Dth/day net) and Northern California (1,065 Dth/day net) service areas' projected extreme weather design day sales demands through the 2030/2031 heating season.

**Q. 24 How did the Company address this total resource shortfall?**

A. 24 To address this total resource shortfall, the Company solicited incremental firm transportation capacity from Great Basin.

**Q. 25 What volume of incremental firm transportation capacity did the Company solicit from Great Basin?**

A. 25 The Company solicited 8,129 Dth/day of gross incremental firm transportation capacity, which includes a 3 precent fuel loss, from Great Basin.

**Q. 26 Why did the Company gross up the net shortfall quantities by 3% in its request to Great Basin?**

A. 26 Great Basin's maximum tariff fuel factor is 3% (Section 4.2(d)(1) of the General Terms and Conditions of Great Basin's Tariff). On an extreme weather design day, all of Great Basin's compressor stations would most likely be functioning at their maximum levels. Using the maximum tariff fuel factor is appropriate for the Company's modeling of an extreme weather design day event.

**Q. 27 Did the Company solicit incremental firm transportation capacity from any interstate pipeline other than Great Basin?**

A. 27 No.

**Q. 28 Why didn't the Company solicit incremental firm transportation from interstate pipelines other than Great Basin?**

A. 28 Great Basin is the only pipeline that can geographically serve the Company's service areas with projected shortfalls located on Great Basin's Carson Lateral, including the North Tahoe and South Tahoe Laterals. No other upstream pipeline is able to deliver gas directly to the Company's locations with projected shortfalls.

**Q. 29 At the time of the Company's request, did Great Basin have unsubscribed capacity to meet the Company's incremental resource requirement?**

A. 29 No. Great Basin responded to the Company's request with a cost estimate for a capacity expansion to meet the Company's incremental resource requirement of 8,129 Dh/day (gross).

**Q. 30 If there was no unsubscribed capacity on Great Basin, were there any alternatives the Company had for incremental firm transportation resources other than a pipeline expansion?**

A. 30 No. As mentioned previously, there are no other pipelines with the ability to deliver gas directly to the Company's service areas where shortfalls were projected to occur. Additionally, prior to this expansion, Northern Nevada Sales Customers located along Great Basin's North Tahoe and South Tahoe Laterals were relying on excess contracted capacity available from Southwest Gas' Northern California, North Lake Tahoe, and South Lake Tahoe service areas, respectively. Due to the Company's projected sales demand growth within the Northern California, North Lake Tahoe, and South Lake Tahoe service areas, the excess capacity would no longer be available to address shortfalls for Northern Nevada Sales Customers located along Great Basin's North Tahoe and South Tahoe Laterals during the planning horizon.

**Q. 31 Did Great Basin provide cost estimates based on the Company's requested total incremental firm transportation capacity volume for its Northern Nevada and Southern California service areas?**

A. 31 Yes. Great Basin submitted a cost estimate based on an incremental transportation capacity volume of 8,129 Dth/day (gross).

**Q. 32 Did the Company provide notice to Great Basin that it wished to proceed with the project?**

A. 32 Yes, the Company provided notice to Great Basin that it wished to proceed in May 2023.

**Q. 33 After the Company provided notice that it wished to proceed with the project, did Great Basin conduct an Open Season?**

A. 33 Yes. Great Basin posted a notice of a Non-Binding Open Season on October 5, 2023, notifying interested shippers of a potential expansion of their transmission system downstream of the Wadsworth, Nevada receipt point, namely the 2026 Expansion Project. Interested parties were required to respond by the deadline of October 19, 2023.

**Q. 34 Did Southwest Gas respond to Great Basin's posting of a Non-Binding Open Season for its 2026 Expansion Project?**

A. 34 Yes, the Company submitted a Non-Binding response of 8,129 Dth/day (gross).

**Q. 35 After the conclusion of the Non-Binding Open Season, did Great Basin conduct a Binding Open Season for its 2026 Expansion Project?**

A. 35 Yes, Great Basin posted notice of a Binding Open Season on December 5, 2023. Interested parties were required to respond by December 29, 2023. The deadline was extended on December 26, 2023, and interested parties were required to respond by the new deadline of January 11, 2024.

**Q. 36 Did Southwest Gas respond to Great Basin's posting of a Binding Open Season?**

A. 36 Yes, the Company submitted a Binding response of 8,129 Dth/day (gross).

**Q. 37 At the conclusion of the Binding Open Season for the 2026 Expansion Project, did Great Basin notify the Company of an award of capacity?**

A. 37 Yes, on March 11, 2024, Great Basin notified the Company that its response was accepted.

**Q. 38 After the Company was awarded capacity in the 2026 Expansion Project, did Great Basin require the Company to execute binding PAs?**

A. 38 Yes. The Company executed separate binding PAs for its Northern Nevada and Northern California jurisdictions, respectively.

**Q. 39 Was the Company's decision to enter into an agreement for incremental firm transportation capacity with Great Basin reasonable and prudent?**

A. 39 Yes. The Company's decision to participate in Great Basin's 2026 Expansion Project and enter into a PA for incremental firm transportation capacity for its Northern Nevada service area was reasonable and prudent based on the Company's projected extreme weather design day forecast at the time the decision was made. As detailed above, the Company would not have excess Northern California firm interstate resources available, and there was no unsubscribed capacity available on Great Basin's system. The only options to address the Company's forecasted shortfalls were either through a pipeline expansion or to operate with a resource shortfall. The Company determined that operating with a resource shortfalls was imprudent. Further, as mentioned above and discussed more fully in the prepared direct testimony of Ms. Ayala, the Company's consistent and long-standing forecasting methodology which has been consistently accepted by the Commission, informed and supported the decision to secure incremental capacity to ensure reliable service to customers. Therefore, the Company made the decision to contract with Great Basin for additional incremental firm capacity.

**Q. 40 Does the Company believe that the TSA, when executed with Great Basin, which would result from its participation in Great Basin's 2026 Expansion Project for incremental firm transportation capacity, meets the definition of "Significant operational or capital requirements" as defined in the draft regulations provided to the Legislative Counsel Bureau (LCB) on November 25, 2024 in Docket No. 23-07024 (Draft Regulations)?**

A. 40 Yes. The Company believes that the TSA which would result from its participation in Great Basin's 2026 Expansion Project for incremental firm transportation capacity meets the definition of "Significant operational or capital requirements" as defined in the Draft Regulations for the following reasons[5]. The TSA resulting from the 2026 Expansion Project would be an agreement that 1) will have a term length of 3 or more years and, 2) results solely from the Company's request for

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[5] The Draft Regulations provides the following definition:

***NAC 704.XXXX "Significant operational or capital requirements" defined. (NRS 703.025, 704.210, 704.991)***
*"Significant operational or capital requirements" means:*
*1. The construction of a new transmission, distribution, compression or storage facility or the rehabilitation, replacement, modification, upgrade, uprate or update of existing facilities, or any planned series of such activities addressing the same need, in which the anticipated cost exceeds $5 million; or*
*2. The construction of a single extension facility with 2,000 or more new customers or with a forecasted maximum annual load over the next five years, commencing with the first year following the year when the resource plan or amendment is filed, that is greater than two percent of the gas utility's forecasted load during the first year*
*following the year when the resource plan or amendment is filed; or*
*3. Any long-term arrangement that results solely from a gas utility's request for incremental upstream resources from an interstate pipeline that requires the interstate pipeline to obtain approval from the Federal Energy Regulatory Commission to construct incremental facilities to meet the gas utility's projected demand; or*
4. *Investment in infrastructure that facilitates the introduction of nongeologic gas, including biogas, renewable natural gas, or hydrogen gas into the gas utility's system. "Biogas" has the meaning ascribed to it by NRS 704.99*

incremental upstream resources from Great Basin and requires Great Basin to obtain approval from the FERC to construct incremental facilities to meet Southwest Gas' request.[6]

**Q. 41 Is the Company requesting pre-approval of the TSA resulting from the 2026 Expansion Project in this application?**

A. 41 No. The Company's decision to participate in Great Basin's 2026 Expansion Project and enter into a binding PA committing to the project in order to receive incremental firm transportation capacity took place prior to the development and adoption of the Draft Regulations.[7] However, the Company is including aspects of the firm transportation service it expects to receive from the 2026 Expansion Project in the instant application for informational purposes to comply with the Draft Regulations.

## IV. SOUTHERN NEVADA 2025 LONG-TERM RESOURCE ACQUISITION PROCESS

**Q. 42 Did the Company make a determination that it would have a resource shortfall in its Southern Nevada service area?**

A. 42 Yes. Due to long-term firm upstream transportation and firm bundled delivered supply resources terminating, the Company determined that it would have a resource shortfall in its Southern Nevada service area beginning in the 2026-2027

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[6] The Draft Regulations provides the following definition for "Long-term arrangement:"

> ***NAC 704.XXXX "Long-term arrangement" defined. (NRS XXX.XXX) "Long-term arrangement" means an agreement with a duration of 3 or more years and includes, without limitation;***
> *1. Supply contracts;*
> *2. Agreements for hedging the price of gas;*
> *3. Agreements that involve production wells or inground reserves owned by the utility which are intended to be used as a source of supply;*
> *4. Incremental transportation agreements;*
> *5. Storage agreements; and*
> *6. Any other long-term arrangement that the utility determines should be considered.*

[7] The Company participated in Great Basin's 2026 Expansion Project Binding Open Season in December 2023 (See Q&A 37, above), prior to the requirement for Southwest Gas and Sierra Pacific Company in Docket No. 23-07024 to file initial proposed draft regulations implementing the requirements of Senate Bill 281 (See the Commission's Procedural Order in Docket No. 23-07024 dated September 19, 2023 that required both companies to file initial proposed draft regulations by January 10, 2024.)

gas year.

**Q. 43 For what time period is the Company attempting to secure resources to meet projected shortfalls?**

A. 43 The Company is endeavoring to secure resources for a five-gas year window starting November 1, 2026 through October 31, 2031.

**Q. 44 What steps has the Company taken to resolve this resource shortfall?**

A. 44 To resolve the Southern Nevada resource shortfall, in March 2025 the Company solicited offers for firm upstream transportation capacity and firm bundled delivered supply deals. In April 2025, the Company received several offers for bundled delivered supply deals from various suppliers as well as offers for firm upstream transportation capacity from Kern, Transwestern and El Paso.

**Q. 45 How is the Company going about determining which offers to select?**

A. 45 The Company began the selection process by modeling the offers in its gas resource optimization software, Plexos®.

**Q. 46 How does gas resource optimization modeling work?**

A. 46 Gas resource optimization modeling translates real-world gas system flows into mathematical calculations and leverages powerful algorithms to find the most efficient and cost-effective solution for resource utilization. Essentially, the model solves an objective function, which in this case is utilizing resources in the most efficient and cost-effective way to meet Sales Customers' demands. The model then incorporates decision variables, such as resource availability, costs, system constraints, and monthly variability in demand in its optimization algorithm to obtain the most optimal resource mix.

**Q. 47 Is the utilization of the Plexos® model the only method by which the Company determines the best cost resource mix?**

A. 47 No. While the initial model run sets the stage for an optimized resource utilization, there are situational factors specific to the Company that Plexos® cannot incorporate into its algorithm. Therefore, human experience and expertise is typically required to make refinements to model inputs to produce the resource utilization models for the Company's service territories.

**Q. 48 Were there any specific situational factors that the Company had to consider in this RFP process in Southern Nevada?**

A. 48 Yes. From a modeling perspective, Plexos® chose to optimize firm upstream transportation capacity from Transwestern and El Paso rather than from Kern. However, because 1) both Transwestern and El Paso deliver gas to the same location, SGTC, at different pressures, and 2) the gas must travel a long distance to reach the demand center, the Company cannot expect to reliably flow gas from both pipelines simultaneously. The model generated from Plexos® did not take these constraints into account. Therefore, if the Company had simply contracted resources based on the Plexos® model selections, there would be a probability that some of those contracted resources would not be able to flow during an extreme design day weather event because of the constraints.

**Q. 49 Were there any other situational factors that the Company had to consider?**

A. 49 Yes, as previously mentioned, when the Company receives gas from SGTC, delivered either from upstream interstate pipelines, or from bundled delivered supply sources, the gas must travel a long distance to reach the demand center. The Company's STS is a roughly 80-mile pipeline that receives gas from SGTC at the Arizona/Nevada border and delivers gas to the City of Las Vegas and surrounding areas, where the largest demand center on the system resides.[8] As discussed in the prepared direct testimony of Company witness Thomas W. Cardin, the STS consists of two pipelines that were initially installed in 1956 and 1968 with multiple pipeline sizes and operating pressures. The distance from the

[8] See the prepared direct testimony of Company witness Thomas W. Cardin for specific information pertaining to the STS and any future STS capital work.

receipt point to the demand center (Las Vegas valley) together with the complexities of the STS impacts the amount of gas that the Company is able to flow from the receipt point with SGTC into Southwest Gas' Las Vegas valley system. On the other hand, gas received from city gate taps connected to Kern's system flows directly into the Las Vegas valley demand center and does not have to travel a great distance for customer end use. Therefore, consideration must be given to these complexities in the determination of the maximum volumes that can flow on the STS in any given month.

**Q. 50 At the time of the instant filing, has the Company completed the long-term resource acquisition process for its Southern Nevada service area?**

A. 50 No. The Company is currently working with the interstate pipeline service providers to secure firm capacity. Until the TSAs for that firm capacity are in place, the Company cannot move forward to secure the remaining resources needed to meet demands in the form of bundled delivered supplies, because the supply mix may change if the Company is unable to secure the interstate pipeline capacity.

**Q. 51 Does this conclude your prepared direct testimony in this matter?**

A. 51 Yes.

**SUMMARY OF QUALIFICATIONS**
**LAURA SPURLOCK**

I hold a Bachelor of Arts degree in Economics from Central Michigan University and a Master of Arts in Economics from New Mexico State University. I also hold a Project Management Professional certification from the Project Management Institute.

In November 2002, I joined Southwest Gas as an Analyst in the Revenue Requirements department. In this role, I assisted in cost of service analyses and the preparation of documents and schedules necessary for general rate case filings in each of the Company's state rate jurisdictions, as well as before the Federal Energy Regulatory Commission (FERC). In January 2005, I was promoted to the position of Economist in the Demand Planning group. In this role, I was responsible for performing bill frequency analysis and the development of weather normalized billing determinants for general rate case filings. I was also responsible for the development of short- and long-range demand forecasts used in general rate case filings and by other groups in the Systems Planning department. In August 2009, I was promoted to the position of Supervisor in the Central Gas Dispatch group. In this position, my main responsibility was to oversee the daily nominations and scheduling of sales customers' gas supplies on upstream interstate pipelines until February 2012, when I resumed my role as Economist in Demand Planning.

In November 2014, I was promoted to the position of Manager of the Federal Regulatory Affairs group. My primary responsibilities were to develop and make recommendations to management on strategy, regulatory policy, philosophy, and objectives for FERC related matters, was well as providing cost of service subject matter expertise in interstate pipeline rate proceedings filed with FERC. In July 2018, I was promoted to the position of Manager of the Gas Resources Planning group. In this role, I was responsible for FERC related matters, as well as overseeing the on-going planning of company-wide gas supply, interstate transportation, and storage resource needs. In July of 2023, the name of my team changed to Resource Planning &

Analysis and my title and duties remained the same. In March 2024, the FERC related matters were separated from Resource Planning & Analysis. In my current role, I continue to be responsible for overseeing the on-going planning of company-wide gas supply, interstate transportation, and storage resource needs.

**AFFIRMATION OF LAURA SPURLOCK**

Pursuant to NAC 703.710, Laura Spurlock affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 15th day of September, 2025

Laura L. Spurlock

LAURA SPURLOCK

Exhibit 9

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 25-09___

PREPARED DIRECT TESTIMONY

OF

VALERIA S. ANNIBALI

ON BEHALF OF

SOUTHWEST GAS CORPORATION

September 17, 2025

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of

Valeria S. Annibali

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Valeria S. Annibali

## I. INTRODUCTION

**Q. 1 Please state your name and business address.**

A. 1 My name is Valeria S. Annibali. My business address is 8360 S Durango Dr. Las Vegas, NV 89113.

**Q. 2 By whom and in what capacity are you employed?**

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Gas Supply department. My title is Manager/Sustainable Gas Supply.

**Q. 3 Please summarize your educational background and relevant business experience.**

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

**Q. 4 Have you previously testified before any regulatory commission?**

A. 4 Yes. I have previously provided written and oral testimony before the Public Utilities Commission of Nevada (PUCN or Commission). I have also provided written testimony before the California Public Utilities Commission.

**Q. 5 What is the purpose of your prepared direct testimony in this proceeding?**

A. 5 My prepared direct testimony supports the Company's existing and proposed activities related to nongeologic gas, including but not limited to Renewable Natural Gas (RNG) and responsibly sourced or transported natural gas[1] during

[1] Pursuant to Nevada Revised Statues (NRS) 704.99058, and consistent with the proposed regulations filed with the Legislative Counsel Bureau in Docket No. 23-07024 on November 25, 2024 (Draft Regulations), "Responsibly sourced or transported natural gas" means geologic natural gas that is produced or transported with methane emission intensity levels that are below a certain threshold, as

the 2026-2028 action plan period.[2] My prepared direct testimony also sponsor's the Company's Demand Side Management (DSM) Plan.

**Q. 6 Please summarize your prepared direct testimony.**

A. 6 My direct testimony addresses the following:

- An overview of the Company's Commission-approved RNG activities;
- A request to increase flexibility in allowable RNG activities previously authorized by the Commission in Docket No. 21-01015, including:
  - Modification to the required 30-day notification to the Commission about certain RNG activities;
  - Modification to the $14/Dth (2021$, escalated annually at the US Consumer Price Index (CPI)) price cap;
  - Modification to contract term length ending 2029; and
  - Modification to the purchasing authority ending 2029.
- Request to enter into certain nongeologic procurement activities previously not contemplated in Docket No. 21-01015 as expanded by revised statutes implementing Senate Bill (SB) 281, including;
  - Procurement of responsibly sourced carbon capture and storage (CCS)-enabled natural gas up to 5% of normal weather demand for the Company's Southern and Northern Nevada rate jurisdictions.
- Proposed DSM Plan for approval throughout the action plan period.

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verified by an independent third party, and using processes that demonstrate best practices for production and transportation."

[2] The Draft Regulations define "action plan period" as the three-year period immediately following the date on which a resource plan is filed with the Commission.

## II. PROPOSED MODIFICATIONS TO RNG ACTIVITIES

**Q. 7 Please describe the RNG activities Southwest Gas is authorized to engage in pursuant to Docket No. 21-01015?**

A. 7 Southwest Gas received approval of its Amended Application (RNG Application) for authority to purchase renewable natural gas. The Commission granted approval of RNG activity related to purchasing RNG to be included in its supply portfolio, as modified by the Commission.[3] In its October 27, 2021 order, the Commission authorized Southwest Gas to procure, without prior authorization for each transaction, RNG sufficient to meet up to 1.99% of forecasted demand for inclusion in its supply portfolio via contracts running through the December 31, 2029.[4] The procured RNG must generate demonstrable environmental benefits for Nevada, including D3 and D5-eligible production. Said RNG is also subject to a cost cap of $14/Dth (2021$, escalated annually at the US CPI), inclusive of both the physical RNG methane molecules and any assorted environmental attributes, escalated annually at the US CPI.[5] To the extent that Southwest Gas is requesting the physical incorporation of RNG into its supply, the Company must file with the Commission notice of RNG injections into its distribution system at least 30 days before blending of RNG with conventional natural gas commences.[6] Commission approval and corresponding purchase authority granted in sunsets on December 31, 2029.[7]

**Q. 8 Has Southwest Gas engaged in any other RNG activities?**

A. 8 Yes. Southwest Gas received Commission approval to enter into agreement for the purchase of RNG to meet the requirements of the Regional Transportation

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[3] Docket No. 21-01015.
[4] *Id.* at page 20.
[5] *Id.* at page 22.
[6] *Id.* at page 27.
[7] *Id.* at page 22.

Commission (RTC).[8] Southwest Gas also entered into a contract, at no cost, that allowed for RNG purchases commencing in 2023-2024, which it reassigned to a third-party crediting $12.5 million back to Southwest Gas' Northern and Southern Nevada customers.[9] In a RNG second contract (Contract RNG 2), the Company entered into a sale and purchase agreement to receive continuous payments for a 12-year term of the original agreement. The Company also began receiving payments associated with Contract RNG 2 in August 2024, totaling approximately $3.9 million through July 2025. These payments have been credited to Federal Energy Regulatory Commission (FERC) 191, with approximately $700 thousand credited to Northern Nevada customers and approximately $3.2 million to Southern Nevada customers.[10] Southwest Gas did not proceed with RNG purchases from either RNG contract due to changes in market conditions at the time which increased the risk that the final cost of RNG delivered to Nevada could exceed $14/Dth during periods of high prices in the western US compared to those in the eastern US.

**Q. 9 What modification is Southwest Gas proposing related to RNG activity currently authorized by the Commission in Docket No. 21-01015?**

A. 9 Southwest Gas proposes to modify the requirement to notify its General Service customers in the impacted service territory and file with the Commission notice of RNG injections into its distribution system at least 30 days before blending of RNG with conventional natural gas commences.[11] Southwest Gas also seeks to modify the price cap of $14/Dth (2021$, escalated annually at the US CPI) and remove the December 31, 2029 contract end date restriction and corresponding purchase

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[8] See the Commission-approved Stipulation in Docket No. 22-08007.

[9] In October 2023, $9.875 million and $2.625 million was credited to the Southern and Northern Nevada FERC 191 Accounts, respectively.

[10] The Company filed a courtesy notice with the Commission in Docket No. 21-01015 on January 26, 2024 providing details of the referenced RNG activities.

[11] See the Commission's October 27, 2021 Order in Docket No. 21-01015 at Directive 2 (page 27).

authority sunsetting on December 31, 2029.

**Q. 10 Why is Southwest Gas requesting to modify the 30-day notification requirement prior to RNG blending?**

A. 10 Procurement opportunities require timely decision-making in negotiations and commitments reflective of practices the Company utilizes for other natural gas procurement activities. Southwest Gas has been approached by several suppliers with purchasing opportunities for natural gas produced from RNG facilities that the Company believes is contemplated under RNG activities approved pursuant to Docket No. 21-01015 but the current restrictions have limited the Company's ability to enter into certain transactions. As an example, Southwest Gas has been approached with an opportunity to purchase natural gas sourced at an RNG facility with separated environmental attributes ("brown gas" only) at market-based rates competitive with traditional spot natural gas supplies that could meet the needs of Nevada sales customers. While such a purchase would be defined as an RNG activity as contemplated in Docket No. 21-01015[12], the purchase of the natural gas associated with such RNG production would not meet the definition of RNG to meet the Company's RNG targets as set forth in NRS 704.9991-704.9997 as part of its supply portfolio due to the separated environmental attributes. The purchase would constitute a competitive natural gas spot purchase. However, because the Commission requires a 30-day notice prior to introducing such gas into the Company's distribution system, which includes gas with or without environmental attributes when the purchase is from an RNG facility, Southwest Gas was not able to enter into a purchase agreement for the separated gas supplies for delivery to its Nevada customers. To enable Southwest Gas to enter into procurement agreements for gas separated from

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[12] NRS 704.9997(2)(d) contemplates purchasing gas produced from a renewable natural gas facility whether or not the natural gas includes environmental attributes.

environmental attributes from RNG facilities under the same competitive environment as other traditional gas supplies, Southwest Gas requests the modification to the 30-day notification requirement prior to the purchase of such supplies.

**Q. 11 What modification does Southwest Gas request to the 30-day notification requirement?**

A. 11 Southwest Gas requests a modification to the 30-day notification requirement for the purchase of gas separated of environment attributes from an RNG facility. Southwest Gas requests the Commission treat the purchase of gas separated of environment attributes from an RNG facility as any other spot natural gas purchases and review its prudency through consideration of the Company's the Annual Rate Adjustment (ARA) application. If the modification is granted, Southwest Gas would exclude purchases of gas separated of environmental attributes from RNG facilities from the 30-day noticing requirement set forth in the Commission's Order in Docket No. 21-01015 and, instead, include them in its ARA application for Commission review and approval. The Company proposes to retain the 30-day notification requirement for RNG purchases that retain environmental attributes and will be blended into the Company's distribution system.

**Q. 12 Is the Company seeking approval to modify other previously approved RNG activities as established in the Commission's Order in Docket No. 21-01015?**

A. 12 Yes. Southwest Gas requests a modification to the $14/Dth (2021$, escalated annually at US CPI) price cap as approved in Docket No. 21-01015[13]. Southwest Gas requests the modification to the price limit to align with the dynamic nature of the evolving RNG procurement market. Southwest Gas has observed a growth and a shift in the RNG market since the Commission issued its Order in Docket

[13] *Id.* at pages 27-28.

No. 21-01015 allowing for the Company to purchase RNG for inclusion in its supply portfolio to meet aspirational targets established in NRS 704.9997. The currently established price cap does not allow Southwest Gas the ability to procure RNG supplies to meet the RNG targets established by NRS 704.9997(4).

**Q. 13 What modification to the $14/Dth (2021$) price cap does Southwest Gas propose?**

A. 13 Southwest Gas requests the Commission revise the price cap from the currently established cap of $14/Dth (2021$) to $25/Dth (2025$) with the cap adjusted annually using the CPI. The Company's request to adjust the currently authorized price cap balances changing market dynamics enabling the Company to access competitive RNG supplies to endeavor to achieve legislative goals established in NRS 704.9991 through 704.9997 while considering Nevada residential customer bill impacts.

**Q. 14 What market evidence supports Southwest Gas' request for the $14/Dth (2021$) price cap modification?**

A. 14 Since the approval of the $14/Dth (2021$) price cap in Docket No. 21-01015, Southwest Gas has conducted both formal and informal outreach related to procuring RNG supplies to meet RNG targets established by NRS 704.9997(4). Southwest Gas conducted a Request for Information (RFI) in July 2025 surveying availability and price of RNG supplies for delivery into Nevada. Results of the RFI indicate that the potential for RNG supplies in close proximity to Nevada has improved since 2021 as new projects have come online, however the indicative prices provided in the RFI responses suggest that the currently authorized $14/Dth (2021$) price cap as established in Docket No. 21-01015 does not reflect current competitive market pricing for RNG. Southwest Gas provides a summary of RFI results in Confidential Exhibit Nos.__(VSA-1) and (VSA-2) as well as the escalated price cap demonstrating current pricing conditions reflective of the CPI in Exhibit No. __(VSA-3). Based on responses received from the RFI, RNG prices over a 5-year period from 2026-2031 are expected to vary depending on feedstock ranging from a low of $9.16/Dth for a D5 supply to $43.33/Dth for dairy feedstock with an indicative average price of $21.85/Dth for D3 qualifying feedstock which can be sourced from landfills, agricultural waste, or diverted organic waste.

**Q. 15 What additional analysis did Southwest Gas conduct to assess the impact of its proposed price cap modification?**

A. 15 Southwest Gas conducted an assessment of the proposed $25/Dth price cap on an average Northern and Southern Nevada annual single-family residential customer monthly bills. Southwest Gas assessed that incorporating the currently approved targets of RNG into its supply portfolio for the 2025-2030 period, increased from 1.99% during 2025-2029 up to 2.99% in 2030. Using currently effective rates, Southwest Gas reviewed the impact of incorporating RNG targets established by NRS 704.9997(4) at the proposed price cap during the 2026-2028 action plan period. A customer bill impact analysis evaluating cost impact of non-geologic supplies at a portfolio level provides the flexibility for Southwest Gas to source RNG at competitive market prices while ensuring the prudency of purchased RNG and other non-geologic supplies using customer bill impact analysis to ensure undue burden on its ratepayers while providing emissions reduction benefits. Please refer to the prepared direct testimony of Company witness Christopher M. Brown for additional information regarding estimated customer bill impacts.

**Q. 16 What modifications to the contract term length is Southwest Gas proposing?**

A. 16 Southwest Gas is seeking to modify the current limit on RNG procurement contracts term length which does not allow contract that extend no than December

31, 2029.[14] Southwest Gas requests to modify the requirement for contract term length to such that the term of the contract may not exceed 5 years from commencement of deliveries of non-geologic supplies. For contract term lengths longer than 5 years or beyond 2040, Southwest Gas must seek Commission approval. As such, Southwest Gas also seeks approval to extend its purchasing authority for RNG and other nongeologic supplies beyond the currently approved December 31, 2029 date.

**Q. 17 How will Southwest Gas demonstrate an estimate of the reductions in greenhouse gas emissions (GHG) attributable to RNG activities?**

A. 17 Southwest Gas proposes that the RNG procurement agreements include an annual attestation requirement for carbon intensity (CI) scores for the procured supplies using an industry standard calculation methodology such as the GREET® life cycle analysis.[15] Southwest Gas proposes annual reporting of GHG reductions associated with RNG activities to continue to be provided as part of the ARA application when the associated costs are reviewed prudency.

## III. PROPOSED NONGEOLOGIC GAS ACTIVITIES

**Q. 18 What additional activities is Southwest Gas seeking to include as part of its Resource Plan?**

A. 18 Southwest Gas is seeking approval to purchase responsibly sourced or transported natural gas pursuant to permitted activities under Senate Bill 281 of incorporating commercially-available nongeologic gas supplies. Specifically, Southwest Gas requests approval to incorporate responsibly sourced natural gas (RSG) in the form of CCS-enabled natural gas into its gas supply portfolio to meet

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[14] *Id.* at page 28.

[15] The U.S. Department of Energy (DOE) developed the GREET® (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) life cycle analysis to assess the environmental impacts associated with technologies, fuels, products, and energy systems across various stages of the supply chain. https://www.energy.gov/eere/greet

up to 5% of its normal weather demand in Southern and Northern Nevada.

**Q. 19 Please provide an overview of CCS-enabled natural gas.**

A. 19 CCS-enabled natural gas is a natural gas environmental attribute product that quantifies the CI reduction for natural gas at midstream natural gas processing facilities equipped with CCS.

Based on supplier feedback, it is Southwest Gas' understanding that traditionally, carbon dioxide ($CO_2$) concentrations in untreated natural gas varies between 2% - 8%, but can be as high as 20% in some areas of the US. This requires the natural gas to be sent to a gas processing plant to remove liquids and other impurities, including $CO_2$, as high concentrations of these impurities can cause corrosion over time and reduce the overall energy content. As is common practice, the $CO_2$ removed from the natural gas stream is typically vented directly into the atmosphere accounting for as much as 20 lbs of $CO_2$ vented per MMBtu of natural gas processed.

The processing of raw natural gas to pipeline grade specifications, specifically $CO_2$ removal via amine gas treatment is a contributor of $CO_2$ emissions in the upstream or wellhead to city gate natural gas supply value chain. With CCS-enabled natural gas, the gas processor captures, compresses and transports the $CO_2$ via pipeline and injects it for permanent sequestration. CCS investment results in a net reduction in gas processing emissions at the processing plant which results in a net CI reduction for the natural gas processed at the facility as provided in Exhibit No.__(VSA-4).

**Q. 20 Is CCS-natural gas verifiable and certified by a reputable crediting agency?**

A. 20 Yes. For each tonne of $CO_2$ sequestered by the processing facility, a verified carbon credit is generated in a reputable carbon credit registry such as the American Carbon Registry (ACR) or Climate Action Reserve (CAR). For each MMBtu of natural gas processed by the processing facility, a corresponding

Environmental Attribute Certificate (EAC) is generated using a recognized renewable/alternative gas certification standard such as MiQ.[16] As provided in Exhibit No.__(VSA-5), Southwest Gas would purchase CCS-enabled natural gas accompanied by the carbon credits generated using a CCS Protocol. These carbon credits will then be permanently retired on the ACR or CAR registry on behalf of Southwest Gas customers, such that a supplier-specific emission rate reduction will be reflected on the EAC, thereby linking a certified metric ton of $CO_2$ sequestered at the facility to a MMBtu of natural gas processed at the facility. For the avoidance of doubt, the carbon credit will not be sold to a third-party in any scenario and only retired on behalf of Southwest Gas' Southern or Northern Nevada customers. The EAC is also permanently retired by Southwest Gas on behalf of its customers. This process ensures: (a) that there is no double-counting associated with the carbon credit and/or EAC by an unaffiliated third party, and (b) only the EAC buyer (i.e. Southwest Gas) and its customers (i.e. natural gas end-users) can claim the supplier-specific emissions reduction.

This approach serves the following two purposes: (1) obtaining a third-party certified annual throughput, and (2) obtaining third-party certified emissions reductions. Given the restrictions around project boundaries for each certifying entity, utilizing only one certifier under one standard wouldn't achieve the same result of an in-value chain carbon reduction (i.e. an inset) supported by a supplier-specific emissions factor tradeable on a per MMBtu basis. While both carbon offsets and insets aim to reduce GHG emissions, they differ significantly in their approach, impact, and value.

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[16] The MiQ Standard is a standalone framework to assess the methane emissions intensity and carbon (CO2e) intensity at the asset level from each stage of the natural gas supply chain and some stages of the crude oil and natural gas liquids supply chain. The MiQ Standard is followed by MiQ operators and used by accredited, independent auditors to assess an operator's emissions intensity and overall emissions performance. https://miq.org/the-technical-standard/

Offsetting compensates for emissions by investing in projects that reduce or remove an equivalent amount of $CO_2$ or other GHG emissions from the atmosphere while insetting focuses on reducing emissions directly within a company's own value chain or supply chain. For companies with significant value chain emissions (e.g., food & beverage, manufacturing, data centers), insetting offers a more integrated and impactful approach, leading to long-term sustainability and resilience.

A reduced CI MMBtu of natural gas can be used to reduce both, Southwest Gas' default emissions factor for the calculation of Scope 3, Category 11 Emissions from the sale of natural gas, and a consumer's default emissions factor for the calculation of Scope 3, Category 3 Fuel and Energy Related Activities from natural gas.

**Q. 21 How will Southwest Gas demonstrate an estimate of the reductions in GHGs attributable to CCS-enabled natural gas activities?**

A. 21 Southwest Gas will use the following framework for the emissions reduction calculation:

(1) For the value of "***MTs of CO2 Sequestered***" generated during the creation of carbon credits that accompany the CCS-enabled natural gas process, Southwest Gas will utilize the accredited registry protocols for calculating emissions removal or destruction.

(2) For the value of "***MMBtus of NG Processed***" generated during the treatment of the natural gas at the facility, Southwest Gas will rely on the methodology and attestation from accredited platforms and protocols such as MiQ.

(3) For the value of "***Supplier-Specific Emission Rate Reduction***" which is calculated using the equation below, will reflect the emissions reduction benefit that translates to Southwest customers on a per MMBtu basis and that are certified and reflected on the purchased EAC.

$$Supplier\ Specific\ Emission\ Rate\ Reduction = \frac{MTs\ of\ CO2\ Sequestered}{MMBtus\ of\ NG\ Processed}$$

**Q. 22 Are you able to estimate how purchasing CCS-enabled natural gas will benefit customers and the environment?**

A. 22 Yes. For example, if Southwest Gas purchases CCS-enabled natural gas of up to 5% of 2026 normal weather demand in its Northern and Southern Nevada service territory, its customers can benefit from up to 15,445 tonnes of carbon dioxide equivalent (tCO2e)/year in emissions reductions – equivalent to removing emissions from 3,605 gasoline-powered passenger vehicles driven for one year. Southwest Gas customers can potentially claim up to a decrease of approximately 40% on upstream emissions, on a pro-rata basis. Please refer to Exhibit No.__(VSA-6) an example calculation based on the provided methodology to calculate the emissions rate reduction attributable to CCS-enabled natural gas.

**Q. 23 How is CCS-enabled natural gas different from other RSG currently available in the market?**

A. 23 Responsibly sourced or certified natural gas use frameworks that reflect broad categories of performance on GHG mitigation but do not quantify specific emissions reductions to the accuracy needed to make a high-integrity Scope 3 reduction claim. CCS-enabled gas uses reputable carbon credit protocols to quantify specific $CO_2$ reductions from projects that meet high standards for GHG mitigation. This allows the purchaser and end users of the EAC to use supplier-specific emissions factors in their Scope 3 accounting that attribute the CO2 reductions. CCS-enabled natural gas also meets a higher standard by incentivizing much-less common practices of GHG mitigation that rely on carbon value to create real, measurable, verifiable, emissions reductions in traditionally hard to abate supply chain segments like processing. Currently a limited number of natural gas processing plants are equipped with CCS as it is typically not economically viable to invest in a CCS project at an operating facility without realizing incremental environmental attribute value.

**Q. 24 What are the benefits of CCS-enabled natural gas?**

A. 24 CCS-enabled natural gas provides incremental, real, and certifiable emissions reductions. Southwest Gas believes that CCS-enabled natural gas provides a greater incremental emissions reduction benefit than RSG or certified natural gas alone with incremental costs comparable to that of certified natural gas equating to approximately 25 cents per MMBtu[17]. Further investments in CCS technology at natural gas processing plants will be more economically viable and, as more projects get built, millions of tonnes of CO2 emissions reductions would be realized.

**Q. 25 How will Southwest Gas implement the purchase of CCS-enabled natural gas?**

A. 25 Southwest Gas will seek supplies through a competitive procurement process as it currently uses for its traditional supplies. Southwest Gas will use established processes carbon offset tracking for its Nevada Move2Zero Program to validate the process for CCS-enable natural gas associated carbon credit retirement and to demonstrate customer benefits. Southwest Gas proposes separate tracking for CCS-enabled natural gas purchases, emissions reductions based on the proposed methodology, and for the Commission to review the prudency of CCS-enabled natural gas purchases as part of its ARA application.

[17] Million British thermal units.

**Q. 26 What are the estimated incremental costs associated with CCS-enabled natural gas as compared with geologic supplies?**

A. 26 Based on initial market outreach, Southwest Gas believes that CCS-enabled natural gas averages 15-50 cents per MMBtu above conventional natural gas prices. Southwest Gas proposes to include the related costs for prudency review in its ARA application and to assess the incremental costs from CCS-enabled natural gas as part of an overall nongeologic supply portfolio with the combined customer bill impact from the purchase of aspirational RNG targets and CCS-enabled natural gas in the Resource Plan. As such, Southwest Gas proposes a price cap on CCS-enabled natural gas purchases of $0.50/MMBtu (2025$) above conventional geologic natural gas purchases, escalated annually using the CPI.

**Q. 27 Has cost recovery of incremental costs associated with RSG or certified natural gas been previously authorized by any other utility commission or state?**

A. 27 Yes. The Public Utilities Commissions in both Virgina and Tennessee have authorized public utilities to recover costs associated with RSG through their purchased gas adjustment (PGA) mechanism.[18]

**Q. 28 What analysis did Southwest Gas perform to assess the impact on customer bills related to CCS-enabled natural gas?**

A. 28 Southwest Gas evaluated customer bill impact of purchasing CCS-enabled natural gas at the proposed cap of $0.50/MMBtu (2025$) above conventional geologic natural gas purchases escalated annually using the CPI to meet up to 5% of its normal weather demand in Nevada. That estimated bill impact is discussed in the prepared direct testimony of Christopher M. Brown.

[18] See Code of Virginia §56-604 and Tennessee Code § 65-5-114.

## IV. SUMMARY OF THE PROPOSED DSM PLAN

**Q. 29 Please summarize the Company's proposed DSM Plan for the 2026-2028 action plan period.**

A. 29 The DSM Plan for the 2026-2028 action plan period contemplates the continuance of the three programs (Residential Incentives Program, Commercial Incentives Program, and Energy Education Program) previously approved by the Commission in Docket No. 24-06037 with modifications to offered measures. The proposed DSM Plan also contemplates a low-income focused program called Residential Equipment Direct Install (REDI) Rebates Program, a New Construction Program, and a Custom Program.

The DSM Plan details program descriptions that include objectives, customer eligibility, measure specifications and incentives, estimated participation, outreach, evaluation, measurement, and verification (EM&V) plans, budgets, cost-effectiveness results, estimated energy and water savings, and estimated potential GHG emissions reductions. Each DSM program contains assessment data, such as incremental costs and annual savings, that were used to determine program feasibility and cost effectiveness.

**Q. 30 Please identify the market segments Southwest Gas intends to reach with the programs included in its DSM Plan for the action plan period.**

A. 30 Southwest Gas has designed a suite of programs to target the different sales segments within the Company's Nevada service territories. Southwest Gas is also proposing to extend certain residential measures through its REDI Rebates Program to support Asset Limited, Income Constrained, Employed (ALICE) households[19]. The ALICE population describes a large segment of the population that earns above the Federal Poverty Level (FPL) and would fall outside of certain

[19] United Way: https://www.unitedforalice.org/meet-alice

low-income assistance programs, but not enough to afford basic household necessities.

## V. PROPOSED DSM PROGRAMS

**Q. 31 Please provide an overview of Southwest Gas' proposed programs in the Company's DSM Plan for the 2026-2028 action plan period.**

A. 31 Southwest Gas proposes program structure revisions to the Commercial and Residential programs currently approved.[20] Notably for the Commercial Incentives Program, Southwest Gas proposes the addition of a Commercial Custom Incentive measure and separately evaluates cost savings for the Commercial Foodservice Program. For the Residential Incentives Program, Southwest Gas proposes to expand its program to dedicate a portion of requested DSM Plan funds to serve income-constrained communities through the proposed REDI Rebates Program and reclassifies certain builder targeted measures under the Residential New Construction Program. Below is a summary of each program:

- Commercial Incentives Program: Incentives will be offered to participating customers for qualified program measures upon proof-of-purchase and installation. Southwest Gas requests the approval for the following measures:
  - Continued measures: natural gas storage water heating and two tiers of high-efficiency[21] natural gas furnaces. Expanded measures: two tiers of small boilers; large boiler; infrared heater; and volumetric and hybrid water heaters.
  - Custom Incentives Measure: Southwest Gas also requests the addition of a custom cost-effective incentive measure to be included in the DSM Plan for the 2026-2028 action plan period. Southwest Gas proposes a

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[20] The PUCN previously approved Southwest Gas' Commercial Incentives Program, Residential Incentives Program, and Energy Education Program in Docket No. 24-06037.

[21] For both commercial and residential furnaces, Tier 1 ≥ 90% AFUE. Tier 2 ≥ 95% AFUE.

custom measure for projects that can demonstrate therm savings that are not covered by the Commercial Incentives Program. Baseline and estimated savings must be calculated prior to Pre-Approval. Qualified and licensed Service Provider must install upgrades.

- Commercial Foodservice Program: Incentives will be offered to participating customers for qualified program measures upon proof-of-purchase and installation or through point-of-sale (POS) incentives. Southwest Gas requests the following measures as approved in Docket No. 24-06037:
  - fryers, conveyor, convection and combination ovens

  Southwest Gas requests the following expanded measures:
  - griddles, steam cookers, broilers, open cooktop, rotisserie, commercial and undercounter low temperature dishwashers.
- Residential Incentives Program: Incentives will be offered to participating customers for qualified program replacement measures upon proof-of-purchase and installation of qualified residential program measures. Southwest Gas Residential Incentive Program will offer incentives for tankless water heaters and two tiers of high-efficiency natural gas furnaces in both Northern and Southern Nevada. The Residential Incentives Program will also offer incentives for high efficiency windows in Northern Nevada only.
- Residential New Construction Program: Southwest Gas proposes to reframe certain offered measures to builders under the Residential New Construction Program to provide clarity in incentive processing. Southwest Gas proposes to continue the currently approved in Docket No. 24-06037 natural gas tankless water heater measures for both Northern and Southern Nevada. Southwest Gas requests approval for add the higher-efficiency furnace (95.1%-96.9% AFUE) measure for both Northern and Southern Nevada.
- Residential Equipment Direct Install (REDI) Rebates Program: REDI will

provide support to communities through increased accessibility to more efficient appliances to increase energy savings and reduce customer energy costs by offering a higher tiered incentive structure compared to the Residential Incentives Program on certain residential replacement measures. Southwest Gas requests to offer incentives covering up to 75% of measure cost for the following measures:

- clothes washer (gas water heating), natural gas clothes dryer, dishwasher (gas water heating). Southwest gas will also be offering incremental incentives for storage and tankless water heater, high-efficiency (95.1%-96.9% AFUE) furnaces, and furnace tune-up services.

- Energy Education Program: Southwest Gas proposes to continue its Energy Education Program that educates and assists customers, teachers, and students regarding the efficient use of energy in their homes, apartments, multi-family dwellings, and mobile homes. The Company endeavors to collaborate with local utilities when feasible. Southwest Gas' Energy Education Program comprises the following components:
  - Residential Energy Education
  - Commercial Energy Education
  - Primary and Secondary School Energy Education

  Southwest Gas proposes to continue the use of Home Energy Reports as part of its continued energy education program with a revised outreach approach to include paper reports sent to low-income, income-constrained, and high-usage customers to encourage increased energy conservation efforts. Additionally, Southwest Gas requests the continuation of its energy education kits supporting the Primary and Secondary School Energy education with kit content revisions to focus conservation efforts through improved weatherization content. Southwest Gas is also collaborating with Energy Education implementors to enhance installation tracking and energy savings of installed kits.

**Q. 32 How will Southwest Gas' proposed REDI Program benefit its Nevada customers?**

A. 32 REDI targets residential customers that may not qualify for state funded low-income weatherization assistance programs (150 percent of Federal Poverty Guidelines) and fall below 350 percent of Federal Poverty Guidelines. The REDI Rebates Program will offer a higher tiered incentive as compared to the Company's traditional Residential Incentives Program with incentives covering up to 75% of measure cost, reducing the cost burden of obtaining higher efficiency appliances to qualifying participants. REDI offers the higher tiered rebates for direct installation of water heating and high-efficiency appliances to qualified residential customers in single-family, multifamily, and mobile homes.

**Q. 33 How will Southwest Gas' proposed New Construction Program benefit its Nevada customers?**

A. 33 Southwest Gas has seen significant interest and participation in its previously approved commercial incentives for homebuilders over the last several years and believes that revising the process for the program under the New Construction Program would clarify the offered savings and improve the application process. Additionally, Southwest Gas believes that including additional measures in its proposed New Construction Program focusing on higher building efficiency incentives encourage builders to utilize best building practices in homes which benefits Southwest Gas customers through increased efficiencies. Reduced energy use translates into lower resource consumption and GHG emissions supporting sustainable living. As such, Southwest Gas is reframing offerings to homebuilders through its Residential New Construction Program focused on advancing high-performance energy efficiency in both single-family and multi-family new construction.

**Q. 34 How will Southwest Gas' proposed Custom Incentive measure as part of the Commercial Incentives Program benefit its Nevada customers?**

A. 34 Southwest Gas' Custom Measure sets aside an amount of funding dedicated to furthering emerging energy efficient technologies such as natural gas combined heat and power and hybrid gas/electric air-cooled chillers. Qualifying measures will be reviewed by engineering staff for demonstrated efficiency that is reflective of national efficiency standards and demonstrate benefit to Nevada customers.

**Q. 35 How will Southwest Gas' proposed DSM Plan for the 2026-2028 action plan Period impact statewide GHG emissions?**

A. 35 Southwest Gas' proposed DSM Plan is estimated to achieve approximately 30.5 million lifetime therm savings across Northern and Southern Nevada proposed programs as provided in Exhibit No.__(VSA-7). The United States Environmental Protection Agency's default $CO_2$ emissions factor relating to the combustion of natural gas is 0.0053 metric tons $CO_2$ /therm.[22] Applying this factor to the estimated therms savings, equates to a reduction of approximately 161,000 metric tons of $CO_2$ emissions, equivalent to the energy needed to power 33,500 homes for one year.

## VI. LIFE-CYCLE COST ANALYSIS AND METHODOLOGY

**Q. 36 What tests is Southwest Gas proposing to utilize in determining the cost-effectiveness of conservation and energy efficiency programs?**

A. 36 Southwest Gas utilized three separate cost-effectiveness test calculations for both Northern and Southern Nevada – Total Resource Cost (TRC), Participant Cost Test (PCT), and Utility Cost Test (UCT). A TRC Test is a discounted cash flow

[22] U.S. Environmental Protection Agency; https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

analysis that compares the present value of saved energy and natural resources against the present value of energy efficiency program costs, including Southwest Gas' cost for incentives and administration, plus customers' incremental out-of-pocket costs, i.e., the incremental cost of energy-efficiency measures less incentives.

The present value of the energy and natural resources saved divided by the present value of the program costs is referred to as the cost-effectiveness ratio. If the present value of the energy and natural resources saved is greater than the present value of the program costs, the program is deemed to be cost-effective and can be offered to customers to help customers maximize the implementation of cost-effective energy saving opportunities.

The PCT is built to evaluate the program from the program participant point of view. It evaluates the quantifiable costs and benefits from the perspective of the customer installing the energy efficiency measure. The benefits of the PCT assess the energy bill reduction over the measure lifetime and incentive payments while the costs account for incremental costs of equipment and installation. The PCT focuses on the program participant and provides only a partial view of the program since it does not capture program determinants such as marketing and outreach costs needed to implement the program.

The UCT compares benefits and costs from the utility perspective. The benefits evaluate the avoided supply costs for the utility while the costs include both program costs and incentive payments.

**Q. 37 Please describe the cost-effectiveness calculations Southwest Gas has prepared to support its DSM Plan.**

A. 37 Southwest Gas prepared life-cycle cost analysis of the costs and benefits of each program with the following parameters:

- Three separate cost-effectiveness test calculations for both Northern and Southern Nevada – Total Resource Cost (TRC), Participant Cost Test (PCT), and Utility Cost Test (UCT);
- Use of the respective Northern and Southern Nevada after-tax weighted average cost of capital (WACC) for the discount rate;
- Use of the Northern and Southern Nevada 2024 average avoided gas costs; and
- Use of net-to-gross ratios to discount the energy savings and incremental customer costs attributed to the implementation of the DSM Plan.

Southwest Gas provides program and measure specific calculations in its DSM Plan provided as Appendix D of Southwest Gas' Triennial Resource Plan. Exhibit No.__(VSA-8) provides a portfolio level cost-effectiveness summary for Southwest Gas proposed programs.

**Q. 38 What is Southwest Gas' proposed budget for the DSM Plan?**

A. 38 Southwest Gas proposes an annual budget of approximately $3.3 million for 2026-2028 action plan period. Southwest Gas has also requested that the Company continue to have the flexibility to direct funds between and among the Commission-approved CEE programs and individual measures up to 20 percent as was approved in Docket 21-05001, to meet any changing market and economic conditions that it may face during the action plan period.

**Q. 39 How will Southwest Gas recover the costs for its DSM programs?**

A. 39 Southwest Gas will account for the costs of its DSM Plan in accordance with NAC 704.9714, consistent with how it accounts for similar costs today. As such, all costs attributable to the DSM Plan will be separately accounted for on the Company's books and records. Southwest Gas' accounting and recordkeeping will allow total DSM Plan costs to be segregated from other activities of the utility and allow an accurate determination of costs that can be specifically attributable to each program. Consistent with how it currently files its Conservation and Energy Efficiency rates, Southwest Gas will file DSM program cost rates for its Northern and Southern Nevada rate jurisdictions as part of its ARA Application, which is required to be filed annually November 15, with an effective date of the following July.[23]

**Q. 40 Does this conclude your prepared direct testimony in this matter?**

A. 40 Yes.

[23] As approved in Docket No. 20-05028.

**SUMMARY OF QUALIFICATIONS**
**VALERIA S. ANNIBALI**

I hold a Bachelor of Arts degree in Economics and International Affairs from James Madison University and a Master of Science Degree in Applied Economics from Johns Hopkins University.

I first worked for Southwest Gas Corporation (Southwest Gas or Company) between September 2015 and January 2020. During that period, I held the positions of Senior Analyst in Gas Purchasing and Transportation and Senior Analyst in Regulation and Energy Efficiency. While in Gas Purchasing and Transportation my primary responsibilities included negotiating daily and monthly gas purchase transactions that helped ensure that Southwest Gas purchased gas supplies at the best cost considering market price impacts and ensuring reliability scheduling supplies on interstate natural gas pipelines. As a Senior Analyst in Regulation and Energy Efficiency, I supported in the development of the Company's renewable natural gas and decarbonization initiatives including tariffs, internal and external presentations, and customer communication initiatives. I also assisted in the development of financial and operational analysis in preparation of cost recovery initiatives for federal and state regulatory filings, prepared regulatory filings including testimony drafting, and provided responses to data requests from state and federal commission Staff and other public agencies.

Between January 2020 and December 2021, I relocated to Houston, Texas where I was a Manager at Deloitte & Touche's Regulatory and Operational Risk offering within Risk and Financial Advisory service. During my time with Deloitte, I led client engagements including compliance risk assessments related to federal and state regulatory requirements, solution implementation for business strategies and policies, business process development, organizational structure changes, management reporting, and trading and risk systems effectiveness evaluations. I also provided subject matter expertise on federal and state regulatory matters to advise and develop innovative approaches supporting utility and oil and gas clients with compliance matters including controls testing, reporting, record keeping, and reconciliation.

In December 2021, I returned to work at Southwest Gas where I now hold the position of Manager/Sustainable Gas Supply. I am accountable for the negotiation and administration of the Company's sustainable gas purchase contracts, including but not limited to contracts for renewable natural gas, biogas, hydrogen, carbon offsets, as well as the administration of the Company's California Cap & Trade allowance purchase program, and various regulatory filings to which Gas Supply contributes. My responsibilities include soliciting, negotiating, and contracting for the sustainable gas supply resources and integrating sustainable gas supplies into the Company's supply portfolios. I am also responsible for responding to data requests from the Federal Energy Regulatory Commission (FERC), state commissions, and intervenors that relate to Company's sustainable gas supply practices. I also oversee the Company's Energy Efficiency activities across all three states that we serve: Arizona, Nevada and California and low-income programs in California and Arizona.

Prior to joining Southwest Gas in 2015, I was an Energy Industry Analyst at the FERC's Office of Enforcement between October 2011 and September 2015. I managed national and regional initiatives on gas-electric coordination, led natural gas technical analysis, apprised Commissioners of latest market developments, and produced and presented technical as well as seasonal market assessments at Commission Open Meetings. Prior to FERC, I was a senior analyst at various consultancies responsible for natural gas market fundamentals and price forecasting.

## *Summary of Southwest Gas' RFI Pricing Results by Feedstock Min/Max/Average (5-Year Period)*

[redacted]

[redacted]

## *Summary of Southwest Gas' RFI Pricing Results by Feedstock Annual Price (5-Year Period)*

[redacted]

Note: Manure is not cost competitive with other feedstocks and is excluded for illustrative purposes.

## $14/Dth Price Cap Escalated Using Consumer Price Index (CPI)*

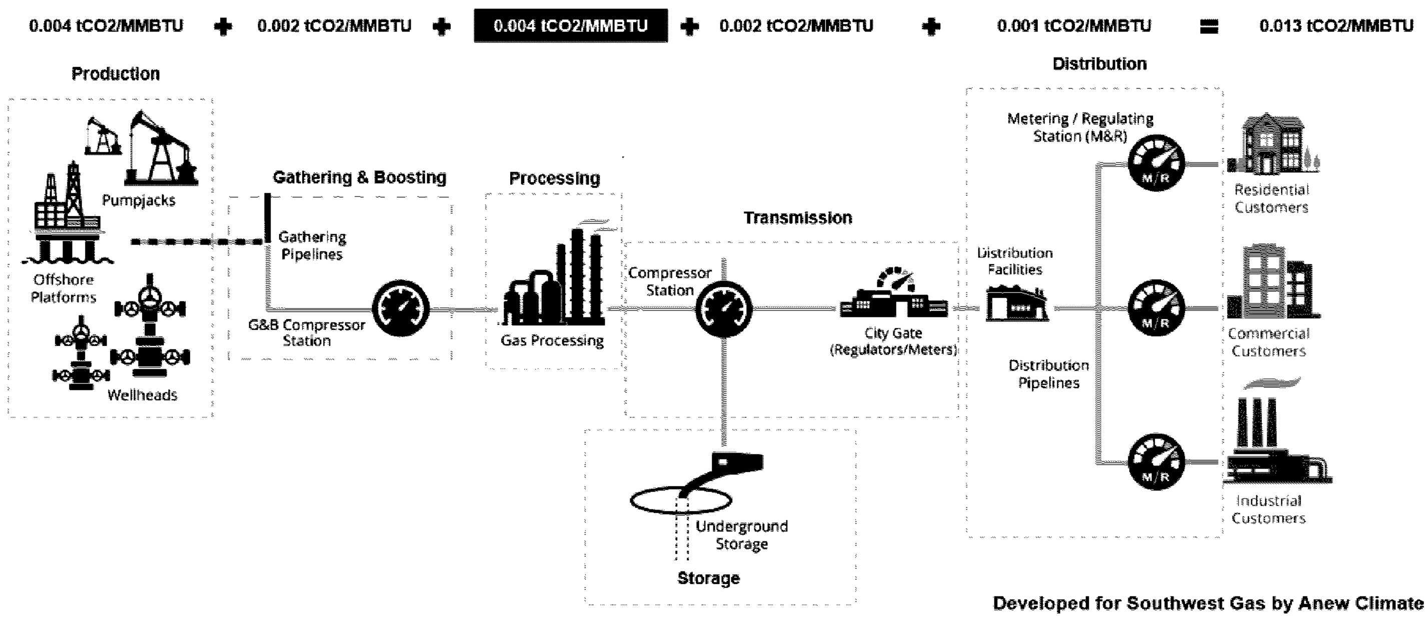
| Year | CPI Escalator | Price |
|---|---|---|
| 2021 | N/A | $14.00 |
| 2022 | 8.00% | $15.12 |
| 2023 | 4.12% | $15.74 |
| 2024 | 2.98% | $16.21 |
| 2025 | 2.30%** | $16.58 |

*https://www.bls.gov/regions/mid-atlantic/data/consumerpriceindexhistorical_us_table.htm

**2025 CPI Escalator is based on available information through July 2025.

***Pre-CCS Upstream Natural Gas Emissions Value Chain***

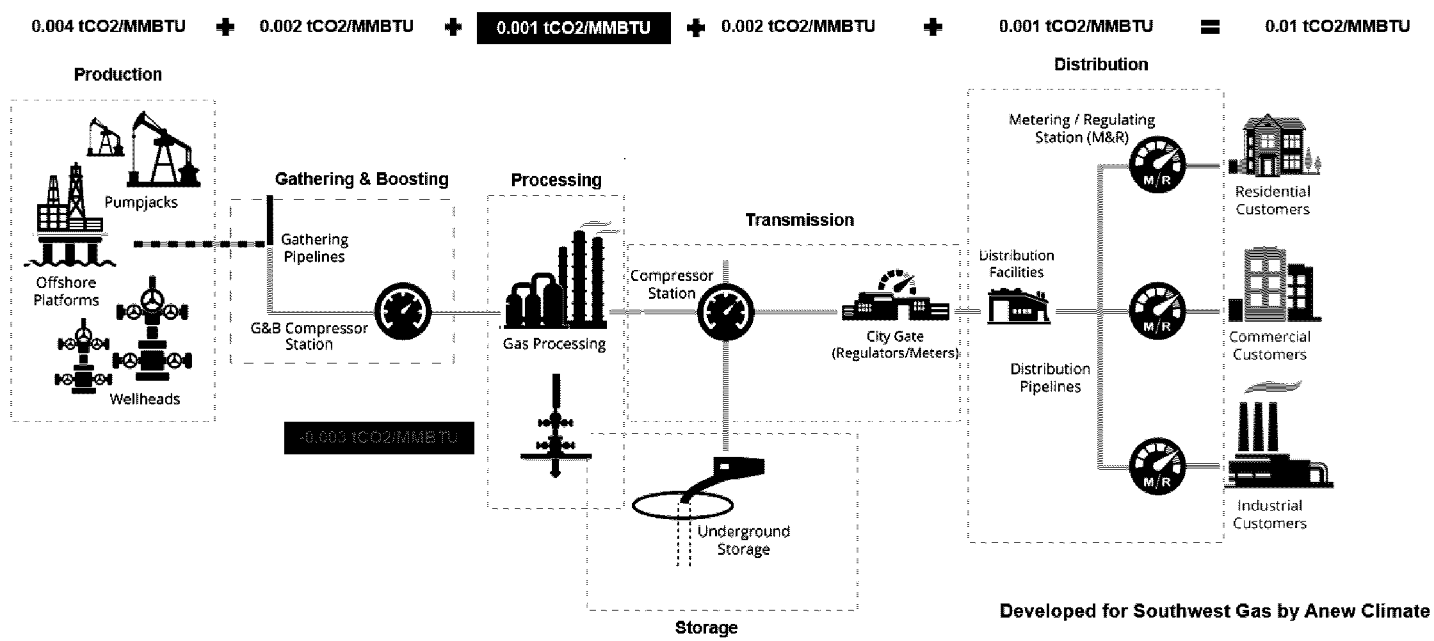
# Upstream Natural Gas Emissions Value Chain




**Developed for Southwest Gas by Anew Climate**

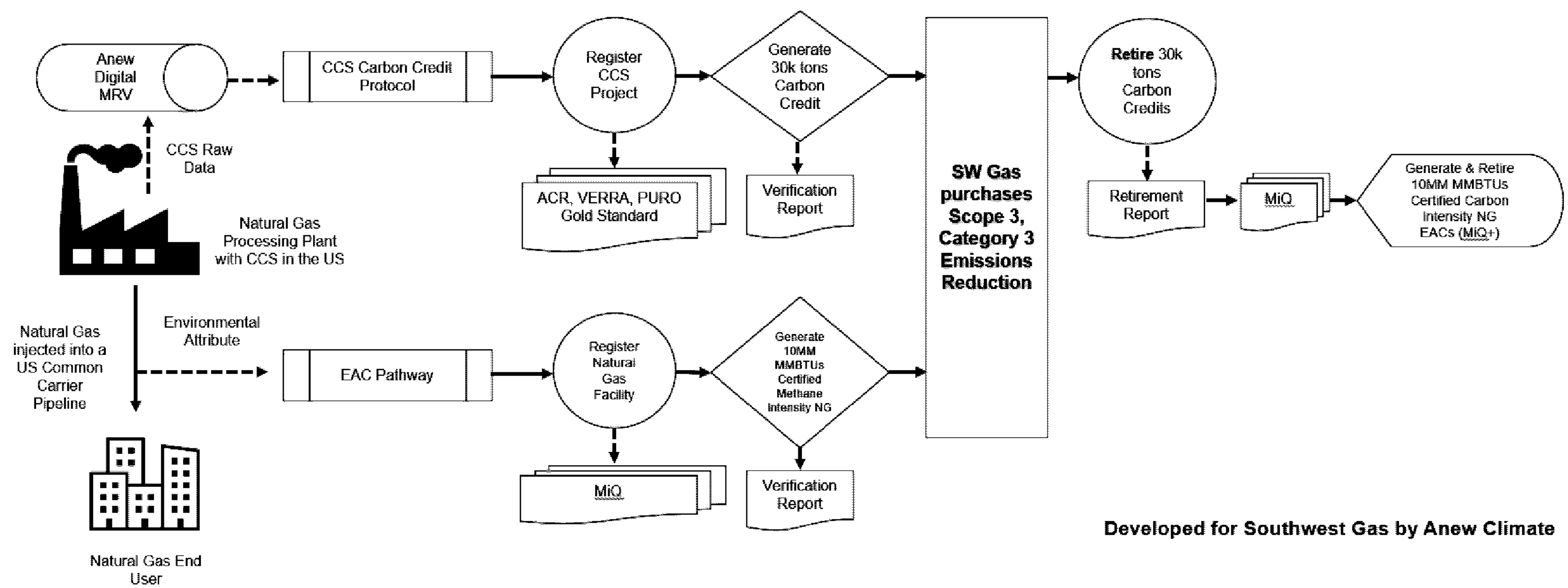
***Post-CCS Upstream Natural Gas Emissions Value Chain***

# Natural Gas Emissions Value Chain



*CCS-enabled natural gas Environmental Attribute Generation & Delivery*

# Case Study – CCS NG EA Generation & Delivery




**Developed for Southwest Gas by Anew Climate**

## Example CCS-Enabled Natural Gas GHG Reduction Calculation

| | Value | Source |
|---|---|---|
| 3rd Party Certified Annual MTs of CO2 Sequestered (MTs): | 105,421 | Facility-Specific, certified annually by ACR or other similar widely recognized carbon registry and protocol |
| 3rd Party Certified Annual MMBtus of NG Processed (MMBtus): | 19,921,655 | Facility-Specific, certified annually by MiQ or other similar widely recognized responsibly sourced gas registry and protocol |
| Supplier-Specific Emissions Factor (MT CO2e/MMTBU): | 0.0053 | Calculated annually based on Facility-Specific, 3rd Party Verified MTs of CO2 Sequestered divided by MMBtus of NG Processed |

| | 2019 | 2025 | End-User | Source |
|---|---|---|---|---|
| EPA NG Emissions Factor (MTs CO2e/MMBtu): | 0.053 | 0.053 | 0.013 | EPA GHG Natural Gas Emissions Factor; ACS; Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways |
| Certified Emission Rate Reduction (MTs CO2e/MMBTU): | 0.005 | 0.005 | 0.005 | Calculated annually based on Facility-Specific, 3rd Party Verified MTs of CO2 Sequestered divided by MMBtus of NG Processed |
| Supplier-Specific Emissions Factor (MT CO2e/MMTBU): | 0.048 | 0.048 | 0.008 | EPA NG Emissions Factor minus Certified Emission Rate Reduction |
| MMBtus Sold: | 57,107,652 | 58,374,311 | 1,000,000 | Nevada State Statistics; Customer Estimate |
| Baseline Emissions (MTs): | 3,033,262 | 3,100,540 | 13,000 | MMBtus Sold multiplied by EPA NG Emissions Factor |
| Post-CCS Enabled Natural Gas Emissions (MTs): | 2,731,060 | 2,791,636 | 7,708 | MMBtus Sold multiplied by Supplier-Specific Emissions Factor |
| Delta (MT): | 302,201 | 308,904 | 5,292 | Baseline Emissions minus Post-CCS Enabled Natural Gas Emissions |
| Offset 5% of Emissions from MMBTUs Sold: | 15,110 | 15,445 | 265 | 5% multiplied Delta |
| % Reduction: | 9.96% | 9.96% | 40.71% | Delta divided by Baseline Emissions |

## Lifetime Net Savings (therms)

| Southern Nevada Program | Year 1 | Year 2 | Year 3 | 3-Yr Total |
|---|---|---|---|---|
| Residential Incentives | 133,523 | 133,523 | 133,523 | 400,569 |
| Residential New Construction | 3,417,185 | 3,417,185 | 3,417,185 | 10,251,556 |
| Home Energy Report Program | 524,350 | 520,575 | 511,627 | 1,556,552 |
| Low-Income Home Energy Report Program | 131,087 | 130,144 | 127,907 | 389,138 |
| REDI | 104,343 | 104,343 | 104,343 | 313,029 |
| Commercial Incentives | 1,495,922 | 1,495,922 | 1,495,922 | 4,487,765 |
| Commercial Foodservice | 808,029 | 808,029 | 808,029 | 2,424,086 |
| Commercial Energy Education Program | 400,689 | 400,689 | 400,689 | 1,202,067 |
| School Education Program | 684,000 | 684,000 | 684,000 | 2,052,000 |
| **Total Savings (therms)** | **7,699,128** | **7,694,410** | **7,683,225** | **23,076,763** |

| Northern Nevada Program | Year 1 | Year 2 | Year 3 | 3-Yr Total |
|---|---|---|---|---|
| Residential Incentives | 50,689 | 50,689 | 50,689 | 152,067 |
| Residential New Construction | 1,328,227 | 1,328,227 | 1,328,227 | 3,984,680 |
| Home Energy Report Program | 75,730 | 75,185 | 73,893 | 224,808 |
| Low-Income Home Energy Report Program | 18,933 | 18,796 | 18,473 | 56,202 |
| REDI | 12,851 | 12,851 | 12,851 | 38,552 |
| Commercial Incentives | 555,598 | 555,598 | 555,598 | 1,666,794 |
| Commercial Foodservice | 300,729 | 300,729 | 300,729 | 902,186 |
| Commercial Energy Education Program | 50,640 | 50,640 | 50,640 | 151,920 |
| School Education Program | 68,400 | 68,400 | 68,400 | 205,200 |
| **Total Savings (therms)** | **2,461,796** | **2,461,114** | **2,459,499** | **7,382,409** |

## Savings and Cost-Effectiveness Summary

| Southern Nevada - PROGRAM PORTFOLIO (3 Years) | | | | | | |
|---|---|---|---|---|---|---|
| | Total Resource Cost | | Participant Cost Test | | Utility Cost Test | |
| **PROGRAMS** | NPV | B/C | NPV | B/C | NPV | B/C |
| Residential Incentives | $83,890 | 1.7 | $240,270 | 2.8 | $109,030 | 2.1 |
| Residential New Construction | $2,076,143 | 1.6 | $5,683,257 | 2.5 | $2,967,397 | 2.2 |
| REDI | -$417,772 | 0.3 | $353,589 | 2.4 | -$697,651 | 0.1 |
| Commercial Incentives | $1,322,836 | 2.1 | $2,339,791 | 3.0 | $1,791,334 | 3.5 |
| Commercial Foodservice | $515,668 | 1.5 | $1,931,387 | 3.8 | $614,115 | 1.7 |
| Energy Education Program | $1,860,069 | 1.8 | $3,842,461 | 7.1 | $1,860,070 | 1.8 |
| Portfolio Management/Admin | -$50,718 | N/A | $0 | N/A | -$50,718 | N/A |
| **Totals** | **$5,379,470** | **1.69** | **$14,371,953** | **2.7** | **$6,583,425** | **2.3** |

| Northern Nevada - PROGRAM PORTFOLIO (3 Years) | | | | | | |
|---|---|---|---|---|---|---|
| | Total Resource Cost | | Participant Cost Test | | Utility Cost Test | |
| **PROGRAMS** | NPV | B/C | NPV | B/C | NPV | B/C |
| Residential Incentives | $51,800 | 2.3 | $83,174 | 2.9 | $53,998 | 2.5 |
| Residential New Construction | $305,487 | 2.7 | $464,309 | 3.2 | $337,684 | 3.3 |
| REDI | -$17,915 | 0.6 | $13,797 | 3.0 | -$38,775 | 0.2 |
| Commercial Incentives | $653,856 | 2.5 | $891,436 | 3.0 | $828,693 | 4.3 |
| Commercial Foodservice | $426,497 | 2.5 | $716,680 | 3.7 | $464,136 | 3.0 |
| Energy Education Program | $47,259 | 1.1 | $473,376 | 8.5 | $47,259 | 1.1 |
| Portfolio Management/Admin | -$261,038 | N/A | -$261,038 | N/A | -$261,038 | N/A |
| **Totals** | **$1,205,946** | **2.0** | **$2,381,734** | **2.5** | **$1,431.958** | **2.5** |

**AFFIRMATION OF VALERIA S. ANNIBALI**

Pursuant to NAC 703.710, Valeria S. Annibali affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 15th day of September, 2025

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VALERIA S. ANNIBALI

Draft Notice

**PUBLIC UTILITIES COMMISSION OF NEVADA**
**DRAFT NOTICE**
**(Applications, Tariff Filings, Complaints, and Petitions)**

Pursuant to Nevada Administrative Code ("NAC") 703.162, the Commission requires that a draft notice be included with all applications, tariff filings, complaints and petitions. Please complete and include **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(5)(a)):

**Southwest Gas Corporation (Southwest Gas) submits its Application for approval of its Nevada Triennial Resource Plan pursuant to Nevada Revised Statutes (NRS) 704.991 and proposed Nevada Administrative Code (NAC) 704.961 through 704.9708.**

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(5)(b)):

**Southwest Gas Corporation (Southwest Gas or Company).**

A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(5)(c)):

**The Nevada Triennial Resource Plan provides information concerning existing and planned facilities, as well as information regarding its planned projects for the upcoming three-year period in order to continue to provide safe and reliable natural gas service at a reasonable and prudent cost to the utility and customers. Southwest Gas also includes information regarding already approved projects and ongoing projects as well. Southwest Gas seeks Commission acceptance of the application as filed under the proposed NAC 704.961 through 704.9708, inclusive. There are no effects on customers or customer rates resulting from this filing.**

A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1):

**A consumer session is not required.**

If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

| Gas Tariff No. | PUCN Sheet No. | Section |
|---|---|---|
| 7 | 141 | Rule No. 1 |
| 7 | 141A | Rule No. 1 |
| 7 | 215 | Rule No. 16 |
| 7 | 216 | Rule No. 16 |
| 7 | 217 | Rule No. 16 |