ORIGINAL

0000168793

RECEIVED
AZ CORP COMMISSION
DOCKET CONTROL

2016 MAR 2 PM 3 30

BEFORE THE ARIZONA CORPORATION

COMMISSIONERS

DOUG LITTLE - Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE PROPOSED AMENDMENTS OF THE PIPELINE SAFETY RULES A.A.C. R14-5-202, R14-5-203, R14-5-204, R14-5-205, AND R14-5-207.

DOCKET NO. RG-00000A-15-0098

NOTICE OF FILING STAFF RESPONSES TO PROCEDURAL ORDER

Staff hereby provides notice of filing the attached Staff Responses to the questions presented in the January 28, 2016 procedural order in regards to the above captioned matter.

RESPECTFULLY SUBMITTED this 2nd day of March, 2016.

Charles H. Hains
Attorney, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 2nd day of March, 2016, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
DOCKETED
MAR 02 2016
DOCKETED BY

Copy of the foregoing mailed this 2nd day of March, 2016, to:

Robert E. Marvin, Division Director
Safety Division
2200 North Central Avenue, Suite 300
Phoenix, Arizona 85004

Jennifer Crapisi
Abbott Laboratories
1250 West Maricopa Highway
Casa Grande, Arizona 85193

James Payne
Alliant Gas
2000 East Frontage Road
P.O. Box 3025
Page, Arizona 86040

James Payne
Alliant Gas
200 West Longhorn Road
Payson, Arizona 85541

Joseph Covello
ALT – Applied Technologies
5499 West Needle Mountain Road
Topock, Arizona 86436

Johnny Penrod
Arizona Public Service
4606 West Hadley
P.O. Box 53999
Phoenix, Arizona 85043

Scott Vickers
Calpine South Point
3779 Courtwright Road
P.O. Box 5619
Mohave Valley, Arizona 86440

Frank McRae
City of Mesa
640 North Mesa Drive
P.O. Box 1466
Mesa, Arizona 85211-1466

Justin Burnett
City of Safford Utilities
405 West Discovery Park Blvd.
Safford, Arizona 85546

Kevin T. Hagerick
City of Willcox
101 South Railroad, Suite B
Willcox, Arizona 85643

Joseph Jessop
Colorado City
320 East Newel Avenue
P.O. Box 840809
Hildale, Utah 84784-0809

Terry Rigoni
Copper Market Gas
P.O. Box 245
Bagdad, Arizona 86321

Tom Steeper
Desert Gas Services
50200 Colorado River Road
Ehrenberg, Arizona 85334

Ray Latchem
Desert Gas Services
1709 Utica Square, Suite 240
Tulsa, Oklahoma 74114

Steve Lunt
Duncan Valley Electric/Gas Division
P.O. Box 440
379597 AZ HWY 75
Duncan, Arizona 85534

Tom Meek
El Paso Energy
2 North Nevada Avenue
Colorado Springs, Colorado 80903

Steve Lines
Graham County Utilities, Inc.
9 West Center Street
P.O. Drawer B
Pima, Arizona 85543

Brian Jaconi
Havasu Springs Resort
2581 Highway 95
Parker, Arizona 85344

Kenny Weickum
Ikard and Newsom
4359 US HWY 64
Kirtland, New Mexico 87419

Steve Marositz
Kinder Morgan Energy Partners, LP
2319 South Riverside Avenue
Bloomington, California 92316

Gary Simmerman
Mineral Park Inc.
7033 East Greenway Parkway, #120
Scottsdale, Arizona 85254

Joe Campbell
Mineral Park Inc.
8275 North Mineral Park Road
Golden Valley, Arizona 86413

Patrick Scott
Mojave Pipeline
5499 West Needle Mountain Road
Topock, Arizona 86436

Brandon Matthews
Pimalco Aerospace Aluminum
6833 West Willis Road, Box 5050
Chandler, Arizona 85225

Kevin Shaw
Palins LPG Services LP
14702 West Olive Avenue
Waddell, Arizona 85355

Rick Aragon
Questar
1215 South Lake Street
Farmington, New Mexico 87499

Eric DeBonis
Southwest Gas Corp.
Corporate Office
5241 Spring Mountain Road
Las Vegas, Nevada 89150

Jim Lantto
Southwest Gas Corp.
Engineering Staff/Arizona Compliance
3401 East Gas Road
P.O. Box 26500
Tucson, Arizona 85726

Shawn Brink
Southwest Gas Corp.
Central Arizona Division
9 South 43rd Avenue
P.O. Box 52075
Phoenix, Arizona 85072-2075

Mark Hingstrum
Southwest Gas Corp.
Southern Arizona Division
3401 East Gas Road
P.O. Box 26500
Tucson, Arizona 85726

Otis Williams
Swissport Fueling, Inc.
4200 East Airlane Drive
Phoenix, Arizona 85034

Nathan Hlavaty
Transwestern Pipeline
8001 Jefferson N.E.
Albuquerque, New Mexico 87113

Paul Huber
Tuba City School District #15
P.O. Box 67
Tuba City, Arizona 86045

Nathan Shelley
Unisource Energy Services
2901 West Shamrell Blvd., #110
Flagstaff, Arizona 86001

John Richardson
Valle Air Park
801 South State HWY 64, Space 100
Valle – Williams, Arizona 85007-2927

William Stephens
City of Benson Gas
160 South Huachuca
Benson, Arizona 85602

Bob Stone
Gila River, L.P.
1250 East Watermelon Road
Gila Bend, Arizona 85337

Ken Leier
North Baja Pipeline LLC
50600 Colorado River Road
P.O. Box 323
Ehrenberg, Arizona 85334

Jeff Hanenburg
Southwest Gas Corp.
Central Arizona Division
East Region
5705 South Kyrene Road
Tempe, Arizona 85283-1729

Fausto Luna
Remote Tank Farm
250 North 55th Avenue
Phoenix, Arizona 85043

Phil Priebe
Zapco Energy Tactics Corp.
7501 South Swan Road
Tucson, Arizona 86706

Roseann Osorio

SUPPLEMENTAL STAFF REPORT
SAFETY DIVISION, PIPELINE SAFETY SECTION
ARIZONA CORPORATION COMMISSION

PROPOSED RULEMAKING ON PIPELINE SAFETY RULES

DOCKET NO. RG-00000A-15-0098

STAFF RESPONSE TO PROCEDURAL ORDER

March 2, 2016

STAFF ACKNOWLEDGEMENT

The Staff Response to Procedural Order for Proposed Rulemaking on Pipeline Safety Rules, Docket No. RG-00000A-15-0098, was the responsibility of the Staff member listed below.

FOR ROBERT MILLER

Robert Miller
Pipeline Safety Manager

In the January 28, 2016 procedural order, a number of questions were posed to Staff regarding Staff's written responses to questions filed in this docket on January 19, 2016 by Spectrum LNG. Below, Staff repeats the questions provided in the procedural order and, in turn, provides its response to each question.

1. **What are the technologies available to non-destructively test welds as required under R14-5-202(T)?**

   The standard methods for conducting non-destructive testing are liquid penetrant, magnetic particle, radiography (x-ray), and ultrasonic. These testing methods are recognized by the following standards:

   - National Fire Protection Association (NFPA) Standard 59A (Standard for the Production, Storage, and Handling of Liquefied Natural Gas – 2001 Edition). The relevant excerpted portion is attached as Attachment A.

   - American Society of Mechanical Engineers (ASME) Standard B31.3 (Process Piping – 1996 Edition). The Relevant excerpted portion is attached as Attachment B.

   Per NFPA 59A paragraph 6.6.4 (Inspection Criteria), "Nondestructive examination methods, limitations on defects, the qualifications of the authorized inspector, and the personnel performing the examination shall meet the requirements of ASME B31.3, Process Piping, Sections 340 and 344."

   Per ASME B31.3 paragraph 344, magnetic particle, liquid penetrant, radiograph and ultrasound are all recognized methods of nondestructive examination.

   The NFPA standard is incorporated by reference into Title 49, CFR Part 193 per 49 CFR Part 193.2013. Further, Part 193.2301 states that each LNG facility constructed after March 31, 2000 must comply with the requirements of this part and of NFPA 59A.

2. **What is the estimated cost to test a weld using each of the technologies identified in response to question 1?**

   Based on estimated cost from three Arizona testing laboratories[1], the estimated costs for each method of nondestructive testing are set out below. By way of explanation, in Staff's experience, it takes approximately a half hour to an hour to set up the portable testing equipment. The time varies based on the particulars of the testing methodology being performed, as well as the size of the pipe. A full test of a weld takes between 10 to 30

[1] Staff made pricing inquiries of Canyon State Inspection Services, Western Technologies, and Phoenix National Laboratories. Staff also contacted Niagara Testing (Tucson) but they do not provide radiographic testing. Niagara's pricing for Ultrasound, Magnetic Particle and Liquid Penetrant were comparable with the offerings of the three full service laboratories.

minutes depending on conditions in the field and the testing method being used. Generally, radiographic testing takes the longest time and dye penetrant and magnetic particle testing require the least time to perform per weld. Owing to the variable amount of time to perform a test for a weld, testing facilities uniformly charge by the hour rather than on a per weld basis.

All of the testing methodologies are priced on the basis of unlimited welds examined per hour. For the two LNG facility operators in Arizona, both of which are located outside of the vicinity of any of the testing services, the testing services will charge a full day regardless of the actual hours the testing required. Thus a full eight hour day's labor charge should be assumed in all cases and will produce a labor cost of between $600 and $1,160 per day for one technician. Additionally, all services include a flat rental charge for the mobile testing laboratory and darkroom facilities. This is approximately $700 per day on average by all of the service providers in Arizona. The variable costs relate to travel expense, per diem for the testing crew and consumable testing materials such as film. Additionally, the costs relating to the specific testing methodologies are set out further below:

- Radiography: Labor costs approx. $145/technician per hr. for unlimited welds shots. The average range for film costs is between $36.00 per weld (2 inch pipe size) and $41.00 per weld (6 inch pipe size). There is also a $135 per technician per day for per-diem, and $0.75 per mile for the round trip.
- Ultrasonic: Labor costs approx. $80/technician per hour (includes unlimited welds inspected for that hour), plus per-diem and mileage rates listed above.
- Liquid penetrant: Labor costs approx. $75/technician per hour (includes unlimited welds tested for that hour), $15 per can of liquid penetrant used, plus the same per-diem and mileage rates above.
- Magnetic particle: Labor costs approx. $75/technician per hour (includes unlimited welds tested for that hour), approx. $35 per day for materials used, plus per-diem and mileage costs as listed above.

Staff would observe that, in its experience, the time to perform a weld exceeds the time necessary to perform any of the approved nondestructive testing methodologies to examine the weld. Welds such as those performed to connect the methane compressor facility at issue in the Staff Complaint filed in Docket No. G-20923A-15-0030 would average 45 minutes to an hour per weld to perform absent unusually difficult working conditions or a more technically challenging weld. Consequently, it can be anticipated that under most circumstances nondestructive testing will be more than able to keep pace of normal welding activity that is being performed. In the event that total project welding will require more than a full day to perform, it stands to reason that it may result in additional days that the testing services need to be available as well.

Because the existing rule already requires 30 percent of each day's welds be nondestructively tested, and the major cost that will be experienced is the labor rate that will be charged at a full eight hour day regardless of the number of welds examined, the major difference in cost to perform testing under the existing requirement and under the proposed rule revision will be the incidental cost of additional consumable testing materials such as film or liquid penetrant. In the event that a large number of welds are being performed on a given day, the testing cost will therefore witness an increase due to increased consumable materials used. However, it is conceivable that total testing costs could actually *decrease* because, rather than maintaining testing crews in place each day for which welds are performed to meet the 30 percent each day requirement, an operator could now concentrate all of the testing at the conclusion of all welding activity which may actually produce a more efficient testing process.

For example, currently if an operator were to perform 20 welds per day over the course of six days to complete a project, it would have to pay (8 hours x $145/hour (radiographic) + $700 = $1,860) flat daily charges each day across six days to perform six weld tests each day for a total of 36 nondestructive weld tests even though the testing crew may be capable of testing 30 welds per day. If the proposed rule change is adopted, the testing crew would only have to be present four days, thereby avoiding a third of the largest driver of testing expense. The savings increases in the event that more than one testing technician is required because the labor rate is the largest driver of expense and for each of the existing LNG facility operators, they will be charged in full days due to their remoteness from the testing services.

Costs should likewise not change significantly for a facility that has to perform a small number of welds either. Under the existing requirement, 30 percent of each day's welds must be tested even if it is only a handful of repair welds. As previously explained, the two Arizona LNG facility operators would still be subject to a full day's flat charge simply due to their location. Therefore, the cost difference would owe primarily to the increased consumable materials which Staff anticipates would be an incidental increase.

3. **To Staff's knowledge, has any other U.S. state, any other jurisdictional governmental entity, or any recognized industry standard-setting entity adopted a requirement substantially similar to that in R14-5-202(T) or more stringent than the requirement in 49 CFR 193-203? If so, please identify each such entity and provide a copy of the requirement adopted.**

To Staff's knowledge, no other US state or other jurisdictional governmental entity adopted a requirement like that which is being proposed in R14-5-202(T). As Staff noted in response to the January 19, 2016 comments of Spectrum LNG, Arizona's pipeline regulations are more typically proactive and ahead of other states.

However, Staff would note that the industry standards adopted by the CFR, and in turn adopted by reference by the Commission pursuant to A.A.C. R14-5-202(B) does provide for several types of welds that require 100 percent non-destructive testing of welds.

For example, NFPA 59A and ASME B31.3 provide:

- NFPA 59A, 6.6.3.2: "All circumferential butt welds shall be examined fully by radiographic or ultrasonic inspection." (There is an exception in the code for piping operating at temperatures above -20 degrees, which then requires at least 30 percent of each day's work to be non-destructively tested).

- NFPA 59A, 6.6.6.3: "All socket welds and fillet welds shall be examined fully by liquid penetrant or magnetic particle inspection."

- For piping that will see severe cyclic loading conditions, ASME B31.3, 341.4.3(b) requires that "all circumferential butt and miter groove welds, and all fabricated branch connection welds shall be examined by 100% radiography in accordance with paragraph 344.5, or by ultrasonic examination in accordance with paragraph 344.6. Socket welds and branch connection welds which are not radiographed shall be examined by magnetic particle or liquid penetrant methods in accordance with para. 344.3 or 344.4."

4. What caused Staff to conclude that it is necessary to require nondestructive testing of each weld performed on site at an LNG facility on newly installed, replaced, or repaired LNG pipeline or appurtenances?

In Staff's recent experience Staff has grown concerned by the quality of welding performed at facilities operated by LNG operators. These concerns are highlighted by the events that prompted the Staff Complaint in Docket No. G-20923A-15-0030. In that matter, the LNG facility operator performed a plant upgrade that involved the performance of 83 welds. The facility operator used two contracted welders to perform the welds. In the course of Staff's examination of the events leading to the upgrade's completion it became apparent that fewer than half of the required 30 percent of each day's welds were nondestructively tested. After the upgraded facility was brought into operation, additional remedial nondestructive testing was performed that revealed that out of 15 additionally tested welds, eight were faulty and upon rewelding, one of the repaired welds failed again. The greater than 50 percent failure rate was profoundly troubling to Staff.

Staff believes that had a 100 percent testing rate been in effect at the outset, the issue, which was ultimately attributed to one of the contracted welders being unqualified to perform the necessary work, would have been identified and rectified prior to bringing the newly added facility upgrade into operation. Welding and material failures have been identified as the second leading cause of pipeline failures in the nation. Moreover, the greatest risk of failure for a faulty weld is when it is first brought under full operating stress. Additionally, it is conceivable that it would be cheaper for a facility operator using contracted welders to identify and repair faulty welds prior to initiating operations. This is because the use of contracted welders whose services do not continue into the operating phase of the facility will necessitate bringing welders back to the worksite, whereas problems identified contemporaneous with the performance of the welding activity will occur while the welders are still on the job site and available to perform the necessary work.

Finally, although there are only two LNG facility operators in Arizona today, demand and the lack of natural gas storage may lead to growth in operations of this type. In particular, Staff can foresee demand for LNG peak-shaving plants in Arizona. *See e.g.* Docket No. G-01551A-14-0024 (application by Southwest Gas Corporation for pre-approval of ratemaking treatment relating to construction of a new LNG storage facility). Using this type of operation, pipeline operators liquefy natural gas when demand is low and store the LNG until demand is high. Storage is facilitated by the volume reduction accomplished through converting the natural gas to a liquid state. During periods of high demand, the LNG is vaporized and injected into either the gas transmission system or a distribution system. LNG plants like the one operated by Desert Gas are built similar in construction to peak-shaving plants but the LNG is used for vehicular fuel.

Also, the American Gas Association (AGA) noted (August 2013) that natural gas supplies nearly one-fourth of all of the energy used in the United States and that consumption of natural gas will increase 11 percent by 2030, according to the U.S. Department of Energy (DOE).

5. **Is Staff aware of any incidents of weld failure in LNG facility pipeline or appurtenances in the U.S. or any other country? If yes, please identify where and when the incident occurred, identify what entity or entities owned and operated the affected LNG facility pipeline or appurtenances, describe any findings regarding the cause of the incident and identify by whom those findings were made, and describe the physical and economic damaged caused by the incident.**

Staff is aware of one incident, explained below. Staff notes that LNG operators have only been required by US Department of Transportation's Pipeline and Hazardous Materials Safety Administration to file annual and incidents reports since 2011. Prior to this, there were no regulations that would require any LNG facility to report failures to any regulatory agency. This lack of reporting could lead to the mistaken impression that LNG is an industry with no failures. Additionally a large number of LNG facilities, mostly peak shaving operations, are still not regulated and reports of failures would go unreported unless they were large enough to garner media attention.

On December 18, 2014, at the Intermountain Gas LNG facility located near Nampa, Idaho, a weld located inside one of the tubes within an economizer component failed, resulting in a leak of natural gas at a pressure of 600 psi. The component filled with gas resulting in a rupture of the economizer box, which caused the operating personnel to activate the emergency shutdown of the LNG facility. There were no injuries or fatalities as a result of this incident but it did result in property damages in excess of $102,000 and a release of 185,000 cubic feet of natural gas. The incident report that was filed with PHMSA is attached as Attachment C.

6. **What is the operating pressure present in typical LNG pipeline and appurtenances used in the same manner as those at Desert Gas's LNG facility?**

According to Desert Gas's LNG plant operation and maintenance manual, the normal operating pressures prior to starting up the turbo-expanders will range from 15 psi at the LNG storage tanks up to 690 psi (discharge pressure at one of the methane compressors). The inlet pressure from the TransCanada pipeline facility that feeds the facility is approximately 630 psi.

7. **What is the operating pressure present in typical natural gas transmission pipelines for which 100 percent of new welds must be nondestructively tested?**

For intrastate natural gas transmission facilities, the maximum allowable operating pressure (MAOP) under 49 CFR Part 192.619 varies depending on the facility, from as low as 250 psi up to 837 psi.

8. **What are the temperatures present in typical LNG pipeline and appurtenances used in the same manner as those at Desert Gas's LNG facility, and what impact do those temperatures have upon pipeline and weld materials?**

Temperatures of the gas at an LNG plant typically range from as high as 60 degrees Fahrenheit down to the temperature where the gas condenses into a liquid which is -270 degrees (considered cryogenic). For an LNG plant like the one operated by Desert Gas in Ehrenberg, the process uses turbo-expanders which reduces the temperature of the gas to well below 0 degrees. However, the process only causes a portion of the total natural gas to condense into a liquid and the remaining gas must be re-compressed. This recompression process results in an increase in both pressure and temperature before being injected back into the main gas stream. This wide range of pressures and temperatures places thermal loads on the piping and the welds that join them together. CFR 49 Part 193.2505 requires LNG operators to have written cool-down procedures to enable the facility to gradually begin operations to avoid placing excessive thermal stresses on the pipeline and components.

9. **What are the temperatures present in the typical natural gas transmission pipelines described in question 7, and what impact do those temperatures have upon pipeline and weld materials?**

The temperatures in intrastate natural gas transmission facilities are generally around 60 degrees. Gas temperatures are normally higher when located downstream from compressor stations. At pressure reduction stations, the gas temperature will be somewhat reduced. Aboveground piping will undergo some degree of incidental thermal expansion and contraction due to the changing temperature of the surroundings.

10. **Why does Staff believe that it is not necessary to nondestructively test all welds made by a manufacturer of a prefabricated assembly being newly installed at an LNG facility) i.e., that it is only necessary to nondestructively test the welds made on**

site to connect the prefabricated assembly to the existing LNG facility pipeline and appurtenances)?

Components that are pre-manufactured are designed and manufactured to a design pressure and temperature rating are already subject to testing requirements established for the specific component. *See e.g.* 49 CFR 193.2303 (Construction Acceptance) "No person may place in service any component until it passes all applicable inspections and tests prescribed by this subpart and NFPA 59A." The testing requirements by component are various and provided throughout NFPA 59A. *See e.g.* NFPA 59A paragraph 3.4 describing the individual requirements for various categories of process equipment, an excerpt of which is attached as Attachment D.

Welding of factory manufactured components is conducted in controlled areas reducing the number of variables that could adversely affect the weld quality such as temperature, changing weather conditions, positioning of the pipe or appurtenance being welded, the direction of the weld, horizontal, vertical, up, down, rolled or fixed. These are all conditions that can be tightly controlled in a manufacturing process but not in a field situation.

Following construction, the component is then tested at the factory to ensure that the product meets the design specifications and ratings. As long as the manufacturer provides documentation to the LNG plant operator that states that the component (including the welds) was tested and meets the design requirements, then the welds on these manufactured components do not need to require additional non-destructive testing in the field.

11. **To Staff's knowledge, has any other U.S. state, any other jurisdictional governmental entity, or any recognized industry standard-setting entity considered and decided not to adopt either a requirement substantially similar to that in R14-5-202(T) or a requirement more stringent than the requirement in 49 CFR 193.203? If so, please identify each such state or entity and provide a copy of any documentation regarding the entity's consideration and decision not to adopt the requirement.**

Staff is unaware of whether any other U.S. state, or any other jurisdictional governmental entity, or any recognized industry standard-setting entity has considered yet refrained from adopting a requirement substantially similar to that proposed in R14-5-202(T). As previously stated, in Staff's experience, the Arizona Commission's Pipeline Safety program is typically ahead of other states.

Attachment A

6.4 Pipe Supports.

6.4.1 Pipe supports, including any insulation systems used to support pipe whose stability is essential to plant safety, shall be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure.

6.4.2 Pipe supports for cold lines shall be designed to prevent excessive heat transfer, which can result in piping restraints caused by ice formations or embrittlement of supporting steel. The design of supporting elements shall conform to ASME B 31.3, *Process Piping,* Section 321.

6.5* Piping Identification. Piping shall be identified by color-coding, painting, or labeling. Any existing company color code scheme for the identification of piping systems shall be permitted to be used.

6.6 Inspection and Testing of Piping.

6.6.1 Pressure Testing. Pressure tests shall be conducted in accordance with ASME B 31.3, *Process Piping,* Section 345. To avoid possible brittle failure, carbon and low-alloy steel piping shall be pressure tested at metal temperatures suitably above their nil ductility transition temperature.

6.6.2 Record Keeping. Records of pressure, test medium temperature, and ambient temperature shall be maintained for the duration of each test, and these records shall be maintained for the life of the facility or until such time as a retest is conducted.

6.6.3 Welded Pipe Tests.

6.6.3.1 Longitudinal or spiral welded pipe that is subjected to service temperatures below –20°F (–29°C) shall have a design pressure of less than $^2/_3$ of the mill proof test pressure or subsequent shop or field hydrostatic test pressure.

Exception: Pipe that has been subjected to 100 percent radiographic or ultrasonic inspection of the longitudinal or spiral weld.

6.6.3.2 All circumferential butt welds shall be examined fully by radiographic or ultrasonic inspection.

Exception No. 1: Liquid drain and vapor vent piping with an operating pressure that produces a hoop stress of less than 20 percent specified minimum yield stress shall not be required to be nondestructively tested if it has been inspected visually in accordance with ASME B 31.3, Process Piping, Section 344.2.

Exception No. 2: Pressure piping operating above –20°F (–29°C) shall have 30 percent of each day's circumferentially welded pipe joints nondestructively tested over the entire circumference in accordance with ASME B 31.3.

6.6.3.3 All socket welds and fillet welds shall be examined fully by liquid penetrant or magnetic particle inspection.

6.6.3.4 All fully penetrated groove welds for branch connections (as required by ASME B 31.3, *Process Piping,* Section 328.5.4) shall be examined fully by in-process examination in accordance with ASME B 31.3, Section 344.7, as well as by liquid penetrant or magnetic particle techniques after the final pass of the weld.

Exception: If specified in the engineering design or specifically authorized by the inspector, examination by radiographic or ultrasonic techniques shall be permitted to be substituted for the examinations required by 6.6.3.4.

6.6.4 Inspection Criteria. Nondestructive examination methods, limitations on defects, the qualifications of the authorized inspector, and the personnel performing the examination shall meet the requirements of ASME B 31.3, *Process Piping,* Sections 340 and 344.

Exception: Substitution of in-process examination for radiography or ultrasonics as permitted in ASME B 31.3, Paragraph 341.4.1, shall be prohibited.

6.6.5 Record Retention. Test records and written procedures required when conducting nondestructive examinations shall be maintained for the life of the piping system or until such time as a reexamination is conducted.

Records and certifications pertaining to materials, components, and heat treatment as required by ASME B 31.3, *Process Piping,* subparagraphs 341.4.1(c) and 341.4.3(d) and Section 346, shall be maintained for the life of the system.

6.7 Purging of Piping Systems.

6.7.1* Systems shall be purged of air or gas in a safe manner.

6.7.2 Blow-down and purge connections shall be provided to facilitate purging of all process and flammable gas piping.

6.8 Safety and Relief Valves.

6.8.1 Pressure-relieving safety devices shall be arranged so that the possibility of damage to piping or appurtenances is reduced to a minimum. The means for adjusting relief valve set pressure shall be sealed.

6.8.2 A thermal expansion relief valve shall be installed as required to prevent overpressure in any section of a liquid or cold vapor pipeline that can be isolated by valves.

6.8.2.1 A thermal expansion relief valve shall be set to discharge at or below the design pressure of the line it protects.

6.8.2.2 Discharge from such valves shall be directed to minimize hazard to personnel and other equipment.

6.9 Corrosion Control.

6.9.1* Underground and submerged piping shall be protected and maintained in accordance with the principles of NACE RP 0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems.*

6.9.2 Austenitic stainless steels and aluminum alloys shall be protected to minimize corrosion and pitting from corrosive atmospheric and industrial substances during storage, construction, fabrication, testing, and service. Tapes or other packaging materials that are corrosive to the pipe or piping components shall not be used. Where insulation materials can cause corrosion of aluminum or stainless steels, inhibitors or waterproof barriers shall be utilized.

Chapter 7 Instrumentation and Electrical Services

7.1 Liquid Level Gauging.

7.1.1 LNG Containers.

7.1.1.1 LNG containers shall be equipped with two independent liquid level gauging devices. Density variations shall be considered in the selection of the gauging devices. These gauges shall be designed and installed so that it is possible to replace them without taking the tank out of operation.

7.1.1.2 The container shall be provided with two high-liquid-level alarms, which shall be permitted to be part of the liquid level gauging devices. They shall be independent of each

Attachment B

ship, shall be examined in accordance with the applicable requirements of para. 341. The type and extent of any additional examination required by the engineering design, and the acceptance criteria to be applied, shall be specified. Joints not included in examinations required by para. 341.4 or by the engineering design are accepted if they pass the leak test required by para. 345.

(a) For P-Nos. 3, 4, and 5 materials, examination shall be performed after completion of any heat treatment.

(b) For a welded branch connection the examination of and any necessary repairs to the pressure containing weld shall be completed before any reinforcing pad or saddle is added.

341.3.2 Acceptance Criteria. Acceptance criteria shall be as stated in the engineering design and shall at least meet the applicable requirements stated below, in para. 344.6.2 for ultrasonic examination of welds, and elsewhere in the Code.

(a) Table 341.3.2 states acceptance criteria (limits on imperfections) for welds. See Fig. 341.3.2 for typical weld imperfections.

(b) Acceptance criteria for castings are specified in para. 302.3.3.

341.3.3 Defective Components and Workmanship. An examined item with one or more defects (imperfections of a type or magnitude exceeding the acceptance criteria of this Code) shall be repaired or replaced; and the new work shall be reexamined by the same methods, to the same extent, and by the same acceptance criteria as required for the original work.

341.3.4 Progressive Sampling for Examination. When required spot or random examination reveals a defect:

(a) two additional samples of the same kind (if welded or bonded joints, by the same welder, bonder, or operator) shall be given the same type of examination; and

(b) if the items examined as required by (a) above are acceptable, the defective item shall be repaired or replaced and reexamined as specified in para. 341.3.3, and all items represented by these two additional samples shall be accepted; but

(c) if any of the items examined as required by (a) above reveals a defect, two further samples of the same kind shall be examined for each defective item found by that sampling; and

(d) if all the items examined as required by (c) above are acceptable, the defective item(s) shall be repaired or replaced and reexamined as specified in para. 341.3.3, and all items represented by the additional sampling shall be accepted; but

(e) if any of the items examined as required by (c) above reveals a defect, all items represented by the progressive sampling shall be either:

(1) repaired or replaced and reexamined as required; or

(2) fully examined and repaired or replaced as necessary, and reexamined as necessary to meet the requirements of this Code.

341.4 Extent of Required Examination

341.4.1 Examination Normally Required. Piping in Normal Fluid Service shall be examined to the extent specified herein or to any greater extent specified in the engineering design. Acceptance criteria are as stated in para. 341.3.2 and in Table 341.3.2, for Normal Fluid Service unless otherwise specified.

(a) Visual Examination. At least the following shall be examined in accordance with para. 344.2:

(1) sufficient materials and components, selected at random, to satisfy the examiner that they conform to specifications and are free from defects;

(2) at least 5% of fabrication. For welds, each welder's and welding operator's work shall be represented.

(3) 100% of fabrication for longitudinal welds, except those in components made in accordance with a listed specification. See para. 341.5.1(a) for examination of longitudinal welds required to have a joint factor E_j of 0.90.

(4) random examination of the assembly of threaded, bolted, and other joints to satisfy the examiner that they conform to the applicable requirements of para. 335. When pneumatic testing is to be performed, all threaded, bolted, and other mechanical joints shall be examined.

(5) random examination during erection of piping, including checking of alignment, supports, and cold spring;

(6) examination of erected piping for evidence of defects that would require repair or replacement, and for other evident deviations from the intent of the design.

(b) Other Examination

(1) Not less than 5% of circumferential butt and miter groove welds shall be examined fully by random radiography in accordance with para. 344.5 or by random ultrasonic examination in accordance with para. 344.6. The welds to be examined shall be selected to ensure that the work product of each welder or welding operator doing the production welding is included.

They shall also be selected to maximize coverage of intersections with longitudinal joints. At least 38 mm (1½ in.) of the longitudinal welds shall be examined. In-process examination in accordance with para. 344.7 may be substituted for all or part of the radiographic or ultrasonic examination on a weld-for-weld basis if specified in the engineering design or specifically authorized by the Inspector.

(2) Not less than 5% of all brazed joints shall be examined by in-process examination in accordance with para. 344.7, the joints to be examined being selected to ensure that the work of each brazer making the production joints is included.

(c) Certifications and Records. The examiner shall be assured, by examination of certifications, records, and other evidence, that the materials and components are of the specified grades and that they have received required heat treatment, examination, and testing. The examiner shall provide the Inspector with a certification that all the quality control requirements of the Code and of the engineering design have been carried out.

341.4.2 Examination — Category D Fluid Service. Piping and piping elements for Category D Fluid Service as designated in the engineering design shall be visually examined in accordance with para. 344.2 to the extent necessary to satisfy the examiner that components, materials, and workmanship conform to the requirements of this Code and the engineering design. Acceptance criteria are as stated in para. 341.3.2 and in Table 341.3.2, for Category D fluid service, unless otherwise specified.

341.4.3 Examination — Severe Cyclic Conditions. Piping to be used under severe cyclic conditions shall be examined to the extent specified herein or to any greater extent specified in the engineering design. Acceptance criteria are as stated in para. 341.3.2 and in Table 341.3.2, for severe cyclic conditions, unless otherwise specified.

(a) Visual Examination. The requirements of para. 341.4.1(a) apply with the following exceptions.

(1) All fabrication shall be examined.

(2) All threaded, bolted, and other joints shall be examined.

(3) All piping erection shall be examined to verify dimensions and alignment. Supports, guides, and points of cold spring shall be checked to ensure that movement of the piping under all conditions of startup, operation, and shutdown will be accommodated without binding or constraint.

(b) Other Examination. All circumferential butt and miter groove welds and all fabricated branch connection welds comparable to those shown in Fig. 328.5.4E shall be examined by 100% radiography in accordance with para. 344.5, or (if specified in the engineering design) by 100% ultrasonic examination in accordance with para. 344.6. Socket welds and branch connection welds which are not radiographed shall be examined by magnetic particle or liquid penetrant methods in accordance with para. 344.3 or 344.4.

(c) In-process examination in accordance with para. 344.7, supplemented by appropriate nondestructive examination, may be substituted for the examination required in (b) above on a weld-for-weld basis if specified in the engineering design or specifically authorized by the Inspector.

(d) Certification and Records. The requirements of para. 341.4.1(c) apply.

341.5 Supplementary Examination

Any of the methods of examination described in para. 344 may be specified by the engineering design to supplement the examination required by para. 341.4. The extent of supplementary examination to be performed and any acceptance criteria that differ from those in para. 341.3.2 shall be specified in the engineering design.

341.5.1 Spot Radiography

(a) Longitudinal Welds. Spot radiography for longitudinal groove welds required to have a weld joint factor E_j of 0.90 requires examination by radiography in accordance with para. 344.5 of at least 300 mm (1 ft) in each 30 m (100 ft) of weld for each welder or welding operator. Acceptance criteria are those stated in Table 341.3.2 for radiography under Normal Fluid Service.

(b) Circumferential Butt Welds and Other Welds. It is recommended that the extent of examination be not less than one shot on one in each 20 welds for each welder or welding operator. Unless otherwise specified, acceptance criteria are as stated in Table 341.3.2 for radiography under Normal Fluid Service for the type of joint examined.

(c) Progressive Sampling for Examination. The provisions of para. 341.3.4 are applicable.

(d) Welds to Be Examined. The locations of welds and the points at which they are to be examined by spot radiography shall be selected or approved by the Inspector.

341.5.2 Hardness Tests. The extent of hardness testing required shall be in accordance with para. 331.1.7 except as otherwise specified in the engineering design.

341.5.3 Examinations to Resolve Uncertainty. Any method may be used to resolve doubtful indications. Acceptance criteria shall be those for the required examination.

342 EXAMINATION PERSONNEL

342.1 Personnel Qualification and Certification

Examiners shall have training and experience commensurate with the needs of the specified examinations.[1] The employer shall certify records of the examiners employed, showing dates and results of personnel qualifications, and shall maintain them and make them available to the Inspector.

342.2 Specific Requirement

For in-process examination, the examinations shall be performed by personnel other than those performing the production work.

343 EXAMINATION PROCEDURES

Any examination shall be performed in accordance with a written procedure that conforms to one of the methods specified in para. 344, including special methods (see para. 344.1.2). Procedures shall be written as required in the BPV Code, Section V, Article 1, T-150. The employer shall certify records of the examination procedures employed, showing dates and results of procedure qualifications, and shall maintain them and make them available to the Inspector.

344 TYPES OF EXAMINATION

344.1 General

344.1.1 Methods. Except as provided in para. 344.-1.2, any examination required by this Code, by the engineering design, or by the Inspector shall be performed in accordance with one of the methods specified herein.

344.1.2 Special Methods. If a method not specified herein is to be used, it and its acceptance criteria shall be specified in the engineering design in enough detail to permit qualification of the necessary procedures and examiners.

[1]For this purpose, SNT-TC-1A, Recommended Practice for Nondestructive Testing Personnel Qualification and Certification, may be used as a guide.

344.1.3 Definitions. The following terms apply to any type of examination.

100% examination — complete examination of all of a specified kind of item in a designated lot of piping[2]

random examination[3] — complete examination of a percentage of a specified kind of item in a designated lot of piping[2]

spot examination[3] — a specified partial examination of each of a specified kind of item in a designated lot of piping,[2] e.g., of part of the length of all shop-fabricated welds in a lot of jacketed piping

random spot examination[3] — a specified partial examination of a percentage of a specified kind of item in a designated lot of piping[2]

344.2 Visual Examination

344.2.1 Definition. Visual examination is observation of the portion of components, joints, and other piping elements that are or can be exposed to view before, during, or after manufacture, fabrication, assembly, erection, examination, or testing. This examination includes verification of Code and engineering design requirements for materials, components, dimensions, joint preparation, alignment, welding, bonding, brazing, bolting, threading, or other joining method, supports, assembly, and erection.

344.2.2 Method. Visual examination shall be performed in accordance with the BPV Code, Section V, Article 9. Records of individual visual examinations are not required, except for those of in-process examination as specified in para. 344.7.

344.3 Magnetic Particle Examination

Examination of castings is covered in para. 302.3.3. Magnetic particle examination of welds and of components other than castings shall be performed in accordance with Section V, Article 7.

[2]A designated lot is that quantity of piping to be considered in applying the requirements for examination in this Code. The quantity or extent of a designated lot should be established by agreeement between the contracting parties before the start of work. More than one kind of designated lot may be established for different kinds of piping work.

[3]Random or spot examination will not ensure a fabrication product of a prescribed quality level throughout. Items not examined in a lot of piping represented by such examination may contain defects which further examination could disclose. Specifically, if all radiographically disclosable weld defects must be eliminated from a lot of piping, 100% radiographic examination must be specified.

344.4 Liquid Penetrant Examination

Examination of castings is covered in para. 302.3.3. Liquid penetrant examination of welds and of components other than castings shall be performed in accordance with Section V, Article 6.

344.5 Radiographic Examination

344.5.1 Method. Radiography of castings is covered in para. 302.3.3. Radiography of welds and of components other than castings shall be performed in accordance with Section V, Article 2.

344.5.2 Extent of Radiography

(a) 100% Radiography. This applies only to girth and miter groove welds and to fabricated branch connection welds comparable to Fig. 328.5.4E, unless otherwise specified in the engineering design.

(b) Random Radiography. This applies only to girth and miter groove welds.

(c) Spot Radiography. This requires a single exposure radiograph in accordance with para. 344.5.1 at a point within a specified extent of welding. For girth, miter, and branch groove welds the minimum requirement is:

(1) for sizes ≤ DN 65 (NPS 2½), a single elliptical exposure encompassing the entire weld circumference;

(2) for sizes > DN 65 (NPS 2½), the lesser of 25% of the inside circumference or 152 mm (6 in.).

For longitudinal welds the minimum requirement is 152 mm (6 in.) of weld length.

344.6 Ultrasonic Examination

344.6.1 Method. Examination of castings is covered in para. 302.3.3; other types of components are not covered. Ultrasonic examination of welds shall be performed in accordance with Section V, Article 5, except that the alternative specified in (a) and (b) below is permitted for T-543.1.3 and T-547.1.1.

(a) When the basic calibration blocks have not received heat treatment in accordance with T-543.1.3 and T-547.1.1, transfer methods shall be used to correlate the responses from the basic calibration block and the component. Transfer is accomplished by noting the difference between responses received from the same reference reflector in the basic calibration block and in the component and correcting for the difference.

(b) The reference reflector may be a V-notch (which must subsequently be removed), an angle beam search unit acting as a reflector, or any other reflector which will aid in accomplishing the transfer.

(c) When the transfer method is chosen as an alternative, it shall be used, at the minimum:

(1) for sizes ≤ DN 50 (NPS 2), once in each 10 welded joints examined;

(2) for sizes > DN 50 and ≤ DN 450 (NPS 18), once in each 1.5 m (5 ft) of welding examined;

(3) for sizes > DN 450, once for each welded joint examined.

(d) Each type of material and each size and wall thickness shall be considered separately in applying the transfer method. In addition, the transfer method shall be used at least twice on each type of weld joint.

(e) The reference level for monitoring discontinuities shall be modified to reflect the transfer correction when the transfer method is used.

344.6.2 Acceptance Criteria. A linear-type discontinuity is unacceptable if the amplitude of the indication exceeds the reference level and its length exceeds:

(1) 6 mm (¼ in.) for $\overline{T}_w \leq$ 19 mm (¾ in.);

(2) $\overline{T}_w/3$ for 19 mm (¾ in.) < $\overline{T}_w \leq$ 57 mm (2¼ in.);

(3) 19 mm for $\overline{T}_w$ > 57 mm.

344.7 In-Process Examination

344.7.1 Definition. In-process examination comprises examination of the following, as applicable:

(a) joint preparation and cleanliness;

(b) preheating;

(c) fit-up, joint clearance, and internal alignment prior to joining;

(d) variables specified by the joining procedure, including filler material; and:

(1) (for welding) position and electrode;

(2) (for brazing) position, flux, brazing temperature, proper wetting, and capillary action;

(e) (for welding) condition of the root pass after cleaning — external and, where accessible, internal — aided by liquid penetrant or magnetic particle examination when specified in the engineering design;

(f) (for welding) slag removal and weld condition between passes; and

(g) appearance of the finished joint.

344.7.2 Method. The examination is visual, in accordance with para. 344.2, unless additional methods are specified in the engineering design.

Attachment C

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0522 EXPIRATION DATE: 10/31/2017

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	02/13/2015
	No.	20150001- 15006 (DOT Use Only)

INCIDENT REPORT – LIQUEFIED NATURAL GAS (LNG) FACILITIES

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
	Yes		

Last Revision Date:	
1. Operator's OPS-issued Operator Identification Number (OPID):	8160
2. Name of Operator	INTERMOUNTAIN GAS CO
3. Address of Operator:	
3a. Street Address	555 SOUTH COLE ROAD (POB 7608, 83707)
3b. City	BOISE
3c. State	Idaho
3d. Zip Code:	83709
4. Local time *(24-hr clock)* and date of the Incident:	12/18/2014 12:30
5. National Response Center Report Number:	Do Not Know NRC Report Number
6. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if reported):	
7. Incident resulted from:	
Unintentional release of commodity	Yes
Intentional release of commodity	No
Emergency shutdown	Yes
Reasons other than the above	No
- Describe:	
8. Commodity released: (select only one, based on predominant volume released)	Natural Gas while being handled in gaseous phase
- Other Commodity Name:	
9. Estimated volume of commodity released unintentionally - Thousand Cubic Feet (MCF):	185.00
10. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	
11. Estimated volume of liquid spilled to the ground (Barrels):	
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. General public	
12e. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. General public	
13e. Total injuries (sum of above)	
14. Was the LNG Facility shut down due to the incident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown	12/18/2014 01:30
14b. Local time LNG Facility restarted	
- Still shut down? (* Supplemental Report Required)	Yes

15. Was there an ignition?	No
16. Was there an explosion?	No
17. Number of general public evacuated:	0
18. Number of operator/contractor personnel evacuated:	0
PART B - ADDITIONAL FACILITY INFORMATION	
1. Facility Information:	
	LNG FACILITY / PLANT
Name of LNG Plant / Facility	NAMPA LNG FACILITY
NPMSLNG ID	NAMPA LNG
Plant / Facility Status	In Service
Plant / Facility Location	
State	Idaho
Process	
Liquefaction/Vaporization Rate (MMCF/D) at the time of the Incident	5
Number of Vaporizers in service at the time of the Incident	0
Total Capacity (MMCF/D)	5
LNG Source *(list all that apply)*	
Truck	
Railroad	
Ship/Barge	
Liquefaction	Yes
Interstate or Intrastate	Intrastate
LNG Storage	
Number of LNG Tanks	1
Volume of LNG in Storage at the time of the Incident (Bbls)	94,000
2. Type of LNG Plant / Facility: *(select all that apply)*	
Base Load	
Peak Shaving	Yes
Satellite	
Mobile / Temporary *(select the following based on use at time of Incident)*	
Intrastate	
Interstate	
Other	
Describe	
3. Function of LNG Plant / Facilityat the time and date of the Incident: *(select all that apply)*	
Marine Terminal *(select one or both)*	
Import Terminal	
Export Terminal	
Storage *(select one or both)*	Yes
With Liquefaction	Yes
Without Liquefaction	
Stranded Utility	
Vehicular Fuel	Yes
Nitrogen Rejection Unit or Other Special Use	
Describe:	
4. Item involved in Incident: *(select only one)*	
Item involved	Weld
- If Other Describe:	
PART C - ADDITIONAL CONSEQUENCE INFORMATION	
1. Estimated Property Damage:	
1.a Estimated cost of public and non-Operator private property damage	$0
1.b Estimated cost of Operator's property damage & repairs	$100,000
1.c Estimated cost of Operator's emergency response	$300
1.d Estimated other costs	$2,000
Describe	crane to remove Economizer and Company labor
1.e Total estimated property damage (sum of above)	$102,300
Cost of Commodity Released	
1.f Estimated cost of commodity released unintentionally	$555
1.g Estimated cost of commodity released during intentional and controlled blowdown	$0
1.h Total estimated cost of commodity released (sum of 1.f & 1.g above)	$555

PART D - ADDITIONAL OPERATING INFORMATION

1. Was a computerized Control System in place?	Yes
- If Yes:	
1.a Was it operating at the time of the Incident?	Yes
1.b Was it fully functional at the time of the Incident?	Yes
2. How was the Incident initially detected: *(select only one)*	Computerized Control System (such as alarm(s), alert(s), event(s), leak detection, temperature, pressure, etc.)
- If Other - *(Explain in PART G Narrative)*	

PART E - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Incident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	
1b. Specify how many failed:	
2. As a result of this Incident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART F - APPARENT CAUSE

Select only one APPARENT Cause of the Incident, and answer any questions on the right or below as indicated. Describe secondary, contributing, or root causes of the Incident in the narrative (PART G).

Apparent Cause:	F5 - Material Failure of Pipe or Weld

F1 - Corrosion Failure

External / Internal Corrosion	

F2 - Natural Force Damage

Natural Force Damage	
If Other Natural Force Damage,	
1. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
2. Were the natural forces causing the Incident generated in conjunction with an extreme weather event?	
2a. If yes, specify: *(select all that apply)*:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	

F3 - Excavation Damage

Excavation Damage	

F4 - Other Outside Force Damage

Other Outside Force Damage	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	

- If Other, Describe:	
- If Intentional Damage:	
3. Specify:	
- If Other, Describe:	
4. Did the Intentional Damage involve a breach of security?	
- If Yes, *(Explain fully in the PART G Narrative)*	
- If Other Outside Force Damage:	
5. Describe:	
F5 – Material Failure of Pipe or Weld	**Use this section to report material failures ONLY IF the "Item Involved in Incident" (from PART B, Question 4) is "In-plant Piping" or "Weld".**
1. The sub-case selected below is based on the following *(select all that apply)*:	
- Field Examination	Yes
- Determined by Metallurgical Analysis	
- Other Analysis	
- Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*	
Material Failure of Pipe or Weld	Construction-, Installation-, or Fabrication-related
If Low Temperature Embrittlement (due to a process fluid) 2. Was **insulation degradation** a factor in this failure?	
F6 - Equipment Failure	
Equipment Failure:	
- If Other Equipment Failure:	
1. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
2. Did this failure involve **Low Temperature Embrittlement** due to process fluids?	
3. Was **insulation degradation** a factor in this failure?	
F7 – Incorrect Operation	
Incorrect Operation:	
- If Other Incorrect Operation:	
1. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
2. Was this Incident related to: *(select all that apply)*	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
F8 - Other Incident Cause	
Other Incident Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART - G NARRATIVE DESCRIPTION OF THE INCIDENT

A weld on one of the tubes within the Economizer failed (pulled apart) leaking ~ 600 psig methane gas into the enclosed area of the Economizer. Boxed area of Economizer filled with gas and ruptured resulting in damage to the top and side of the box. The leaking gas resulted in a low pressure alarm on the CO_2 purification tower. Operators arrived on site and activated the liquefaction emergency shutdown.

It should be noted a SRC Report was filed on 12-23-14 in lieu of an Incident Report given the information and situation at that time. This Incident Report is being submitted at this time in addition to the SCR Report based on the recommendation of our Idaho PUC regulator. Monthly reports are being submitted to Jerry Kenerson at jerry.kenerson@dot.gov providing updated information as a new Economizer is being built and installed.

PART H - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Craig Chapin
Preparer's Title	Director - Engineering Services
Preparer's Telephone Number	208-377-6142
Preparer's E-mail Address	craig.chapin@intgas.com
Preparer's Facsimile Number	
Authorized Signature's Name	Craig chapin
Authorized Signature Title	Director - Engineering Services
Authorized Signature Telephone Number	208-377-6142
Authorized Signature Email	craig.chapin@intgas.com
Date	02/13/2015

Attachment D

2.7 Concrete Materials.

2.7.1 Concrete used for construction of LNG containers shall be in accordance with Section 4.3.

2.7.2 Concrete structures that are normally or periodically in contact with LNG shall be designed to withstand the design load, applicable environmental loadings, and anticipated temperature effects. Such structures shall include, but shall not be limited to, foundations for cryogenic equipment. They shall comply with the following:

(a) The design of the structures shall be in accordance with the provisions of 4.3.2.

(b) The materials and construction shall be in accordance with the provisions of 4.3.3.

2.7.3 Pipe supports shall comply with Section 6.4.

2.7.4 All other concrete structures shall be investigated for the effects of potential contact with LNG. If failure of these structures would create a hazardous condition or worsen an existing emergency condition by exposure to LNG, the structures shall be protected to minimize the effects of such exposure or they shall comply with 2.7.2(a) or (b).

2.7.5 Concrete for incidental nonstructural uses, such as slope protection and impounding area paving, shall conform to ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete.* Reinforcement shall be a minimum of 0.5 percent of the cross-sectional area of concrete for crack control in accordance with 2.2.1 of ACI 344R-W, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures.*

2.7.6 Concrete that is not constantly exposed to LNG and that has been subjected to sudden and unexpected exposure to LNG shall be inspected, and repaired if necessary, as soon as practical after it has returned to ambient temperature.

Chapter 3 Process Equipment

3.1 General. Process system equipment containing LNG, flammable refrigerants, or flammable gases shall be installed in accordance with one of the following:

(1) Outdoors, for ease of operation, to facilitate manual fire fighting, and to facilitate dispersal of accidentally released liquids and gases
(2) Indoors, in enclosing structures complying with Section 2.3 and 2.3.2

3.2 General. Process system equipment containing LNG, flammable refrigerants, or flammable gases shall be in accordance with one of the following:

(1) Outdoors, for ease of operation, to facilitate manual fire fighting, and to facilitate dispersal of accidentally released liquids and gases
(2) Indoors, in enclosing structures complying with 2.3.2 and 2.3.3

3.2.1 Pumps and compressors shall be constructed of materials suitable for the temperature and pressure conditions that might be considered.

3.2.2 Valving shall be installed so that each pump or compressor can be isolated for maintenance. Where pumps or centrifugal compressors are installed for operation in parallel, each discharge line shall be equipped with a check valve.

3.2.3 Pumps and compressors shall be provided with a pressure-relieving device on the discharge to limit the pressure to the maximum safe working pressure of the casing and downstream piping and equipment, unless these are designed for the maximum discharge pressure of the pumps and compressors.

3.2.4 Each pump shall be provided with an adequate vent, relief valve, or both, that will prevent over-pressuring the pump case during the maximum possible rate of cooldown.

3.3 Flammable Refrigerant and Flammable Liquid Storage. Installation of storage tanks for flammable refrigerants and liquids shall comply with NFPA 30, *Flammable and Combustible Liquids Code*; NFPA 58, *Liquefied Petroleum Gas Code*; NFPA 59, *Utility LP Gas Plant Code*; API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*; or Section 2.2 of this standard.

3.4 Process Equipment.

3.4.1 Process equipment shall be sited in accordance with Section 2.2.

3.4.2 Boilers shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section I, or CSA Standard B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, and pressure vessels shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1 or Division 2, or CSA Standard B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, and shall be code-stamped.

3.4.3 Shell and tube heat exchangers shall be designed and fabricated in accordance with the standards of the Tubular Exchanger Manufacturers Association (TEMA). The shells and internals of all exchangers shall be pressure tested, inspected, and stamped in accordance with the ASME *Boiler Pressure Vessel Code*, Section VIII, Division 1 or Division 2, or CSA B51, where such components fall within the jurisdiction of the pressure vessel code.

3.4.4* Installation of internal combustion engines or gas turbines not exceeding 7500 horsepower per unit shall conform to NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines.*

3.4.5 A boil-off and flash gas handling system separate from container relief valves shall be installed for the safe disposal of vapors generated in the process equipment and LNG containers. Boil-off and flash gases shall discharge safely into the atmosphere or into a closed system. The boil-off venting system shall be designed so that it cannot normally inspirate air during operation.

3.4.6 If internal vacuum conditions can occur in any piping, process vessels, cold boxes, or other equipment, the facilities subject to vacuum shall be designed to withstand the vacuum conditions or provision shall be made to prevent the development of a vacuum in the equipment that might create a hazardous condition. If gas is introduced to obviate this problem, it shall be of such composition or so introduced that it does not create a flammable mixture within the system.