IFO GROUP

Safety, Risk & Fire Consultants

Freeport LNG
Quintana Island, Texas

June 8, 2022 - Loss of Primary Containment
Incident Investigation Report

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NOTICE

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The information and conclusions in this Report are based on the information provided to IFO and IFO reserves the right to modify or change the information or opinions contained herein based on any new information or data obtained and any ongoing work relevant to this matter.

EXECUTIVE SUMMARY

Freeport Development LNG LP ("FLNG") operates a natural gas liquefaction facility located in Quintana, Texas ("Facility"). The Facility was originally designed and constructed to serve as an import facility to receive liquified natural gas ("LNG") for further distribution in the United States. As a result of significant changes taking place in the natural gas market after initial construction of the Facility was completed in 2008, the Facility was later modified to operate as an LNG export facility. As currently configured, the Facility includes three (3) LNG liquefaction trains for purposes of export. Train 1 was successfully commissioned and began commercial operations in December 2019, with Trains 2 and 3 commencing operations in January and May 2020, respectively. Combined, the three trains can produce over 15 million tons per annum ("mtpa") of LNG.

On June 8, 2022, at 11:28 a.m. central time, the Facility experienced a Boiling Liquid Expanding Vapor Explosion ("BLEVE") that resulted in the catastrophic failure of line [redacted] which in turn was immediately followed by a deflagration (vapor cloud explosion), referred to herein as the "Incident." This explosion and resulting fire caused significant damage to process piping at the Facility, requiring that the Facility cease operations until this assessment can be completed and any necessary corrective actions and repairs to any damaged equipment can be completed.

By way of background, the Regas area of the Facility, which includes the LNG tank farm and the marine loading operations, [redacted].

Several weeks later, [redacted]—[redacted]

More specifically, [redacted].

Then, at 8:21 a.m. on June 3, a Facility operator in the Control Room [redacted]; [redacted] through the time of the Incident five days later. Immediately after the [redacted], the temperature in this line began increasing, causing LNG in the line to start vaporizing to [redacted]. At 4:44 p.m. on June 3, a Facility operator [redacted] which also remained [redacted] through the time of the Incident.

Based on the operational configurations of the piping and valves that morning, [redacted] on June 3 resulted in the [redacted] The “boiling point” of LNG is -162°C (-259°F), which is considered a cryogenic temperature. Above this temperature (somewhat depending upon its actual composition), LNG begins to boil and convert from a liquid to a vapor.

[redacted]

[redacted]

On Monday, June 6, 2022, FLNG operators reported that line [redacted]—had moved significantly, including moving downward to the full span of the spring can installed on the line at the bottom of Tank [redacted]. By the afternoon of Tuesday, June 7, 2022, an engineer with FLNG had investigated this pipe movement and reported that it could be the result of a missing piping support. [redacted] This line was [redacted]

[redacted]

Figure 3 - [redacted]

By 4:43 a.m. on the morning of June 8, 2022, [redacted], releasing methane into the annular space of the piping [redacted]

By 8:21 a.m. on June 8, the temperature rose above the LNG critical temperature of -107.3°F. At that time, pressure in the line was also critical at greater than 717 pounds per square inch gauge ("psig"). We note that that contractors who were working in close proximity to Tank [redacted] during this time heard "banging" and other "strange" noises from the pipe rack and reported it to the FLNG Regas Control Room. An FLNG operator was sent to the area and did not observe or report any abnormal conditions.

At 11:28 a.m. on June 8, [redacted], resulting in the release of mixed-phase methane into the pipe rack and surrounding area, thereby causing the resulting loss of primary containment ("LOPC"). [redacted]. This initial piping failure and explosion, together with the subsequent displacement of and damage to other process piping, instrumentation, wiring and pipe rack structures, caused severe damage to additional process equipment and associated piping in adjacent areas within and near the pipe rack.

[redacted] IFO investigators arrived at the Facility on the morning of June 10, 2022, and assumed custody of the Incident scene.

This Report contains IFO's determination of the direct cause, root cause, and primary contributing causes of the Incident, all of which are detailed further below. Unless otherwise noted, all opinions set forth in this draft Report are stated to a reasonable degree of scientific certainty.

[redacted]

Figure 4 - General Location of the [redacted]

1. BUILDING AND SITE INFORMATION

1.1. Site Information

FLNG's Facility was designed and constructed in order to import / export LNG for international trade. The Facility as currently configured operates primarily as an LNG export facility. The Facility consists of three (3) Liquefaction trains; associated piping and vessels; three (3) 160,000 m3 LNG storage tanks; and two (2) ship berths. An upstream gas Pre-treatment Facility ("PTF") located at Oyster Creek produces liquefaction quality natural gas prior to sending the gas via the existing 42" pipeline to the Liquefaction Facility ("LQF") at Quintana Island.

The LQF trains receive dehydrated gas via the existing 42" pipeline to provide feed to the LNG precooling and liquefaction sections. The liquefaction process is based on Air Products and Chemicals, Inc.'s ("APCI") "propane, precooled, mixed component refrigerant process." Pursuant to this process, in order to convert the treated feed gas into LNG, the gas is first pre-cooled with propane refrigerant, at which point it is sent to the LNG train main cryogenic heat exchanger ("MCHE"). At the MCHE, the gas is cooled further inside heat exchanger tubes by a lower temperature mixed refrigerant flowing outside the tubes. As the feed gas flows up the tubes, it condenses by transferring heat to the liquid / vapor mixed refrigerant until it condenses into a liquid. The high-pressure LNG exiting the MCHE is depressurized through a hydraulic turbine (expander) and delivered through vacuum insulated LNG rundown piping to one of the LNG storage tanks (i.e., Tanks 1, 2, and/or 3). From the designated tank(s), the LNG is then pumped to one of the two (2) ship berths to be loaded onto LNG vessels for export. The LQF plant has a maximum LNG production capacity of approximately 870 billion standard cubic feet per year ("BSCF/year") based on processing about 892 BSCF/year of incoming feed gas from its upstream pre-treatment facility. Actual throughput and production capacity is generally lower than design capacity from year to year.

1.2. Facility Security, Life Safety, and Fire Protection Systems

A variety of security, fire protection, and life safety systems are utilized throughout the Facility.

With respect to Facility security, the Facility is manned 24/7 by security guards with tightly controlled access and the Facility complies with the United States Coast Guard's Maritime Security ("MARSEC") requirements.

Building construction is non-combustible with production structures generally constructed of reinforced concrete and structural steel. Enclosed, fire-rated emergency stairwells are provided for most of the occupied multi-story structures. Each building at the Facility is equipped with automatic fire detection systems with manual pull stations. Flame detection sensors are also installed in many process areas to provide early notification of fires.

[redacted]

The Facility has an initial emergency response team, typically staffed by plant operators and one supervisor on each shift for the initial response to incipient stage emergencies. There is also a trained emergency response team that is staffed by other operations, maintenance, and EHSS personnel. These individuals undergo National Fire Protection Association ("NFPA") approved industrial firefighting training as well as training in rescue, first aid, and hazmat. The Facility undergoes quarterly and annual emergency response drills. The Facility has two industrial fast attack trucks equipped with monitors that can be used to apply water or foam where needed. There are also a number of fixed fire monitors placed strategically throughout the Facility.

[redacted] Designated leadership, supervisory, operations, and support personnel at the Facility receive National Incident Management System ("NIMS") training to facilitate the effective management of emergencies. The Facility is also a member of the Brazosport Community Awareness & Emergency Response ("CAER") organization. CAER is a program that provides information to the community in the event an emergency should occur from one of their member companies. CAER also supports mutual aid responses between member organizations.

Figure 5 - Overhead View of Freeport LNG Facility – Quintana Island, Texas

2. EVENT TIMELINE

A timeline of key events surrounding the Incident is presented below. This timeline is based on IFO's direct investigation efforts, interviews with FLNG employees, a review of security video records, emergency response records, and a review of DCS data for the process equipment involved in the Incident. This timeline primarily focuses on the days June 3 to June 8, 2022, leading up to the time of the LOPC. A significant precursor event on April 26, 2022, which had a major impact on the cause of this Incident, is also discussed.

2.1. Events Leading to Loss of Primary Containment

Thursday, April 26, 2022

- [redacted] was tested by technicians employed by [redacted] with the assistance of an FLNG "B" operator called in to the Facility to work overtime to assist with PSV testing.

- [redacted]

[redacted] It is FLNG's stated policy that only FLNG operators will physically manipulate inlet isolation valves during PSV testing by PSV testing contractors, in this case, [redacted]

- [redacted] was one of [redacted] tested by [redacted] and signed off by this operator on April 26. See Appendix 12.1, "Tank Group PSV Report" and "[redacted] Relief Valve Test Report" dated April 08, 2022.
  - On June 11, 2022, IFO visually inspected [redacted] in situ and found the [redacted] ([redacted] (IFO also inspected the other PSVs inspected on April 26, 2022; [redacted])
  - On June 24, 2022, IFO interviewed the FLNG B operator who initialed "pass" following the [redacted] test. [redacted].
  - IFO also reviewed the Facility work orders and safe work permits generated and executed for the area between April 26 and June 8, 2022. IFO found no evidence of any work that would have required the manipulations of the [redacted] involved in the Incident.
  - As discussed further below, IFO believes that in the absence of any other credible scenario and supporting evidence, the most likely explanation for the [redacted] for [redacted] that resulted in [redacted] was the failure of the FLNG B operator to [redacted] conducted on April 26, 2022.

Friday, June 3, 2022

- At 6:13 a.m. on June 3, 2022, [redacted]. [redacted] ([redacted])
- [redacted]

[redacted]

- At 8:21 a.m. on June 3, 2022, [redacted] through the event). IFO notes that it is required to be [redacted]. [redacted] IFO was not able to determine why this [redacted] Immediately after [redacted] This is indicated in the data through significant increases in temperature at [redacted]. Prior to the [redacted] the pipe temperature was [redacted] (All pressures referred to in this document are calculated based on LNG conditions, discussed later. There was no pressure instrumentation on this line.)

- At 3:09 p.m. on June 3, 2022, [redacted] ([redacted]

- At 4:44 p.m. on June 3, 2022, the FLNG board operator [redacted] through the event. [redacted]) IFO was unable to determine why this [redacted] by the FLNG board operator. (8 minutes later at 4:52 p.m., [redacted]) After [redacted] the LNG trapped in this line slowly started to warm. The data shows a period of time (approximately 14 hours and 33 minutes) where some cooling during a rain event occurred due to lower ambient temperatures. Thereafter, the temperature on [redacted] steadily climbed. Overall, the inner pipe warmed from [redacted] Several mode changes at FLNG occurred during this time and are listed below, but had no impact on the Incident:
  - [redacted]
    - [redacted]
    - [redacted]
    - [redacted]
    - [redacted]

[redacted]

Monday, June 6, 2022 - Tuesday, June 7, 2022

- On Monday, June 6, 2022, an outside FLNG operator reported (e-mailed an FLNG supervisor at 10:28 a.m.) that piping downstream and connected to [redacted] had visibly moved. As a result of the movement, the piping had fallen off of its supports and damaged a spring can.

- By the end of the day on June 7, 2022, an FLNG engineer had visually inspected the piping and made an initial determination that the cause was likely a missing piping support and failed spring can which resulted in the piping movement. That FLNG engineer was unaware of the abnormal operating condition of [redacted] and the corresponding increase in pressure and temperature in the line caused by warming LNG. His inspection report to management noted the pipe was visibly “shaking slowly and slightly.”

    - IFO reviewed the DCS temperature data (Figure 12) for [redacted]. The data shows [redacted] started to heat up immediately after [redacted] on June 3. On June 4, [redacted] was exceeding the critical temperature and by June 6 late in the day it was over 70°F at the top and 20°F at the bottom of the riser. On June 8, temperature of [redacted] continued to heat to over 80° F at the top and 70°F at the bottom.

      [redacted]

[redacted]

Figure 6 – [redacted] [redacted]

Wednesday, June 8, 2022

- At 4:43 a.m. on June 8, 2022, the temperature data for Line [redacted] indicated that both expansion joints (where there are temperature indicators) [redacted] and a 17 minute cooldown period started [redacted]. LNG temperature in the line was [redacted] This initial cooldown indicates LNG was auto-refrigerating as it leaked through the broken expansion joint into the annulus. After the short cooldown, the temperature started increasing again [redacted] Pressure in the inner pipe had risen to [redacted] at the point the expansion joint is suspected to have failed. This higher heating rate was confirmed also with FLNG to indicate the loss of vacuum insulation in the VIP pipe annulus.

  NOTE: For calculation purposes, the temperature of LNG in line [redacted] is estimated to be 20°F cooler than the exterior pipe wall temperature. The LNG liquid was [redacted]

- Total internal pipe pressure when the internal expansion joints failed was the vapor pressure of LNG; [redacted] (using the noted -20°F correction for LNG temperature). The cooldown is thought to be indicative of gas expanding from the 18” interior pipe to the annulus with eventual loss of annulus vacuum. (An increase of system pipe volume was estimated in the calculation that resulted in a slight pressure loss in the 18” pipe as it depressured into the annulus vacuum.)

- At 5:01 a.m. on June 8, 2022, a higher rate of heat up started: [redacted]. Pipe temperature increased from [redacted] Pressure increased from [redacted]. (Included at the end of this period was a [redacted] The previous heat rate between June 4 and June 8 was an average of [redacted]

- At 7:19 a.m. on June 8, 2022, a rapid rate of heat rise started which lasted 4 hours and 9 minutes. The average heat rise was [redacted] The system was still subcritical (boiling still occurring) at the start of heat-up at [redacted].

- At approximately 8:25 a.m. on June 8, 2022, the temperature rose to above the critical temperature of -107.3°F and pressure was also near critical at 716.2 psig. Pressure as the temperature continued to rise after this point is calculated as a result of an energy balance and entropy balance conducted on the line [redacted] (Critical Pressure and Temperature as calculated with Hysys 12.1 Peng-Robinson real gas equation of state (fluid package) is -107.3°F and 717.1 psig.)

- At 8:29 a.m. on June 8, 2022, the FLNG operator switched to operating [redacted]

- At 11:28 a.m. on June 8, 2022, Line [redacted] failed after reaching supercritical temperatures approximately 3 hours earlier. At that time, the pipe wall temperature on the [redacted]hermocouple was [redacted], and [redacted] on the [redacted] thermocouple. Pressure as calculated through the energy and entropy balance was [redacted]

2.2. Weather Conditions at the Facility at the time of the LOPC event

Temperature:	86° F
Wind Direction:	SSE
Humidity:	77%
Dew Point:	78° F
Pressure:	29.93 inches

2.3. LOPC Event

The mechanical explosion (BLEVE) that took place at 11:28 a.m. on June 8, 2022 was the result of the over-pressurization of Line [redacted] causing it to fail catastrophically and cause a cascading series of multiple piping failures within the pipe rack. This explosion resulted in the release of mixed-phase LNG into the pipe rack and surrounding area. [redacted] This initial piping failure and explosion, together with the subsequent displacement of and damage to other process piping, instrumentation, wiring and pipe rack structures, caused severe damage to additional process equipment and associated piping in adjacent areas within and near the pipe rack.

The initial LOPC event continued for roughly 9 seconds and resulted in the atmospheric release of approximately 10,570 pounds of a flammable vapor comprised primarily methane, with trace materials making up the balance. The initial release of methane in gas phase was released from Line [redacted] along with a smaller release of approximately 2 barrels equivalent of LNG into the pipe rack containment. The turbulent dispersion of this flammable vapor into the open atmosphere served as the fuel for the resulting secondary vapor cloud explosion.

2.4. Dispersion of Methane After the LOPC Event

As the LOPC event progressed, a release of mixed phase methane (LNG) and gas dispersed into the pipe rack and the area directly above the pipe rack near Tank [redacted] from ruptures in Line [redacted], rapidly rising into the air with dispersal aided by wind from the SSE at 13 mph and ambient air temperature of 86°F. This release of methane was not from a single failure point of the piping but was instead unevenly released from various sections of Line [redacted] as the piping failed. As a result, the full 10,570 pounds of methane was not available to fuel the vapor cloud explosion that occurred above the pipe rack near Tank [redacted]. Given the large number of pipe section failures and their displacement from the pipe rack, propelled by escaping gas, it is believed that no more than ~50% or 5,285 pounds of methane was ultimately consumed in the visible fire ball with the balance of the fuel escaping into the atmosphere or consumed in a flash fire that was not observable on the available security cameras.

2.5. Vapor Cloud Explosion ("VCE")

The vapor cloud explosion in this event was fueled by the vaporized LNG escaping from the ruptures in [redacted] and generated minimal overpressure. The initial release of vaporized LNG was very buoyant and was ignited less than 9 seconds after the LOPC occurred with a visible fireball near Tank [redacted]. The vapor cloud explosion was a very brief deflagration event that failed to transition to a detonation due to the nature of the fuel involved, lack of confinement, and lack of sufficient fuel availability to sustain combustion within the fireball.

For the vapor cloud explosion calculation, it was estimated that 239,610 standard cubic feet (10,570 lb) of methane gas was released to the atmosphere of which it was estimated that 50% or 5,285 lb was consumed in the visible fireball, including a 2 barrels equivalent of liquid LNG that fueled the short lived pool fire in the pipe rack trench. See *Section 4.5 - Calculation of Mass of LNG as Basis for Vapor Cloud Explosion Calculations* for more information.

2.6. Secondary LOPC Events

The initial piping failure and explosion and subsequent displacement of and damage to other process piping and other structural elements severely damaged the integrity of certain other piping containing LNG, BOG, and Nitrogen. An observed secondary LOPC involving vaporizing LNG escaping from damaged 3" piping occurred at the Tank [redacted] area and continued until approximately 5:25 p.m. on June 8, 2022, until it was terminated by the [redacted]. This secondary LNG leak event did not ignite and was caused by a large failed section of Line [redacted] flying south through the pipe rack and striking other piping in the area.

[redacted]

Figure 7 – View of Secondary LOPC on [redacted]

[redacted]

2.7. Pool Fire in LNG Trench

Following the initial mechanical explosion (BLEVE) and the almost immediate ignition of the escaping methane in the area near Tank [redacted] to form a short-lived fireball, the remaining LNG from the ruptures in Line [redacted] drained across the deck of the pipe rack and into the elevated trench and then pooled. A secondary fire, initially fueled by this vaporizing LNG, in turn ignited other combustible materials within the pipe rack and the elevated LNG trench.

Specifically, the investigators noted thermal damage to electrical wire insulation and piping insulation in the pipe rack and cable trays in the area near the pool fire. In addition, heavy fire damage was noted to the concrete and concrete insulation in the area where the LNG pooled and burned. [redacted]

[redacted] The burning of these combustible materials was the likely source for the particulate laden smoke that was visible in this area following the initial LOPC and fireball. This fire continued to burn for approximately 45 minutes after the initial LOPC and was extinguished with the aid of fire water master streams applied from the ground near the pipe rack by emergency responders. The fire water master streams were supplied by both fixed facility fire monitors and monitors mounted on responding fire apparatus.

[redacted]

3. INVESTIGATION SUMMARY

3.1. Scene Investigation

On the afternoon of June 9, 2022, [redacted]. That day, initial preparations were made to mobilize to the site. IFO investigators arrived at the

Facility on the morning of June 10, 2022 and assumed custody of the Incident scene at that time.

Upon arrival, IFO received a thorough overview of the Incident's known facts from FLNG staff; reviewed pre-Incident photos and drawings of the Facility; completed a safety briefing; ensured that all incoming and outgoing process streams and other energy sources, such as utilities, were secured; and formulated a work plan.

IFO then identified the "secondary outer scene perimeter" for the initial search and survey. Investigators were briefed on protocol for marking, documenting, and recovering evidence. High priority was placed on documentation and recovery of any failed piping and process components that were displaced from their installed locations within the perimeter of the "initial primary investigation scene," specifically identified as the footprint of the Regas area bounded by the LNG Tank Farm and the Regas Process Area. Areas between the outer boundary of the primary scene perimeter and the outer boundary of the secondary scene perimeter boundary were searched in a grid pattern. Very few process piping sections and components were identified during these searches of the secondary search areas; those that were identified were documented and marked for recovery. No other process components of note were identified in the areas outside of the primary scene perimeter.

Following these efforts, IFO, on June 17, 2022, collapsed the Incident perimeter down into the confines of the "final primary investigation scene," defined as the footprint of the LNG Tank Farm and related pipe rack.

3.2. Investigation Scope and Methodology

The scope of IFO's investigation was to determine the cause and origin of the Incident and identify the root and contributory cause(s). IFO's investigation was conducted in accordance with international standards and NFPA 921 – *Guide for Fire and Explosion Investigations*. This Report provides the results of IFO's cause and origin investigation to date and details the direct, root, and primary contributory causes of the Incident. The investigation team used the Affinity Diagram, also known as a KJ diagram, for the root cause analysis. As one of the most common root cause analysis tools, the Affinity Diagram is used to generate and organize information relevant to the issue in question. It is typically used after brainstorming to sort large numbers of ideas and possible causes of an incident into groups. The Affinity Diagram allows investigators to identify the structure of big and complex factors that impact a problem or a situation. Also, it also segregates these factors into smaller groups (according to their similarity) and assists the team with identifying the root and contributing causes of incidents.

In this case, IFO's scene investigation consisted of the following primary tasks: scene inspection and examination; documentation of the scene; evidence identification, collection and removal; interviews of witnesses; documentation review and analysis; and identification of additional needed evidence to be collected from FLNG and other parties. Other investigation activities undertaken once the site-work was completed consisted of the following: additional witness interviews; reviews of additional documents, records, logs, files, engineering drawings and specifications; laboratory analyses of evidence; research of applicable regulations, codes, and standards; benchmarking activities; stakeholder briefings; and interactions with various local, State, and Federal authorities.

3.3. Evidence Identification, Collection, and Custody

IFO collected a large volume of evidence during the course of the investigation, including: physical specimens of process piping and equipment recovered from the pipe rack and immediate area around the LNG Tank Farm; photographs; video files; electronic and physical drawings; various security and operations logs; investigator notes and drawings; computer generated models; and laboratory analytical reports. IFO also reviewed certain FLNG documents (some of which are confidential and trade secret) and interviewed relevant FLNG employees.

IFO used a uniform method to identify physical evidence. Each piece of evidence was assigned a unique identifier. Evidence collected in the field was physically identified by either marking the evidence number directly on the specimen or the collection container and duly recorded on the master evidence log. Evidence that could not be immediately recovered was clearly marked, its location recorded, and then scheduled for later removal from the scene. A secure evidence holding area was identified and prepared at the Site. As evidence was recovered, especially of larger specimens, the evidence was moved to the holding area and stored until subsequent removal for analysis or transport for long term storage. IFO secured an offsite warehouse in Freeport, Texas for long term storage of physical evidence.

IFO maintained a positive chain of custody at all times for all physical evidence. No evidence was permitted to be moved or disturbed without one of the IFO investigation team members being physically present to observe. Smaller evidentiary items were removed from the scene by IFO by hand and transported either to the evidence holding area or to offsite secure storage. Larger specimens, specifically the applicable process piping sections, were removed from their locations by crane and transported by truck trailer to the offsite secure evidence warehouse for examination with all activities under the supervision of IFO. A member of the IFO investigation team was designated as the Evidence

Custodian. All evidence was collected, preserved, and labeled in accordance with the guidelines of ASTM E 1188, *Standard Practice for Collection and Preservation of Information and Physical Items by a Technical Investigator* (1995), and ASTM E 1459, *Standard Guide for Physical Evidence Labeling and Related Documentation* (1998).

As discussed in greater detail elsewhere, IFO has determined that the failure of piping section Line [redacted] was the primary cause of the LOPC Incident and the source of the subsequent explosion and fire. IFO recovered this piping (inner piping and outer shell) from the valve flange of [redacted] to the valve flange of [redacted]. The line was broken at the flanges of the valves as listed above while recovering all possible remnants of the line that was installed between those valves. [redacted] The section where [redacted] was installed was recovered intact with the isolation valves on the inlet and outlet sides of the pressure safety valve.

The piping sections between valves [redacted] was more than [redacted] in overall length as installed. Due to the damage sustained, specifically the partial ejection of the inner pipe from the outer shell, the combined length of actual piping recovered was approximately 1,000 feet. The piping was cut as necessary based on IFO's best professional judgment to facilitate removal of the sections from the pipe rack while avoiding welds and other areas of potential interest for metallurgical analysis. Piping flow direction and top-of-pipe location as found was marked on the piping sections.

In general, piping section lengths did not exceed approximately 25 feet in order to facilitate removal of the sections by truck to offsite secure storage. In some cases, piping sections were reduced to as little as 20 feet in order to facilitate their removal from the pipe rack.

Once all piping sections were removed and made accessible at the evidence warehouse, locations for material coupons and fracture surfaces were identified and then taken from the piping sections. The protocol for the metallurgical examination was reviewed and agreed upon with PHMSA and FERC representatives before the samples were formally identified and removed from the recovered piping sections.

3.4. Scene Examination and Documentation

The condition of the Incident scene was thoroughly recorded and documented by use of photography, video, and LiDAR mapping. The scene was photographed under different lighting conditions and from as many angles and perspectives as possible, including by aerial lift and unmanned aerial vehicle. The entire pipe rack area between the LNG tanks was mapped with LiDAR and drone photogrammetry and a 3D computer model of the scene was constructed.

3.5. Process Engineering Investigation Overview

On June 10, 2022, IFO began reviewing process information from the Facility, including P&IDs, PFDs, isometric drawings, and other process data, and then commenced a field inspection in the area where the Incident occurred. During this field inspection, IFO visually confirmed that approximately [redacted]

IFO's review of DCS data confirmed [redacted]. At that time, IFO also began a more detailed evaluation of available DCS data to better understand the circumstances that resulted in the Incident. IFO also began the additional task of verifying other valve positions and locating safety devices such as pressure safety valves ("PSVs").

On the morning of June 11, 2022, IFO found the [redacted], the [redacted].

During the course of the investigation, IFO's process engineering efforts focused on two key objectives: First, determine from an operations standpoint how and why line [redacted] and the circumstances that resulted in [redacted] These issues are addressed further below in Section 4 – Process Information. Second, determine the potential burst pressure of [redacted] (and related components) and estimate the amount of LNG released. Issues regarding this second objective are discussed further in Section 4. The burst pressure calculation and estimate of product contained in line [redacted] was used as a basis for the explosion overpressure calculations shown in Section 5 of this report.

3.6. Incident Investigation Team

Members of the IFO investigation team were carefully vetted for potential conflicts of interest with Freeport LNG, contractors engaged in work for Freeport LNG, and with suppliers of components used in the construction of the Facility. All members of the IFO investigation team were bound by confidentiality and non-disclosure agreements. Senior members of the investigation team were selected based upon their experience, training, and familiarity with the processes involved in the Incident.

The principal investigators for IFO at the Facility were as follows:

[redacted]

Collectively, these individuals have decades of fire, explosion, materials science, and engineering experience.

4. PROCESS INFORMATION

4.1. Overview

To determine the final pressure within Line [redacted] before the overpressure failure, IFO utilized Hysys Version 12.1 using the Peng Robinson real gas equation of state. IFO also performed a hydraulic calculation of the Line [redacted] piping system and its continuation piping from [redacted] through to the top of Tank [redacted] to arrive at the normal line pressure and determine if there were any significant frictional losses.

All of the DCS data used to evaluate the process was obtained from FLNG. The progression of events in Line [redacted] over a period of 5 days was then evaluated as 3 sequential systems as follows:

System 1: Line [redacted] System pressure was calculated as the vapor pressure of LNG at the known temperatures. [redacted]. The end of System 1 is just prior to the failure (break) of the first internal expansion joint.

System 2: [redacted] System pressure is calculated as vapor pressure of LNG at the known temperatures. The end of System 2 occurs just before the LNG critical temperature and pressure are reached.

System 3: Line [redacted] For this system, the initial state is defined as temperature and pressure just inside the supercritical region where Hysys (Peng Robinson) calculates the system initial specific entropy. Hysys is then used to: 1) estimate the final entropy, 2) calculate the enthalpy system change between initial and final and 3) iterate with another trial entropy such that the enthalpy and entropy both are balanced (converged). At this final known temperature point, with enthalpy and entropy converged, Hysys calculated a final pressure of 1,313 psig.

The history of the [redacted] from the inception of the Liquefaction Project procedures to the current procedures was reviewed in relation to the operation of the [redacted]. There were numerous formal and informal interviews with board operators concerning [redacted] Please see Section 4.7 for a detailed discussion of the Operating Mode Procedures and history.

[redacted]

Figure 10 - Process Flow Diagram – Process Area Focus of Investigation

4.2. Process Calculations and Diagrams

Figure 6 is the Process Flow Diagram showing the focus of this investigation. [redacted] Also, shown is location of the section of continuing pipe [redacted], the [redacted] which fell off its supports as discovered and reported by FLNG outside operator on June 6 at 10:28 a.m.

The following Appendices are attached to this report containing the process drawings and calculations:

[redacted]

4.3. Process Temperatures on Line [redacted] Before the LOPC

From the time the second [redacted] 4:44 p.m. on June 3, with the pressure relief device [redacted] showed increasing temperatures as is detailed in the timeline and seen on the [redacted] temperature graph. [redacted] transmitted final measurements just before the outer piping failed and are listed below:

[redacted]

The top two 18" inner pipe temperatures were above the LNG critical temperature of -107.3°F so theoretically there should have been no liquid in the pipe however, LNG in the bottom of the southwest end of Line [redacted] was estimated to be [redacted] According to FLNG, the skin thermocouples are believed to measure a temperature 20°F above the LNG fluid temperature, therefore LNG process temperatures used in the calculations have been adjusted to 20°F cooler than measured. As stated by FLNG, this could be due to inaccuracy of the temperature elements and/or heat gradient between the inner and outer walls of the pipe. To calculate the maximum expected burst pressure, the highest recorded temperature just before the pipe rupture in the vapor space (top thermocouple) was used for the calculations: [redacted] FLNG engineering personnel confirmed that the warmer measured temperatures were on the top of pipe and cooler temperatures were on the bottom. Figure 11 shows the Line [redacted] thermocouple temperatures during the event.

[redacted]

4.4 Calculation of Burst Pressure

In order to calculate the burst pressure, it was necessary to define the system. Three systems were defined.

System 1

System 1 consists of the [redacted] (not ruptured). The initial and final temperatures of this system obtained from DCS records were used to calculate the expected pressures at the initial and final conditions. System 1 was initiated the moment [redacted], [redacted]. It is a [redacted] with no mass entering or leaving, no pipe volume change, no work being performed (since a system cannot perform work on itself) and any elevation impact can be ignored (we are ignoring a 9.4 ft elevation rise in Line [redacted]). It is assumed that ambient heat from the surroundings causes the LNG temperature to rise and this was reflected in the DCS system inner pipe skin temperature measurements. The precise total mass of LNG in the pipe [redacted] is unknown. If liquid filled it would contain approximately 30,275 lb (698,388 SCF if converted to gas). The system was not liquid filled when the second valve ([redacted] and an estimation of the amount of vapor within is discussed at the end of this section.

Background: DCS data shows that on 6/3/22 between 6:22 a.m. and 6:31 a.m., [redacted] was transferred to Tank [redacted] as measured by [redacted]). Upstream of this flowmeter, [redacted] [redacted] [redacted] [redacted] {continuation of line [redacted]}.

[redacted] Due to the volume of this LNG transfer, the [redacted] was filled to the top of Tank [redacted] on 6/3/22. [redacted] at 8:21 a.m., Line [redacted] started to warm, resulting in Boil Off Gas (“BOG”) formation due to the LNG vapor pressure. Until valve [redacted], [redacted] [redacted] and [redacted]. As the LNG vaporized in Line [redacted] [redacted]. The amount of liquid estimated to be in Line [redacted] as a result of this backfilling and vaporization will be discussed later in this section.

Later, on 06/03 at 4:44 p.m., [redacted] and 8 minutes later at 4:52 p.m. [redacted]. IFO has not received an explanation (process reason) why [redacted]. [redacted], located downstream of [redacted] was also [redacted] 8 minutes later for no discernable reason.

To understand the normal operating pressure on Line [redacted] a hydraulic calculation was performed. The calculation shows that the frictional loss at the range of flows for different modes on the PFDs had little impact on Line [redacted] pressure. Pressure is determined by the static head of liquid in the riser putting backpressure on Line [redacted] of [redacted] This is considered the lowest pressure on Line [redacted] assuming the riser is full to the top of Tank [redacted].

[redacted], pressure in System 1 ([redacted]) very quickly increased to the vapor pressure of the warming LNG. As temperature rose from that point, pressure continued to increase along the vapor pressure curve in Line [redacted] Heat gain from the surroundings (the environment) was transferred to the liquid raising its temperature and through an increase of internal ener[redacted] System 1 when a rainstorm caused a flattening of temperature for 14 hours and 33 minutes between 6/3/22 9:43 p.m. and 6/4/22 12:16 p.m. Thereafter, for 96 hours – 25 min until 6/8/22 at approximately 4:42 a.m. [redacted] Figure 12 shows the vapor pressure curve for [redacted] LNG from normal operating to the critical point.

[redacted]

System 2

System 2 is still a [redacted] but, its volume has now increased (assuming all the expansion joints had failed) from [redacted] [redacted] when the annular space volume of the VIP pipe is added. Since the annular space is a deep vacuum, it is considered that no mass is added to or taken away from the system. Also, there is no influence on the energy balance due to work or elevation change. [redacted] The volume increase correction was made incrementally and assumed to occur from the time the expansion joints started to break until the LNG critical temperature of -107.3°F was reached. This volume increase has very little impact on the vapor pressure result and no impact on the final burst pressure as it is taken into account before the critical point was reached. The end of System 2 occurs just prior to the critical temperature. In System 2, [redacted]

Temperature data shows that on 6/8/22 at approximately 4:43 a.m., one or two expansion joints failed as both [redacted] experienced [redacted] It is expected that as LNG started to fill the annulus, when it contacted the hot outer pipe wall it heated quickly and if any liquid also passed through to the annulus it would immediately flash and the annulus pressure should increase. [redacted] The final warming of the pipe started on 6/8/22 at

7:19 a.m. [redacted] The LNG critical point of -107.3°F was exceeded on 6/8/22 at 8:26 a.m.

System 3

System 3 is again, [redacted] with no mass entering or leaving, no significant elevation difference and no work done. The system is the same physical pipe volume system as at the end of System 2. System 3 begins just inside the critical point (critical temperature is –107.3°F and critical pressure is 717.1 psig). To calculate the burst pressure in the supercritical region, an initial temperature was chosen as the first measured LNG temperature above the critical temperature from the DCS data, which is -106.97°F. An initial pressure = 719 psig, was chosen just beyond the critical point to calculate the initial specific enthalpy and initial specific entropy with Hysys. [redacted] The final burst pressure was obtained by converging the energy (enthalpy) balance and entropy balance according to the following:

Energy balance: $\Delta \underline{H} = \underline{Q}$ (Btu/lb) The heat input to the system = the change in enthalpy between the initial and final conditions.

Entropy balance: $\underline{S}_{(final)} = \underline{S}_{(initial)} + (\underline{Q}/T_f)*MW$

T_f = Final Temperature (°R), MW = Molecular Weight = [redacted]

The result of the entropy balance as calculated by Hysys determines the final pressure, with enthalpy also converged.

Using Hysys:

- [redacted]

The trial final entropy is input in Hysys with the LNG temperature and solved for the stream enthalpy. The enthalpy difference between initial and final conditions is then used in the above formula to calculate a new trial entropy. This iteration is repeated 2 or 3 times to arrive at an entropy that results in both entropy and enthalpy having converged between Hysys and the above entropy balance formula. When both have converged, the final pressure is also a result. See Appendix 12.3 for the Hysys results.

To determine the final pressure, one need only balance the entropy and enthalpy between the above formula and the final results for enthalpy and entropy in Hysys using the final temperature just before the pipe burst. There is no need to calculate the pressure of any intervening temperature points because they do not impact the final conditions. However, a number of additional pressure points were calculated especially at the higher temperatures to understand if a peak pressure might have been reached before the final temperature point. There were no intervening higher pressures than the final. [redacted]

[redacted]

[redacted]

[redacted]. Figure 13 summarizes the results of pressure calculations for Line [redacted]

[redacted]

4.5. Calculation of Mass of LNG as Basis for Vapor Cloud Explosion Calculations

[redacted].

[redacted]. [redacted] For the vapor cloud explosion calculation, it was estimated that 239,610 standard cubic feet (10,570 lb) of methane gas was released to the atmosphere, including a 2 barrels equivalent of liquid LNG.

4.6. Pressure Relief Valve Testing – April 26, 2022

FLNG lacked a formal PSV testing procedure that included a QA/QC process to ensure that PSV's are properly returned to service after testing with isolation valves car-sealed in their correct positions. At the time of the Incident, operators at FLNG were trained to assist with PSV testing by observing another, more experienced, operator and then expected to be able to perform oversight of contractor led PSV testing with no further training and without the aid of a written procedure or process. In addition, there was no formal car-seal procedure, no car-seal inventory, and no formal requirement to audit required car-seals in use throughout the units. Because of these deficiencies, human error, specifically the failure of an operator [redacted] after PSV testing, resulted in the failure of the facility personnel to discover that Line [redacted] was [redacted]

[redacted] After the testing was completed by the [redacted] technician [redacted] by the FLNG operator. Statements by FLNG operations personnel during interviews (not written practice or procedure) confirmed that outside contractors, including [redacted] technicians, are not permitted to open or close valves in the operating units; this duty is reserved exclusively to FLNG operators and contract operators.

IFO also reviewed the Facility work orders and safe work permits generated and executed for the area between April 26 and June 8, which yielded no evidence of any work which would have required the [redacted]

IFO was unable to identify any other plausible explanation for how or why the [redacted] other than human error during the PSV testing conducted on April 26, 2022. The process temperature data for Line [redacted] reviewed during the investigation clearly showed that [redacted] and available for pressure relief during the previous occurrence when Line [redacted] There is no evidence that the [redacted] between December 26, 2021 and April 26, 2022. Alternatively, we found no evidence in the process data that suggested that [redacted] and allowing the PSV to relieve pressure from the line between April 26 and June 4, 2022.

[redacted]

4.7. Operating Procedures for Modes of Operation – Tank Farm Operations

FLNG provided IFO with the operating procedures currently being used in the control room and with procedures written by the JV/FLNG early in the LQF project. These procedures include the following

1) Document No. [redacted], [redacted].
2) Document No. [redacted], [redacted].
3) Document No. [redacted], [redacted].
4) Document No. [redacted], [redacted].
5) Document No. [redacted], [redacted].
6) Document No. [redacted], [redacted].

[redacted]

[redacted]

There were 3 primary [redacted] involved in the incident: [redacted] The Mode Table below is a summary of the valve positions required for these valves for each of the [redacted] Modes of operation. Operator Choice valves are shown as “Op. Ch.” See *Figure 15 - Comparison of Modes of Operation Across the Various Procedures for LNG Tank Farm* below for more information.

[redacted]

[redacted] In interviews, the operators were asked why on June 4, [redacted] The operators all explained they did not know why this [redacted], but, several also stated that it might have been [redacted] Tank [redacted] maintenance was scheduled to begin on Monday, June 6, 2022. The repair work was to include repair work on two pump discharge hand valves ("HV") on the top of Tank [redacted]. IFO reviewed a P&ID highlighted by operations and used by maintenance to conduct the LOTO and other isolation work in preparation for this tank work. IFO also reviewed the safe work permit issued for this work and in no documents was it specified for [redacted]. On this basis, IFO concluded that this maintenance activity on Tank [redacted] was not a root or contributing cause of the Incident.

A number of revisions have been made regarding control valve permissives and culminating in the procedures currently in use, Reference Procedure #6 (16-Mar-2021). Two other procedures, Procedures #1 and #3, which were approved for use in 26-Jan-2021 and 6-Jan-2022 respectively, specifically set both [redacted] and [redacted] in four modes. IFO was informed during the investigation that Procedures #1 and #3 were not in use. A written procedure with [redacted] and [redacted] at the same time would not be good engineering practice considering the potential for overpressure because of increasing temperature and pressure in a closed system. The LNG industry would regard [redacted] as a "relief contingency" and provide at least a PSV as a safeguard but, also if this were to be operating practice, to install additional layers of safeguards prior to final dependence on a PSV.

[redacted]

[redacted]

Regarding the procedures listed in Figure 3, IFO conducted a detailed review of all the versions of the mode procedures and summarized the valve positions assigned to [redacted] and [redacted] for the various modes in each procedure. IFO asked FLNG engineers and operators but, was unable to get explanations for why the mode procedure revisions were necessary.

As noted in employee interviews, the control room “A” operators confirmed that the laminated mode sheet showing the Reference Procedure #6 XV positions is currently in use which was confirmed by IFO during visits to the Central Control Room. T[redacted] Control Room board operators had a range of answers to the following posed question: “If a valve is designated as ’Operator Choice’ does this indicate to you that you can switch the valve to any position you see as necessary and it is safe?” IFO was not provided with a consistent response to this question from the board operators.

4.8. Process Safeguards and Human Factors

There were a number of process safeguard and human safety factors that were relevant to the Incident. These are discussed in detail in this section.

First, we note that there were safeguards specifically designed for the VIP lines, which included internal and external pipe skin temperatures as follows:

- [redacted]
- [redacted]

See Figure 16 showing the External Pipe Skin Temperature data that was in operation leading up to the event. Three temperature points out of fourteen were operational and these are graphed in Figure 12 along with one malfunctioning point [redacted]. [redacted] appeared to be working but, the data of June 8 does not appear to indicate any expansion joint leaks were detected.

[redacted]

The internal pipe skin temperature instrumentation for line [redacted] are located as follows:

- [redacted]

The internal piping skin temperatures are used to monitor cool down to prevent large temperature differences between top and bottom of piping during cool down. IFO reviewed the data from these instruments retrieved from the DCS historian which showed the rise in temperature during the event. Although these temperatures are displayed on the control room console, they do not alarm audibly or visibly to the operator if temperatures exceed parameters. These alarms are instead logged as journal alarms. The control room operator is not alerted if there is a temperature excursion; as a result, from a process safety standpoint, these alarms do not serve as safeguards for the operation.

Also, IFO noted that the control board monitors are monochromic with most items colored black, grey, and white. As a result, it is difficult for board operators to discern the current status of equipment, such as valve position, at a glance. The numerical values are only faintly visible to operators on the screen and temperature values themselves are not clearly discernable. There are temperature signals visible above lines on the screen, but there is no indication which process lines those temperature signals are associated with because the lines are not labeled.

During our interviews, operators commented about "excessive alarms." Some operators even noted that there were alarms constantly indicating on equipment that had been placed out of service years ago. These circumstances apparently resulted in reported alarm fatigue, at least for some of the operators interviewed during the course of the investigation. IFO reviewed a week of alarm backlog (just prior to the event) in conjunction with the alarm first-out data for analysis and discussion with FLNG process engineering. There was general agreement among FLNG operators and engineers during formal and informal discussions with IFO that there are an excessive number of alarms.

The external pipe skin temperature instrumentation is utilized for leak detection. But once again, there are no audible or visible alarms available to warn operators. Also, [redacted]. [redacted] [redacted] were out of service and [redacted] was malfunctioning, either the result of the batteries being dead or some other malfunction when inspected after the Incident. Thus, these skin temperatures would have been unavailable to operators in the days leading up to and including the day of the Incident. The check of the data (Figure 16) on the [redacted] operating leak detection points showed no discernible temperature trend outside of normal except right up to the time of the 24" pipe rupture.

The control room screens have other limitations. For example, valves [redacted] are physically located over [redacted] from each other, but on one console screen they are shown within ¼ inch of each other. This visual representation could suggest to operators that the valves are close together in the field. Also, valve [redacted] is not shown, which is in parallel with and in close proximity to valve [redacted]

The only true safeguard on Line [redacted] for protection against overpressure was provided by the relief valve [redacted], which was the only PSV for this [redacted] line when valves [redacted] are closed. In this case, however, no additional safeguards were provided. It further appears that this scenario was not evaluated or considered during the previous Hazard and Operability Analysis ("HAZOP") Study.

4.9. VIP Pipe Temperature

Vacuum insulated pipe ("VIP") is a highly efficient way of keeping LNG cold when flowing through the process piping. However, when flow stops, FLNG process data clearly shows that the LNG within the pipe will begin to warm immediately.

When [redacted], the temperature of LNG within the line rose immediately (as detailed in the description of the event above). [redacted]. In the absence of flow, heat transfer immediately begins and the stagnant LNG starts vaporizing and generating BOG.

[redacted] As the piping warms, it expands and grows longer; likewise, the piping contracts as it cools. This thermal expansion and contraction impacts both the inner and outer expansion joints. If temperature and pressure are allowed to result in excessive expansion and contractive cycling, wearing of the expansion joints will occur due to cyclic stress cracking.

[redacted], with the exception of the availability of pressure relief provided by valve [redacted], which [redacted]

This illustrates again that LNG flow in VIP piping must be maintained at some minimum level to prevent excessive temperature swings that adversely impact the expansion joints and overpressure events.

A Mechanical Fabrication Data Book for each of the 9 VIP pipe segments was made available for IFO review by FLNG.

5. FIRE CAUSE AND ORIGIN

[redacted] on [redacted] deprived Line [redacted] of pressure relief protection. [redacted] eventually led to a [redacted]. This abnormal operating condition ultimately resulted in a mechanical explosion in the form of a BLEVE (Boiling Liquid Expanding Vapor Explosion) involving Line [redacted] on June 8, 2022,at approximately 11:28:21 a.m. The damage to the piping support structure and associated components indicates that the probable point of initiation(origin) for the BLEVE explosion was within the pipe rack near Tank [redacted].

The BLEVE in turn led to a LOPC (Lack of Primary Containment) of the line's flammable contents. This LOPC from Line [redacted] resulted in the atmospheric release of approximately 239,610 standard cubic feet (10,570 pounds) of a flammable vapor comprised primarily methane with some trace materials. The turbulent dispersion of this flammable vapor into the open atmosphere served as the fuel for the resulting secondary vapor cloud explosion.

The release continued for roughly nine (9) seconds when the escaping methane came into direct contact with and was ignited by open and damaged electrical conduits and circuitry in the pipe rack caused by the BLEVE. This ignition resulted in an unconfined deflagration explosion in close proximity to Tank [redacted]. The BLEVE in Line [redacted]. The maximum peak overpressure experienced by other nearby structures of interest, specifically the Regas Control Room and Old Maintenance Building, were modeled as a maximum of 1.8 psi at 385 feet and 1.1 psi at 495 feet, respectively. These results are closely aligned with the observed damage (or lack thereof) inflicted on the nearby LNG Tanks, structures, and process equipment.

The secondary vapor cloud explosion ignited following the LOPC was chemical in nature and generated minimal overpressure as the result of an exothermic reaction. Chemical reactions of the type involved in this explosion propagate in a reaction front away from the point of initiation. In addition, this explosion is classified as a combustion explosion due to the presence of a fuel (methane) with atmospheric air acting as an oxidizer. This explosion is further classified as a non-seated deflagration based on the apparent subsonic velocity of the flame front propagation through the fuel air mixture.

Witnesses in the area reported only the sound of the initial mechanical explosion caused by the BLEVE and resulting failure of Line [redacted]. Witnesses uniformly reported that they initially mistook the sound of the BLEVE as thunder. The investigation team located no evidence that the secondary vapor cloud explosion generated sufficient overpressure to create a perceptible blast wave. This is supported by our review of the available security videos which showed the initial

release of methane with rapid ignition and a visible fireball near Tank [redacted] that rapidly dissipated as the available fuel was exhausted. The vapor cloud explosion was a very brief deflagration event that failed to transition to a detonation due to the nature of the fuel involved, lack of confinement, and lack of sufficient fuel availability to sustain combustion within the fireball.
In order for a fire or explosion involving methane to occur, an adequate concentration of methane, the presence of an ignition source, and sufficient oxidizer (such as atmospheric oxygen) must be present at the same time. Methane has a fairly narrow flammability range (4.4% to 16.4% in air) and the MIE (Minimum Ignition Energy) required to ignite methane (0.28 mJ) (Crowl & Louvar, 2011) is low.

As noted above, the ignition source in this Incident is believed to have been electrical. Severely damaged electrical conduit with open wiring in contact across phases and with the neutral and ground, which was energized at the time of the Incident, was found in the immediate area of origin and would have served as a competent ignition source with available energy sufficient to ignite methane vapor. IFO's investigation team did not locate or identify any other competent ignition sources in the area of origin.

The overall characterization of the explosion damage in this event is assessed as "low order" as a function of the blast load applied to the exposed surfaces (rate of pressure rise, impulse, and peak pressure achieved in the event) and the strength of the confining structure, rather than the maximum pressures reached. Low order damage is characterized by structural elements bulged out or laid down, virtually intact, next to or inside the structure with associated debris that is generally large and moved short distances. Low order damage is produced when the blast load is sufficient to cause the failure of structural connections to large surfaces, such as walls or ceilings, but insufficient to thoroughly break up larger surfaces and accelerate debris and missiles to significant velocities. The open nature of the pipe rack framing provided only minimal confinement. Following the initial mechanical explosion (BLEVE) and the almost immediate ignition of the escaping methane in the area near Tank [redacted] to form a short-lived fireball, the remaining LNG from the ruptures in Line [redacted] drained across the deck of the pipe rack and into the elevated trench and then pooled.

A secondary fire, initially fueled by this vaporizing LNG, in turn ignited other combustible materials within the pipe rack and the elevated trench. Specifically, the investigators noted thermal damage to electrical wire insulation and piping insulation in the pipe rack and cable trays in the area near the pool fire. In addition, heavy fire damage was noted to the concrete insulation in the area where the LNG pooled and burned. The concrete on the bottom of the pipe rack [redacted]. The burning of these combustible materials was the likely source for the particulate laden smoke that was visible in this area following the initial LOPC and fireball. This fire continued to burn for approximately 45 minutes after the initial LOPC and was extinguished with the aid of fire water master streams applied from the ground near the pipe rack by emergency responders.

6. STRUCTURAL

Beginning on June 11, 2022, forensic structural engineers from IFO were at the Facility to observe and document the damage to the Facility's key structures and buildings. In particular, IFO conducted an evaluation of the damage to the pipe rack structure as well as the adjacent process platforms during the Incident. IFO also evaluated for potential damage the two buildings in the vicinity of the Incident—the re-gas control room and the old maintenance building.

A summary of the structural and equipment damage assessment is included in *Appendix 12.7 Structural and Equipment Damage Assessments*.

7. METALLURGICAL FAILURE ANALYSIS

KnightHawk Engineering, Inc. ("KHE") was retained by IFO to perform metallurgical testing on the materials of the [redacted] line involved in the Incident. A summary of their findings is provided below. Their full report is provided in *Appendix 12.8* of this report.

Metallurgical testing of the fracture surfaces of some (but not all) of the Line [redacted] expansion bellows found the presence of low cycle fatigue cracking, as demonstrated by:

(1) the presence of significant parallel secondary cracks;

(2) significant strain hardening;

(3) slip band formation with crack initiation;

(4) crack tip blunting, fracture surface rubbing; and

(5) the presence of fatigue striations.

Based on the expected time to fatigue crack initiation under low cycle fatigue conditions, and the distance of propagation of the fatigue crack, KHE estimates that approximately 10% of the fatigue life of the bellows was expended based on the metallurgical data and therefore fatigue is unlikely to have been a contributing cause of the Incident.

Metallurgical analysis of the some of the fracture surfaces of the bellows and all of the fracture surfaces non-bellows from line [redacted] showed that the failures were due to overload of the pipe, as is expected given the nature of the overpressure event and subsequent explosion. No additional failure modes were observed.

KHE performed positive material identification ("PMI") on the materials used to construct Line [redacted] and found no deviations in the metallurgical chemistry of the lines. The yield and tensile strengths of the lines were higher than expected for the materials of construction (mainly 304 stainless steel), while the total elongation was generally lower than expected. However, all of these deviations are consistent with the yielding of the line due to the overpressure event it experienced prior to the failure. Thus, KHE does not consider there to be any deviations from expectations with respect to the materials of construction.

KHE analyzed a location where there was a "bulge" on the inner diameter ("I.D.") of the inner pipe. KHE determined that the cause of the bulge was the presence of radial supports between the inner and outer pipe which constrained the expansion of the inner pipe during the slow increase in the inner pipe pressure.

KHE performed a hydrotest on the pressure safety valve ("PSV") associated with Line [redacted] The valve was found to release pressure between 212 and 215 PSIG, and the set pressure was found to be 225 PSIG. The PSV was not found to leak below 210 PSIG. Analysis of the PSV components revealed wear on the shaft of the spring side mating surface, but KHE does not believe that this wear was sufficient to compromise the function of the PSV.

8. CAUSAL DETERMINATION

The main purpose of IFO's investigation was to determine the Direct Cause, Root Causes, and Primary Contributing Causes of the Incident. IFO's causal determinations from its investigation are outlined below.

8.1. Direct Cause of the Incident

IFO determined the direct cause of the June 8, 2022 incident to be Line [redacted] which is believed to have occurred during the annual testing of that PSV on April 26, 2022. [redacted] This in combination with Line [redacted] on June 4, 2022 partially filled with liquid LNG by [redacted] created the potential for extreme over pressurization of Line [redacted]. [redacted], the line would have been protected from overpressure with no LOPC incident as a result. However, the [redacted]

[redacted] was heated by the surrounding environment causing a pressure of [redacted] to develop, resulting in a BLEVE and bursting of the pipe followed by a vapor cloud explosion.

Following the failure of line [redacted], IFO identified the cause of the explosion and fire to be contact between flammable vapor (methane) and an ignition source (open and damaged electrical conduits and circuitry) in the pipe rack following the LOPC, which resulted in a vapor cloud explosion and a small secondary pool fire on the northeast end of the pipe rack in the elevated LNG drainage trench.

Background of the Direct Cause

[redacted] by the assigned "B" Operator in order to allow testing of the PSV on April 26, 2022 resulted in the [redacted]rom pressure relief. After the testing was completed by the [redacted] technician, the most probable explanation for [redacted] to have occurred is: [redacted] by the FLNG operator. Statements by FLNG operations personnel during interviews confirmed that outside contractors, including [redacted] technicians, are not permitted to open or close valves in the operating units; this duty is reserved exclusively to FLNG operators and contract operators (this practice is not covered in a written procedure.)

IFO also reviewed the Facility work orders and safe work permits generated and executed for the area between April 26 and June 8, which yielded no evidence of any work which would have required [redacted] involved in the Incident.
IFO was unable to identify any other plausible explanation for how or why the [redacted] other than human error during the PSV testing conducted on April 26, 2022. Additionally, a review during the investigation of the temperature history of Line [redacted] clearly showed that the [redacted] from October 21, 2021 to December 26, 2021 (data shows the PSV was consistently relieving LNG to prevent pressure rising above 225 psig.) There is no evidence that the [redacted] between December 26, 2021 and April 26, 2022.

8.2. Root Causes of the Incident

Root causes of the June 8 incident are as follows:

8.2.1. Lack of PSV Testing Procedure and Lack of a Car Seal Program

FLNG lacked a formal PSV testing and quality assurance written procedure to ensure that PSVs are [redacted] At the time of the Incident, operators at FLNG were trained to assist with PSV testing by observing another, more experienced, operator and then expected to be able to perform oversight of contractor led PSV testing with no further training and without the aid of a written procedure. In addition, there was no formal car seal procedure, no formal car seal training, no car seal checklist/inventory process, and no formal requirement to audit car seals in use throughout the units.

8.2.2. Lack of Safeguards to Warn Operators of Increasing VIP Pipe Temperature

[redacted]

[redacted] The "leak detection" temperature points offered no safeguard even if alarmed.

Because [redacted] the operators in the control room were unaware that the LNG within the line was warming and exerting excessive pressure on the line and its components until the Incident occurred.

Therefore, from a process hazards analysis (PHA) standpoint, Line [redacted] was inadequately safeguarded with only PSV [redacted] to protect it from excessive pressure.

8.2.3. The Facility Operating Procedures Allow [redacted]

Section 4.7 includes a detailed discussion of the history of revisions to the FLNG Operating Procedures. [redacted]

More than one Control "A" Board Operator said they are not familiar with or had never seen this document. [redacted] As detailed in Section 4.7 it is possible, due to [redacted]

Several Control "A" Operators (including the two operators who [redacted]) were questioned in interviews as to why [redacted], defines this cause as a root cause of the incident.

8.3. Primary Contributing Causes of the Incident

In addition to the direct and root causes, IFO also conducted a thorough investigation that evaluated the Primary Contributing Causes of the Incident on June 8, 2022. In several instances, IFO also ruled out a number of Potential Contributing Causes, which are listed in Section 8.4 below.

8.3.1. The 2016 HAZOP Did Not Evaluate [redacted] and Related Operating Modes

The HAZOP Study documented in *LQF LNG Storage Tank 18T-3 HAZOP Report* dated July 22, 2016 failed to evaluate the impact of operating modes and potential consequences caused by the intentional or accidental [redacted] by operators and the resulting over pressurization of Line [redacted] caused by LNG heating and vaporization. As a result, the HAZOP Study did not identify any current or potential safeguards against the consequences of this scenario and their likelihood of success or failure in preventing the over pressurization of this line.

[redacted]

hazards of this engineering change and determine if sufficient process safeguards were in place.

8.3.2. The Facility Did Not Follow the FLNG MOC Process for Modifications to Unit 18 Tank Management Procedures

FLNG does have a written Management of Change Policy *FLNG-OPS-POL-9001-006.001* with Rev 0 dated 6/23/2021 and intended to comply with 29 CFR 1910.119 (I) with the stated intent of covering all area operations to include [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

IFO reviewed the list of MOCs provided by the Facility for those MOCs performed since 2020. There were no MOCs related to the changes in the operating procedures between the JV and FLNG for the valve settings for the different modes of operation. The completion of a compliant MOC would have provided another opportunity for the Facility personnel to identify operational conflicts and risks within the Regas Operating Procedure(s) [redacted].

8.3.3. Facility Personnel Failed to Recognize an Abnormal Operating Condition and Related Hazards

On the morning of June 6, 2022, an FLNG operator noticed that [redacted] had noticeably moved. He reported this to his supervisor who in turn notified FLNG Operations and Engineering personnel. The mechanical engineer sent out to the unit by his supervisor to evaluate the pipe movement misdiagnosed the issue as a failed spring can attached at the bottom of the line on the side of Tank [redacted] and the lack of a pipe support that was indicated in the design drawings. This engineer had very little experience with piping as his expertise was based primarily on rotating equipment such as pumps and compressors. He prepared a detailed report which was distributed amongst the senior FLNG engineering and operations management team at the site on June 7, 2022 but none of these more experienced personnel went out to the tank farm to evaluate the issue for themselves. Regardless, no one at the site recognized the cause of the unusual pipe movement as thermal expansion resulting in increased pipe pressure applying forces to the expansion joints and other components of line [redacted] and events continued unabated until the BLEVE and subsequent LOPC.

8.3.4. Operator Fatigue

Operator fatigue is believed to have served as a contributing cause of this [redacted]. The Facility had a long-standing practice of calling in operators on overtime to provide the staffing for PSV inspections and other related activities. The investigation team reviewed the hours worked by operations staff for the first half of 2022 (H1 2022) and some clear patterns of concern emerged.

The following observations are a summary of the patterns of hours worked by operators at the plant in 2022 in the days and weeks before the Incident:

- 23% of the staff worked between 110% and 119% of their scheduled hours.
- 54% of the staff worked over 120% of their scheduled hours.
- 20% of the staff worked over 130% of their scheduled hours.
- There have been over 900 occurrences identified in H1 2022 in which operators have worked an overtime shift on one of their scheduled days off.

[redacted] on April 26, 2022 was a “B” Operator who was called in to work overtime on his scheduled day off. [redacted] These pay periods coincided with an operations outage that incurred a significant amount of overtime by operators at the Facility and also encompasses the date when [redacted] was tested.

During the period assessed, each shift averaged 12+ hours per shift and operators generally worked 84 hours per pay period excluding unscheduled overtime.

Fatigue can increase errors, delay responses, and cloud decision-making (*Rogers et al., 1999; HSE, 2005*). Research also shows that complex task decision-making that requires innovative, flexible thinking and planning are highly sensitive to fatigue (*Rogers et al., 1999; Rosekind, et al., 1996 (Appendix M), CSB Texas City Refinery Explosion and Fire – Investigation Report)*.

IFO used a methodology described by the National Transportation Safety Board (NTSB) the NASA Fatigue Countermeasures Program to assess operator fatigue in accidents in conjunction with the other facts and concluded that fatigue was a probable contributing factor in the cause of this Incident.

[redacted]

8.4. Potential Causes Evaluated and Ruled Out

IFO evaluated a number of other Potential Causes of the Incident and ruled them out after careful consideration.

8.4.1. External Hacking and Cyber Attack

IFO interviewed the operator who admitted to [redacted]. Another interviewed operator admitted to [redacted]. The manual inlet isolation valve on [redacted] was [redacted] due to human error. There was no electronic hacking or attack to cause this event. FLNG also conducted an internal review to verify the integrity of the facility's electronic systems and search for any signs of external intrusion which yielded no evidence of external hacking or cyber attack.

8.4.2. External Actor / Malicious Act / Internal Sabotage

For external actor, see above; there were no credible external actors identified during the investigation. Persons involved in the Incident were all FLNG employees. IFO interviewed the operators who conducted these actions and, in our opinion, none of these employees are suspected of intentionally and deliberately engaging in malicious acts related to this incident.

8.4.3. Dropped Object or Mechanical Impact to Piping

There were no witnesses to any such event and no physical evidence present on the scene of the Incident to suggest that a dropped object or mechanical impact directly or indirectly caused this incident. The process data and forensic engineering conclusions clearly indicate that [redacted] caused the LOPC.

8.4.4. Weather or other Natural Causes

There were no adverse atmospheric disturbances based on comments from multiple witnesses and our review of meteorological observations and records from the day of the Incident.

8.4.5. Operator Training

IFO summarized in a table the records of all operator's training. Operator training deficiency was considered to be an area at FLNG needing significant improvement but, not a contributing cause of the accident due to the fact that there are very few procedures used for training and records of training show no consistency for the various classes of operators.

9. CONCLUSIONS AND RECOMMENDATIONS

9.1. Direct Cause of the Incident

IFO determined the direct cause of the June 8, 2022 incident to be [redacted] This [redacted] believed to have occurred during the annual testing of that PSV on April 26, 2022. The [redacted] This factor, in combination with Line [redacted] on June 4, 2022 while partially filled with liquid LNG by [redacted]

[redacted] created the potential for over pressurization of Line [redacted]. [redacted], with no protection from overpressure, was heated by the surrounding environment, causing a pressure of [redacted] to develop, resulting in a BLEVE and bursting of the line.

Immediately following the LOPC, IFO identified the cause of the explosion and fire to be contact between flammable vapor (methane) and an ignition source (open and damaged electrical conduits and circuitry) in the pipe rack following the LOPC, which resulted in a vapor cloud explosion and a small secondary pool fire on the northeast end of the pipe rack in the elevated LNG drainage trench.

There was also a short-term release of vaporizing LNG from damaged 3" piping located on the Tank [redacted] that failed to ignite and was suppressed by firewater master streams deployed by the emergency responders.

9.2. Root Causes of the Incident with Recommendations

9.2.1. Lack of a PSV Testing Procedure and Lack of a Car Seal Program

Cause: FLNG lacked a formal PSV testing written procedure to ensure that PSVs are properly returned to service after testing with isolation valves car-sealed in their correct open positions. In addition, there was no formal car seal procedure, no formal car seal training, no car seal checklist/inventory process, and no formal requirement to audit car seals in use throughout the units.

Recommendation: Develop a PSV Testing Procedure to include also the use of car seals. Consider providing formal classroom and field training using the procedures. Consider developing a Car Seal Program to include 1) procedures for their use, 2) a checklist to be maintained evergreen showing the status of all car seals, 3) formal classroom and field training using the procedures and checklist and 4) internal audits of all plant car seals on an agreed upon schedule.

9.2.2. Lack of Safeguards to Warn Operators of Increasing VIP Pipe Temperature

Cause: Line [redacted]

[redacted] The “leak detection” temperature points offered no safeguard even if alarmed.

Recommendations: Consider performing an alarm rationalization on the VIP pipe systems to identify where audible alarms can be set to warn of high temperature on the inner pipe skin. Analyze temperature data and perform repairs and regular preventative maintenance on temperature indicators to maintain effectiveness of outer pipe skin "leak detection" temperature measurements.

Consider revising the operating philosophy to minimize warming of VIP lines due to loss of flow.

9.2.3. Lack of Operational Integrity of the Operating Procedures that allowed [redacted]

Cause: Section 4.7 includes a detailed discussion of the history of revisions to the FLNG Operating Procedures. [redacted] More than one Control “A” Board Operator said they were not familiar with or had never seen this document. [redacted] This Mode Table sheet, kept in a drawer at the control board was routinely in use to set valve positions for the various modes. As detailed in Section 4.7 it is possible, due to “Operator Choice” designations on [redacted]. Several Control “A” Operators ([redacted]) were questioned in interviews as to why [redacted] (the mode they were in during the incident) and [redacted]. Considering that [redacted] containing LNG is taking a huge risk when considering there is only one safeguard (the PSV), defines this cause as a root cause of the incident. (During the investigation IFO recommended that the “Operator Choice” valves be temporarily changed to “Supervisory Control” until a recommended solution can be agreed on at FLNG.)

Recommendation: Consider a complete review of the operating procedures for the tank farm area. This would include eliminating the hazard of [redacted] containing LNG, Remove the designation “operator choice” valves.

9.3. Contributing Causes of the Incident with Recommendations

9.3.1. 2016 HAZOP Did Not Evaluate [redacted]S and Related Operating Modes

Cause: The HAZOP Study documented in *LQF LNG Storage Tank 18T-3 HAZOP Report* dated July 22, 2016 failed to evaluate the impact of operating modes and potential consequences caused by the intentional or accidental [redacted] by operators and the resulting over pressurization of Line [redacted] caused by LNG heating and vaporization. As a result, the HAZOP Study did not identify any current or potential safeguards against the consequences of this scenario and their likelihood of success or failure in preventing the over pressurization of this line. A design change was made after the HAZOP that resulted in Line [redacted] designed as a VIP line. There is no record that an MOC was signed off or PHA was reconvened to consider this change.

Recommendation: Consider performing a revalidation PHA for all VIP piping systems to ensure the necessary safeguards are provided in the design based upon the severity of consequence, including, in particular, identifying and avoiding or mitigating scenarios of [redacted].

9.3.2. The Facility did not follow the FLNG MOC process for modifications to Procedure-Unit 18 Tank Management.

Cause: FLNG does have a written Management of Change Policy *FLNG-OPS-POL-9001-006.001* with Rev 0 dated 6/23/2021 and intended to comply with 29 CFR 1910.119 (l) [redacted]

[redacted]

[redacted]

IFO reviewed the list of MOCs provided by the Facility for those MOCs performed since 2020. There were no MOCs related to the changes in the operating procedures between the JV and FLNG for the valve settings for the different modes of operation. The completion of a compliant MOC would have provided another opportunity for the Facility personnel to identify operational conflicts and risks within the Regas Operating Procedure(s) and prevent the intentional or inadvertent [redacted] containing LNG.

Recommendation: Consider using FLNG's existing MOC process and procedure for all changes to the unit as defined in the procedure.

9.3.3. Facility Personnel Failed to Recognize an Abnormal Operating Condition and Related Hazard

Cause: On the morning of June 6, 2022, an FLNG operator noticed that [redacted] had noticeably moved. He reported this to his supervisor who in turn notified FLNG Operations and Engineering personnel. The mechanical engineer sent out to the unit by his supervisor to evaluate the pipe movement reported the issue as a possible failed spring can attached at the bottom of the line on the side of Tank [redacted] and the lack of a pipe support that was indicated in the design drawings. This engineer had very little experience with piping as his expertise was based primarily on rotating equipment such as pumps and compressors. He prepared a detailed report which was distributed amongst the senior FLNG engineering and operations management team at the site on June 7, 2022 but none of these more experienced personnel went out to the tank farm to evaluate the issue for themselves. Regardless, no one at the site recognized the cause of the unusual pipe movement as thermal expansion resulting in increased pipe pressure applying forces to the expansion joints and other components of line [redacted] and events continued unabated until the BLEVE and subsequent LOPC.

Recommendation: Engineering, operations and maintenance personnel should be trained to recognize Abnormal Operating Conditions (AOCs), including those related to pipe movement and the recognition of pipe movements/stresses as a result of [redacted]

9.3.4. Operator Fatigue

Cause: Operator fatigue is believed to have served as a contributing cause of this incident due to the probable failure of the assigned FLNG operator to [redacted] after it was tested by the [redacted] technician on April 26, 2022. The Facility had a long-standing practice of calling in operators on overtime to provide the staffing for PSV inspections and other related activities. The investigation team reviewed hours worked by operations staff for the first half of 2022 (H1 2022) and some clear patterns of concern emerged.

[redacted]

Operator fatigue was studied with respect to number of hours worked and summarized in Section 8.3.8. Operators and supervisors made numerous comments in interviews during the investigation about operators feeling fatigued due to the number of hours worked and erratic scheduling.

Recommendation: Consider a review of operator staffing and hours worked.

10. REFERENCES AND CITED DOCUMENTS

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ASTM E 1459, *Standard Guide for Physical Evidence Labeling and Related Documentation* (1998).

Balzhiser, Samuels and Eliassen *"Chemical Engineering Thermodynamics",* p. 106 and 146. (1972).

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National Fire Protection Association (NFPA) Standard 921*, Guide for Fire and Explosion Investigations.*

Price, Jana, 2005*. "A Review of the Evidence Investigators use in Determining Operator Fatigue," published in the Proceedings of the 2005 International Conference on Fatigue Management in Transportation Operations, Seattle, WA: September 11-15.*

Rosekind, M., Gander, P., et al., 1996*. "Managing Fatigue in Operational Settings I: Physiological Considerations and Countermeasures," Behavioral Medicine, Vol. 21, 157-165.*

Rosekind, M., Gregory, K., et al., 1993*. "Analysis of crew fatigue factors in AIA Guantanamo Bay aviation accident, Appendix E," to Aircraft Accident Report: Uncontrolled Collision with Terrain, NTSB/AAR-94/04, Washington, D.C.: NTSB.*

Rogers, A.S., Spencer, M.B., and Stone, B.M., 1999*. Report 245/Validation and Development of a Method for Assessing the Risks Arising From Mental fatigue, prepared by the Defence Evaluation and Research Agency Center for Human Services, for the HSE, U.K.*

11. ACRONYMS

BOG (Boil Off Gas) - LNG vaporized due to warming above liquefaction temperature is referred to as boil off gas.

BLEVE (Boiling Liquid Expanding Vapor Explosion) - is an explosion caused by the rupture of a vessel containing a pressurized liquid that has reached temperature above its boiling point. If the pressurized vessel ruptures, the pressure which prevented the liquid from fulling boiling is lost. If the rupture is catastrophic, where the vessel is immediately incapable of holding any pressure at all, then there suddenly exists a large mass of liquid which is at higher temperature and very low pressure. This causes a portion of the liquid to "instantaneously" boil, which in turn causes an extremely rapid expansion. Depending on temperatures, pressures and the substance involved, that expansion may be so rapid that it can be classified as an explosion, fully capable of inflicting severe damage on its surroundings.

FLNG - Freeport Development LNG LP – majority owner of the Facility.

HV Valve - An HV valve is typically a hand operated manual on/off or throttling valve although they can be equipped with actuators for process control or emergency closure.

LOPC – Loss of Primary Containment – CCPS (Center for Chemical Process Safety) defines LOPC as an unplanned or uncontrolled release of material from primary containment.

Master Stream - Master streams are an effective tool used to fight and suppress fires, especially in defensive situations or when distance must be maintained while flowing large volumes of water. Master streams, like those mounted on a truck or ground mounted, are capable of delivering water anywhere from 500 to 2,500 gallons per minute at more than 100 psi.

MAWP – Maximum Allowable Working Pressure is an American Society of Mechanical Engineers (ASME) designation that establishes the rating for pressure-relief components on vessels. It measures the greatest amount of pressure that the weakest part of the vessel can handle at specific operating temperatures.

PSI – Process Safety Information

XV Valve - An XV valve is an on/off valve mainly used to provide tight closing conditions (TSO). They can be operated remotely with the use of actuators or manually.

VIP - Vacuum Insulated Piping forms the basis of almost every cryogenic infrastructure. The double-walled pipes ensure that cryogenic gases can be safely transported without excessive warming and loss of their liquid state.

12. APPENDICES

[redacted]

[redacted]

[redacted]

12.2. Plan Location of Temperature Cool Down and Leak Detection

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

12.3. Pipe Equivalent Length, Hydraulic, and Volume Calculations – Excel and Hysys 12.1

[redacted]

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

[redacted]

Sun Sep 4 01:13:46 2022 [redacted] Flowsheet: Case (Main)

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

[redacted]

[redacted]

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

[redacted]

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

[redacted]

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[redacted]

[redacted]

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

[redacted]

[redacted]

CONFIDENTIAL BUSINESS INFORMATION—DO NOT RELEASE UNDER FOIA

[redacted]

12.4. Redlined P&IDs Showing Major Damage

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

12.5. Plot Plans with Gas Detection and Fire Detection First Outs

[redacted]

[redacted]

[redacted]

[redacted]

12.6. System and Burst Pressure Calculations

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

12.7. Equipment Damage Assessments

Visual Damage Assessment Piping Rack and Mezzanines for LNG Tanks 1,2, and 3

Freeport LNG
Quintana Island, TX

Prepared for:

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June 28, 2022

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LIST OF FIGURES

[redacted]

[redacted]

CONFIDENTIALITY AND DISCLAIMER

EXECUTIVE SUMMARY

A visual assessment was conducted at the Freeport LNG operation in Quintana, Texas of the Valves and Piping for the [redacted]. The visual assessment has been conducted to evaluate visible damage as the result of a loss of primary containment of an [redacted] between LNG [redacted] The visual assessment is intended to identify visually damaged or potentially damaged piping and valves in the primary pressure release and fire-impacted area.

VISUAL ASSESSMENT OF VALVES AND PIPING

The visual assessment was conducted by IFO personnel, with the support of FLNG operational staff. The FLNG operational staff assisted in the identification/verification of assets (Piping and Valves) and the prior condition and placement of the assets. The visual assessment is not intended to replace a detailed and comprehensive inspection including the use of various NDT methods to determine the current condition of the assets and their Fitness for Service. The visual assessment is intended to identify assets that may have been impaired related to their ability to function properly and perform as designed. The assessment included a screening for mechanical distortion, structural damage, damage to pipe coating and insulation, equipment, utilities, and instrumentation wherever possible given the limited access to some elevated areas of the pipe rack.

CODES AND STANDARDS

- *API 570 Pressure Piping Inspection*
- *ANSI/ASME B31.3 Piping Code*
- *49 CFR Part 193*
- *ANSI/API 574*
  Inspection Practices for Piping System Components.
- *ANSI/API 576*
  Inspection of Pressure Relieving Devices.
- API 598
  Valve Inspection and Testing.
- *API SPEC 6D*

SUMMARY OF PIPE RACK DAMAGE ASSESSMENT

As the damage was widespread throughout the Pipe Rack, IFO utilized the following elements to list the type of visible damage observed to the [redacted]

1) Severe Damage – The piping has been severely damaged and/or is missing from this area in the pipe rack.
2) Dent(s) – The piping has a dent or several dents greater than 1"
3) Gouge(s) – The piping has a gouge or several gouges
4) Pipe Support -The pipe support has been damaged
5) Instrumentation – Visible instrumentation damage observed
6) Concrete – Concrete damage observed
7) Flame – Direct flame or fire damage observed
8) Moved – The pipe has moved from its original position, or has exhibited movement at the time of the event/pressure release

Note Related to Pipe Movement: When a VIP line has moved as a result of an external force the condition of the inner LNG line cannot be visually determined**.** Additional assessments utilizing advanced inspection methods must be utilized as applicable. A hydrostatic test will only verify the leak tightness of the piping at the moment of the hydrostatic test at ambient temperatures. A hydrostatic test can not verify the stresses the pipe may have been subjected to, and it cannot detect potential damage that the line may have incurred at the time of the event, such as non-through wall cracking.

The same applies to all non-VIP lines but additional inspection methods may be utilized to determine the full current condition of the pipe and its welds, beyond leak tightness via a hydrostatic test. Use of alternative inspection methods should be considered to verify integrity of piping.

"Typical" damage was documented with photography and attached to specific sections as applicable. Specific notable damage in some sections was also documented and attached to the applicable pipe rack section summary below each table.

The Pipe Rack positions are based on the Pipe Rack Structural Steel Isometric Drawings provided to IFO by FLNG.

AREA OF DAMAGE ASSESSMENT – AERIAL VIEW

[redacted]

[redacted]

Figure 2 - Pipe Rack in Front of Tank [redacted]

[redacted]

[redacted]

Figure 4 - Pipe Rack West Side and Mezzanine [redacted]

[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted] Piping Movement

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

SUMMARY OF MEZANNINES AND LOOP 2 DAMAGE ASSESSMENT

[redacted] was impacted by the failure of the [redacted]e and its ejection through the East side and East end of the pipe rack. As most of the equipment and lines in the [redacted] area are insulated, a detailed assessment was limited by the insulation and limited ingress and egress. Removal of the insulation will be required to assess the extent of damage that has occurred to the piping, valves, and associated equipment & instrumentation impacted in this area. In the below table are the current observations and assessments that have been completed.

[redacted]

[redacted]

SUMMARY OF MEZZANINE 3 DAMAGE ASSESSMENT & TANK [redacted] FILL LINE

Mezzanine 3 was impacted by the [redacted] line failing and being projected through the West side of the pipe rack, impacting multiple process lines. There is extensive damage to piping, valves, process equipment, and instrumentation in the Mezzanine area. The damage and movement of several of the piping lines and equipment have limited access to fully assess the extent of all the damage. As the damaged assets are removed and the area is safely secured additional assessments and inspections will be required.

As most of the equipment and lines in the Mezzanine 3 area are insulated, a detailed assessment was limited by the insulation and limited egress due to the magnitude of damage. Having all the insulation removed will be required to assess the extent of damage that has occurred to the piping, valves, associated equipment & instrumentation impacted in this area. In the below table are the current observations and assessments that have been completed.

[redacted]

[redacted]

[redacted]

OBSERVATION OF TANK [redacted] FILL LINES

A [redacted] has been damaged by a large section of the [redacted] near [redacted] (see picture below). The insulation has been torn away and the pipe has experienced a direct impact. A detailed inspection will be required to determine the extent of the damage. One of the [redacted] has moved off its vertical supports at multiple locations. The [redacted] visually appears to have moved off its horizontal pipe support at the top of the tank. This area was visually evaluated using a drone and there is evidence of the pipeline making direct contact with the pipe support. The insulation is damaged and the [redacted] is no longer plump and off its vertical alignment (it is leaning away from the tank visually). This entire line needs to be evaluated for damage from the Mezzanine [redacted] area to the top and inlet line on Tank [redacted] for damage and stress loading.

[redacted]

[redacted]

[redacted]

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Safety, Risk & Fire Consultants

Freeport LNG
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Structural Assessment Report

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August 23, 2022

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1.0 STRUCTURAL

Beginning on June 11, 2022, IFO forensic structural engineers were on the scene to observe and document the damage and assist with the cause and origin determination of the Incident. Also, the two buildings in the vicinity of the Incident, the re-gas control room, and the old maintenance building were evaluated for potential damage from the BLEVE overpressure. An evaluation of the damage to the pipe rack structure, as well as the adjacent process platforms was also completed.

1.1 Regas Control Room and Old Maintenance Building

Re-Gas Control Building:

Inspection of the two buildings was performed on June 12, 2022. [redacted] The inspection was limited to a visual observation of the exterior and exposed structural components above the ceilings to note any abnormality or unusual movement in the structural components. The roofs on both structures were inspected by a drone.

[redacted] The building did not appear to show any sign of typical movement due to overpressure and/or impact from large air-borne debris. Interior inspection did not show any sign of movement. No debris or impacts on the roof of the building were observed, and no damage was observed to the doors and/or glazing to the North side of the building.

[redacted]

[redacted]

Based on the observations, it is our opinion that the building did not suffer damages due to the incident on June 8, 2022 and is structurally safe.

It is imperative to review the blast rating due to conditions of the doors and windows. At the same time the building pressurization should be reviewed to confirm that the space can be used as safe heaven.

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Re-Gas Maintenance Building

[redacted]

Our inspection showed some minor movements in the secondary structural framing. A picture frame had been dislodged from the wall in [redacted]. Also found an exit sign cover that had been dislodged in the shop area near [redacted] The exit sign was mounted to the girts above.

No debris or impact marks were found on the roof of the building. No damage to glazing, doors, or overhead doors was identified. Therefore, it is our opinion that the structural systems were not damaged during the incident.

[redacted]

[redacted]

1.2 Pipe Rack

Introduction

[redacted]

[redacted]

1.3 Structural Damage Observations

Several structural members were severely damaged during the incident. Near the point of rupture, between [redacted], the concrete deck at the mid-level breached due to the pressure release.

[redacted]

The reinforcing steel remained mostly intact, but the concrete matrix ruptured from the top surface. This failure mode is consistent with localized, high intensity pressure with a short phase duration.

On the mid-level in this same vicinity, several of the precast concrete curbs were dislodged by the lateral movement of the failed pipe. Some of these curbs were displaced to the ground below, but others came to rest on the structural steel beams and bracing on the south side of the pipe rack. An example of this is shown in figures SCA_4135, SCA_4136, SCA_4142).

[redacted]

The impact damages on the mid-level occurred near the point of rupture and indicate that the initial trajectory of the pipe in this area was lateral (to the north).

[redacted]

On the west end near the process platform mezzanine, severe damage to the structural steel columns and beams was observed. [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

There were also damage to minor structural elements on the process mezzanines. The movement in the piping and elbows impacted structural steel pipe supports in several locations on both the east and west process mezzanines.

1.4 Structural Blast Analysis

The damage to the pipe rack structure occurred in several isolated locations. The damage near the epicenter was observed on the mid-level of the pipe rack. The pressure release fractured the concrete deck, and the lateral movement of the failed pipe sections dislodged the precast concrete curb. The damage to the structural steel members occurred further away from the epicenter. The structural steel on the top level was damaged from the impact of the pipe sections.

The damage to the structural members resulted in severe deformations and partially collapsed members at isolated locations. The structure maintained its global stability; however, the damaged sections have diminished gravity and lateral load resisting capacity and may not meet the required load combinations. Therefore, the damaged members and connections should be replaced in their entirety.

It should be noted that all of the observed damage was consistent with a localized pressure release or impact damage. None of the observed damage was caused by overpressure from a deflagration or detonation

1.5 Pipe Rack Damage Detailed Observations

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] b on [redacted]

Pic[redacted]rth

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

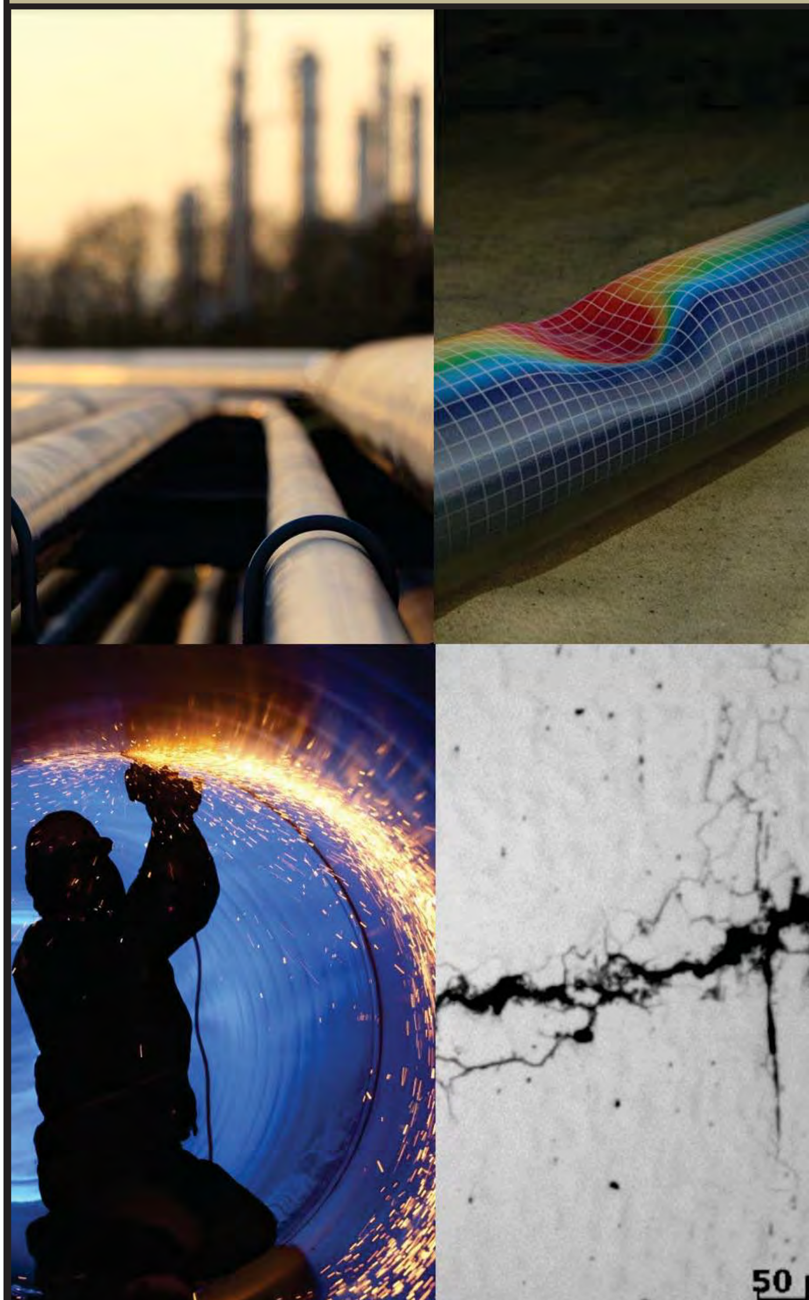
[redacted]

[redacted]

[redacted]

12.8. Metallurgical Examination of Line [redacted] Materials

Metallurgical Examination of Line [redacted] Materials



Report #: IFO0220706-02

Prepared for:
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Conroe, TX 77385

Prepared by:
[redacted]

October 31, 2022

Solving Problems, Around the Clock,
Around the World

EXECUTIVE SUMMARY

IFO Group ("IFO") are the principal investigators of a failure related to line over-pressurization and subsequent fire at Freeport LNG ("FLNG") in Quintana, TX ("facility"). On June 8, 2022 at approximately 11:40 AM CDT, there was a high energy release of product followed by a fire. The release occurred in an approximately [redacted] span of vacuum insulated pipe ("VIP"). KnightHawk Engineering, Inc. ("KHE") was contracted to perform a metallurgical testing on the materials of the [redacted] line involved in the explosion.

Metallurgical testing of the fracture surfaces of some (but not all) of the Line [redacted] bellows found the presence of low cycle fatigue cracking, as demonstrated by: (1) the presence of significant parallel secondary cracks; (2) significant strain hardening; (3) slip band formation with crack initiation; (4) crack tip blunting; (5) fracture surface rubbing; and (6) the presence of fatigue striations. Based on the expected time to fatigue crack initiation under low cycle fatigue conditions, and the distance of propagation of the fatigue crack, KHE estimates that approximately 10% of the fatigue life of the bellows was expended based on the metallurgical data.

Metallurgical analysis of the some of the fracture surfaces of the bellows and all of the fracture surfaces of materials unassociated with the bellows (e.g. pipe base metal, welds, etc.) from line [redacted] showed that the failures were due to overload of the pipe, as is expected given the nature of the overpressure event and subsequent explosion. No additional failure modes were observed.

KHE performed positive material identification ("PMI") on the materials used to construct Line [redacted] and found no deviations in the metallurgical chemistry of the lines. The yield and tensile strengths of the lines were higher than expected for the materials of construction (mainly 304 stainless steel), while the total elongation was generally lower than expected. However, all of these deviations are consistent with the yielding of the line due to the overpressure event it experienced prior to the failure. Thus, KHE does not consider there to be any deviations from expectation with respect to the materials of construction.

KHE analyzed a location where there was a "bulge" on the inner diameter ("I.D.") of the inner pipe. KHE determined that the cause of the bulge was the presence of radial supports between the inner and outer pipe which constrained the expansion of the inner pipe during the slow increase in the inner pipe pressure.

KHE performed a hydrotest on the pressure safety valve ("PSV") associated with Line [redacted]. The valve was found to release pressure between 212 and 215 PSIG, and the set pressure was found to be 225 PSIG. The PSV was not found to leak below 210 PSIG. Analysis of the PSV components revealed wear on the shaft of the spring side mating surface, but KHE does not believe that this wear would be sufficient to compromise the function of the PSV.

Note: KHE reserves the right to modify or change any opinions based on any new data or information obtained and any ongoing work in progress relevant to this project.

Respectfully submitted,

[redacted]
Laboratory Director

Approved,

[redacted]
Senior Metallurgical Consultant
KnightHawk Engineering, Inc.
TX Registration – 143930
TX Firm - 1720

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FIGURES

Tables

1 Introduction

IFO Group ("IFO") is the principal investigator of a failure related to a line over-pressurization and subsequent fire at Freeport LNG ("FLNG") in Quintana, TX ("facility"). On June 8, 2022, at approximately 11:28 AM CDT, there was a high energy release of product followed by a fire. The release occurred in an approximately [redacted] span of vacuum insulated pipe ("VIP").

KnightHawk Engineering, Inc. (KHE) has been contracted to perform metallurgical testing on the [redacted] involved in the explosion, as well as pressure testing of the pressure safety valve ("PSV") associated with Line [redacted]

2 Scope

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[redacted]

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3 ASSUMPTIONS

KHE defined the following assumptions for the work presented in this report:

1. In developing this report, KHE assumes that plant operation and maintenance of subject equipment and interconnecting equipment are in accordance with generally accepted industry standards except

where noted. All related equipment is designed and installed in accordance with applicable codes and standards.

2. All analysis, reviews, and verification are developed based on KHE's experience and methodology for this type of project in industry.
3. In addition to the results of the tests conducted, the validity of this metallurgical assessment also depends upon, and is limited to, the accuracy and completeness of the data provided by IFO to KHE, as applicable.

4 Class 1 – Metallurgical Analysis of Fracture Surfaces

KHE received samples from the [redacted] Line at KnightHawk Materials Lab ("KML") for metallurgical examination and testing, as defined in IFO0220706-02P Final Metallurgical Testing Protocol.

4.1 Photo Documentation

Photos were taken during site visits to both FLNG's plant and the warehouse rented by IFO to store the samples, as well as at KML. The samples considered for the fatigue analysis were IFO-FLNG-0089 (Sample 89) and IFO-FLNG-0104B (Sample 104B) as shown in Figure 1 through Figure 7. The following observations can be made from the visual examination.

[redacted]

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4.2 Stereo Microscopy

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[redacted]

4.3 Compound Optical Microscopy

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4.4 HARDNESS TESTING

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4.5 SEM

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4.6 Discussion

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4.7 Conclusions

Based on the metallurgical analysis conducted, KHE concludes the following:

1. The bellows of the inner pipe suffered from low cycle fatigue loading prior to the failure event, leading to crack initiation on the O.D. of the bellows in the valleys. The fatigue life expended is estimated to be on the order of 10%.
2. The remaining fracture surfaces examined on Line [redacted] materials were all caused by ductile overload.
3. There was no indication of weld or material embrittlement on the fracture surfaces examined.

5 CLASS 2 – POSITIVE MATERIAL IDENTIFICATION AND MECHANICAL INSPECTION

Materials were taken from the remains of Line [redacted] for PMI and mechanical testing (tensile and weld hardness) in order to verify that the materials used in the construction of the line met the requirements of the specified grades.

5.1 OPTICAL EMISSION SPECTROSCOPY

Optical Emission Spectroscopy ("OES") of the samples was conducted at two different, independent laboratories in order to determine whether the materials of construction matched the requirements for the steel grades (namely 304 stainless steel). The results of the OES testing are presented in Table 4. Of the large number of materials and locations tested, no single average element composition falls outside of the requirements for 304L stainless steel. As such, KHE concludes that the materials used in the construction of Line [redacted] were in full compliance with the chemical requirements of the grade.

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5.3 WELD HARDNESS TESTING

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[redacted]

[redacted]

5.4 WELD MICROSTRUCTURES

The microstructures of the welds were examined using stereo and compound optical microscopy. No deviations were found in the weld microstructures. Characteristic microstructures of the inner pipe weld microstructures are shown in Figure 69 through Figure 74, characteristic microstructures of the outer pipe transverse welds are shown in Figure 75 through Figure 79, and characteristic microstructures of the outer pipe longitudinal welds are shown in Figure 80 through Figure 84. There were no notable deviations from the expected microstructures for welds in austenitic stainless steel noted on any of the samples tested by KHE.

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[redacted]

5.5 Discussion

The materials of construction of Line [redacted] at FLNG appear to have been within the expected specifications of the material. There are no indications to suggest that the materials of construction or integrity of the welds played any role in the failure of the line.

6 Class 3 – Inner Pipe Bulge Analysis

There were locations noted on the inner pipe of Line [redacted] that appeared to have bulged inwards. These locations were concentrated around the circumferential supports that kept the inner pipe of the line centered within the outer pipe. Analysis was performed on one of these sections in order to explain the cause of the bulging, and to determine if it had an impact on the failure of the line.

6.1 Optical Examination

A section of the inner pipe that bulged around a support is shown in its as-received condition in Figure 85, with a cross section of the bulge shown in Figure 86. The following observations can be made from the optical examination.

- The radial support pipe has collapsed more completely on one side than on the other (Figure 85 and Figure 86).
- The bulge of the inner pipe is most severe where the collapse of the radial support pipe is at a minimum (Figure 86).

[redacted]

[redacted]

6.2 Hardness Testing

Hardness testing was performed using a Vickers macro hardness tester and a 10 kg load. Hardness testing was conducted at locations as shown in Figure 87, with the hardness results shown in Table 11. The hardness of the inner pipe in this location is generally within the range expected of 304L pipe, with higher hardness immediately below the center of the bulge. This pattern is expected due to the combination of increased deformation, and thus strain hardening, at that location, and the presence of a weld in the vicinity.

[redacted]

6.3 COMPOUND OPTICAL MICROSCOPY

Cross sections of the center of the bulge and of material away from the bulge were taken and polished to a metallographic (mirror) finish for examination using a compound optical microscope (shown in Figure 88 through Figure 90). The microstructure is as expected for an austenitic stainless steel alloy, and does not show significant differences between the bulged and non-bulged sections.

[redacted]

[redacted]

[redacted]

6.4 Discussion

The bulges of the inner pipe of Line [redacted] are the result of the radial expansion of the line due to the pressure event, and the constraint of that radial expansion caused by the radial pipe supports. The internal pressure of the line during the event caused the radius of the inner pipe to increase through yielding and plastic deformation of the line. However, in the immediate vicinity of the radial supports, this expansion was constrained. Since the radial expansion of the inner pipe occurred over a relatively long period of time, and the pressure was roughly isotropic, the expansion of the line was also approximately isotropic, which resulted in the appearance that the locations where the expansion of the line was constrained had "bulged inward," where in reality those locations had stayed relatively stationary while the material around those locations expanded outwards. This is clearly demonstrated by the fact that the apparent bulge is most severe in the location where the radial support pipe collapsed the least. Thus, the "bulges" of the inner pipe are deemed secondary consequential damage of the primary failure and did not contribute to the failure of Line [redacted]

7 Class 4 – PSV Pressure Test and Teardown

KHE performed a hydrotest on the Line [redacted] pressure safety valve (PSV), and subsequently performed a teardown and examination of the parts of the PSV.

7.1 Hydrotesting

KHE performed hydrotesting of the PSV. [redacted]

[redacted]

[redacted]

7.2 PSV TEARDOWN

[redacted]

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7.3 DISCUSSION

There is no significant wear to the PSV mating surfaces. This, combined with the satisfactory hydrotest performance, indicates that the PSV was fully operational at the time of the incident, although it was [redacted] The only wear of note on any of the PSV components occurred on the shaft of the PSV spring side mating surface. While it is possible that this wear could be caused by over activation of the PSV, the wear appears more consistent with heavy localized rubbing damage. The observed wear on the shaft is unlikely to have had any impact on the operation of the PSV.