BSEE Panel Report 2023-001

Investigation of July 25, 2020, Flowline Jumper Failure

Lease OCS-G34536

Green Canyon Area Block 40

Gulf of Mexico Region

Houma District

Feb. 15, 2023

The BSEE's National Investigations Program is administered by its Safety and Incident Investigations Division in Sterling, VA. Panel investigations, an integral tool for safety improvement, are chaired by division and regional staff, and conducted in coordination with regional and district staff.

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Abbreviations and Acronyms

Abbreviation/Acronym	Description
API	American Petroleum Institute
ASD	Acoustic Sand Detector
ASTM	American Society for Testing and Materials
BOD	Basis of design
BOM	Bill of materials
BSDV	Boarding Shutdown Valve
BSEE	Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
CI	Corrosion Inhibitor
CP	Cathodic Protection
CRO	Control Room Operator
CVC	Collet Vertical Connector
CVN	Charpy V-Notch (impact test)
DOI	Department of the Interior
DWOP	Deepwater Operations Plan
EDS	Energy Dispersive X-Ray Spectroscopy
EPCI	Engineering, Procurement, Construction & Installation
FAT	Factory Acceptance Test
Fieldwood	Fieldwood Energy
FLIV	Flowline Isolation Valve
ft	Feet
GC	Green Canyon
GC Block 39	Green Canyon Block 39
GC Block 40	Green Canyon Block 40
GOM	Gulf of Mexico
GOMR	Gulf of Mexico Region
HD	Houma District
HE	Hydrogen Embrittlement
HISC	Hydrogen Induced Stress Cracking
Host Facility	Tarantula Production Platform (located in South Timbalier Area Block 308)
HRC	Rockwell Hardness Scale C
ILS	In-Line Sled
IIT	Incident Investigation Team
IMT	Incident Management Team
Inconel 718	Nickel Based Alloy 718 (Alloy UNS N07718)

JSA	Job Safety Analysis
K1 Jumper	K1 Well Jumper (Pipeline Segment Number 20199)
K1 PLET	K1 Well Pipeline End Termination
K1 Tree	K1 Well's Subsea Production Tree (located in GC Block 40)
K1 Well	Katmai Field Subsea Well #1
K2 ILS	K2 Well In-Line Sled
K2 Jumper	K2 Well Jumper
K2 Tree	K2 Subsea Well Production Tree (located in GC Block 39)
K2 Well	Katmai Field Subsea Well #2
ksi	1,000 pounds per square inch
Lease	OCS-G 34536 Lease
LiDAR	Light Detection and Ranging
LSH	Level Safety High
MAOP	Maximum Allowable Operating Pressure
MAWP	Maximum Allowable Working Pressure
MEG	Monoethylene Glycol
MOC	Management of Change
MPFM	Multiphase Flowmeter
MRDB	Manufacturing Record Data Book
MTR	Material Test Report
NOAA	National Oceanic and Atmospheric Administration
Noble	Noble Energy, Inc.
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OD	Outer Diameter
OEM	Original Equipment Manufacturer
OJT	On-the-Job Training
OSV	Offshore Supply Vessel
P/N	Part Number
PBU	Pressure Build-up Test
PCV	Production Control Valve (K1 Subsea Choke Valve)
PIP	Pipe-in-Pipe
PLET	Pipeline End Termination
PM	Preventive Maintenance
PMV	Production Master Valve
PSH	Pressure Safety High
psi	Pounds Per Square Inch
PSIG	Pounds Per Square Inch Gauge
PSN	Pipeline Segment Number

PT	Penetrant Test (Dye Penetrant Examination)
PTW	Permit to Work
PWV	Production Wing Valve
QA	Quality Assurance
QC	Quality Control
ROV	Remotely Operated Vehicle
SAB	NOAA Satellite Analysis Branch
SCSSV	Surface-controlled Subsurface Safety Valve
SEM	Scanning Electron Microscope (Microscopy)
SEMS	Safety and Environmental Management Systems
SES	Stress Engineering Services, Inc.
SIA	Subsea Integrated Alliance
SITP	Shut-in Tubing Pressure
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
SOP	Standard Operating Procedure
SS7	Subsea 7
SSLD	Subsea Leak Detection
ST	South Timbalier
SURF	Subsea, Umbilical, Riser, and Flowline
UR	Utilization Ratio
USCG	United States Coast Guard
YS	Yield Strength

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Executive Summary

The Bureau of Safety and Environmental Enforcement (BSEE) convened a panel to investigate a July 25, 2020, release of approximately 479 barrels of oil into the Gulf of Mexico (GOM) when a failure occurred at a flanged connection on the Katmai Field Well #1 (K1 Well) Subsea Jumper (K1 Jumper, Pipeline Segment No. (PSN) 20199). Operated by Fieldwood Energy, LLC (Fieldwood), the K1 Jumper is located approximately 140 miles south of New Orleans, Louisiana, in Green Canyon Area (GC), Block 40, in approximately 2,082 feet (ft) of water. The K1 Jumper is approximately 26 miles from the Tarantula Platform (Host Facility) in South Timbalier Area (ST), Block 308, and is connected to the Host Facility by the Katmai Flowline.

BSEE's investigation found that the failure occurred on the K1 Jumper at a 90-degree connection where the Multi-Phase Flow Meter (MPFM) bottom 4-inch flange met up with the 4-inch studded block (Blind Tee). The post-incident evaluation revealed the failure occurred due to the fracture of four of the eight flange fastener studs. The four failed studs fractured at the first thread engagement of the nut and were adjacent to one another on the same side of the flange. At the time of the incident, the K1 Jumper had been in service less than 40 days, the K1 Well was the only input source into the Katmai Flowline, the K1 Well was shut-in, and the K1 Jumper's internal pressure of 7,252 psi was below the maximum allowable design pressure.

On March 22, 2020, after subsea installation, the K1 Jumper successfully passed the required pressure test by holding 15,000 pounds-per-square-inch (psi) internal pressure for two hours.

On June 18, 2020, the K1 Well started producing oil. Between initial production and July 25, 2020, the K1 Well production was shut in six times due primarily to issues encountered on the Host Facility.

On July 25, 2020, at 5:24 p.m. with the well shut-in, an abnormal internal pressure drop occurred in the Katmai Flowline from approximately 7,252 psi to 5,037 psi within one hour. After identifying this pressure drop, personnel on the Host Facility evaluated topsides process equipment, incoming flowlines, and valves for potential leak paths. However, the crew could not find a source on the Host Facility to explain the change in pressure.

Onshore and offshore personnel evaluated the possible causes for the pressure drop. A decision was made to keep the well shut-in and perform a visual sheen inspection at the GC 40 location. Due to weather and lack of daylight, neither a vessel nor a helicopter could be dispatched that night.

On July 26, 2020, Control Room Operators (CRO) monitored the Katmai Flowline pressures which were above the mudline hydrostatic seawater pressure and were decreasing at a lesser rate than the previous evening. Fieldwood was unable to mobilize a flight due to weather, but a vessel was dispatched to observe the water surface above the Katmai Flowline and K1 Well locations. When the vessel arrived, personnel observed a rainbow-colored sheen on the surface near the K1 Well, prompting personnel on the Host Facility to depressurize the Katmai Flowline. At 3:04 p.m., Fieldwood reported the incident to the BSEE Houma District.

On July 27, 2020, Fieldwood dispatched a remotely operated vehicle (ROV) to survey the Katmai Flowline near the K1 Tree. The ROV survey revealed breaches in the insulation surrounding the flange connection of the MPFM and Blind Tee on the K1 Jumper.

The BSEE Panel identified the following probable cause(s) and contributing cause(s) that led to the pollution event. The Panel also developed the following recommendations for improvement of the existing safety and environmental management systems.

Probable Causes:

- Failure to install American Petroleum Institute (API) 6ACRA-compliant studs in the K1 Jumper MPFM flange connection.
- Engineering documentation used for procurement did not specify API 6ACRA compliance for subsea flange fasteners (studs and nuts).
- Gap in the Quality Assurance/Quality Control (QA/QC) process allowed for non-API 6ACRA-compliant subsea flange fastener installation.

Contributing Causes:

- Management of Change (MOC) process was not followed.

Recommendations for lessees and operators to consider for improved implementation of existing safety and environmental management systems:

- Utilize an industry-knowledgeable metallurgist to evaluate all current and future subsea fasteners to verify fasteners are fit for service and not prone to Hydrogen Embrittlement (HE) or any other environmental cracking failures. For future installations, ensure the metallurgical evaluation is performed during the engineering technical review phase before releasing the engineering design for construction.
- Share Subsea Leak Detection (SSLD) system learnings with industry.
- Emphasize that company, contract, and sub-contract personnel enact MOC when there are modifications associated with equipment, operating procedures, personnel changes, materials, and operating conditions.
- Validate and document flange fastener make-up torque values.
- Ensure SSLD notification system alarms are appropriately set with effective alerts and properly monitored during shut-in, transient, and steady state production operating conditions.
- Consider the subsea leak potential while investigating significant subsea flowline pressure drops even when the pressure trends are above the ambient pressure of the sea.

The Panel also encourages industry to develop a standard means for determining shear and torsional capacities of API flange connections.

Introduction

Authority

Pursuant to 43 U.S.C. § 1348(d)(1) [Outer Continental Shelf Lands Act (OCSLA), as amended] and Department of the Interior regulations at 30 CFR part 250, the Bureau of Safety and Environmental Enforcement (BSEE) is required to investigate and prepare a public report for this incident. BSEE has authority pursuant to 43 U.S.C. § 1348(f) to summon witnesses and require the production of documents while conducting an investigation pursuant to 43 U.S.C. § 1348(d)(1)-(2). Accordingly, BSEE convened a Panel Investigation Team that included:

- Nicholas Fraiche[1], Petroleum Engineer, Office of Incident Investigations, GOM OCS Region
- Ashton Blazquez, Petroleum Engineer, Production Operations Inspection Unit, New Orleans District, GOM OCS Region
- Kuo-Shian Kao, Petroleum Engineer, Technical Assessment Section, Regional Field Operations, GOM OCS Region
- Ross Laidig, Special Investigator, Safety and Incident Investigations Division, Headquarters
- Bimal Shrestha, Petroleum Engineer, Pipeline Section, Regional Field Operations, GOM OCS Region

Pursuant to 30 C.F.R. § 250.191, this investigation is a fact-finding proceeding with no adverse parties. The purpose of this investigation report is to identify the probable cause(s) and any contributing issues that led to the pollution event. This investigation report also provides recommendations on how to strengthen the implementation of subsea safety and environment regulations. For this report, the "Panel" will refer to the Panel Investigation Team listed above.

Companies Involved

Fieldwood Energy, LLC ("Fieldwood")

Fieldwood was an independent exploration and production company responsible for operating numerous platforms and wells in the GOM. Its oil and gas activities included both shallow and deepwater operations, including subsea production systems.

At the time of the incident, Fieldwood was the majority record title interest holder and operator for GC Block 40, which included the K1 Well. As the designated operator of GC Block 40, Fieldwood had full authority to act on behalf of the lessee(s)/operating rights owner(s) to fulfill the obligations under OCSLA, in compliance with the terms and conditions of the lease, laws, and applicable regulations.

Effective in August 2021, Fieldwood's majority record title interest in GC Block 40 was assigned to QuarterNorth Energy LLC. Subsequently, all record title interest holders designated QuarterNorth Energy LLC as the Operator of GC Block 40. For the purposes of this report, the

[1] Designated Panel Chair

BSEE Panel will continue to refer to Fieldwood as the Operator of the K1 Well, as they were at the time of the incident.

Subsea Integration Alliance (SIA)

SIA is a partnership between OneSubsea and Subsea 7 to jointly design, develop, and deliver integrated subsea development solutions. According to its website, SIA offers a combination of subsurface expertise, subsea production systems (SPS), subsea processing systems, subsea umbilicals, risers, and flowlines systems (SURF), and life of field services. Fieldwood signed an Engineering, Procurement, Construction and Installation (EPCI) contract with SIA for the Katmai Development.

Subsea 7 (SS7)

According to its website, SS7 is a global leader in delivering offshore projects and services for the evolving energy industry. SS7 provides a full energy lifecycle of services, including project conception, design, engineering, procurement and fabrication, installation and commissioning, maintenance, and decommissioning. SS7 was responsible for the engineering, procurement, construction, and installation of the Katmai K1 Well Jumper.

OneSubsea (OSS)

OSS is a Schlumberger company that provides products and services to oil and gas operators. The company operates in the following six divisions: integrated solutions, production systems, processing systems, control systems, swivel and marine systems, and subsea services. The company was formed through the integration of the Cameron subsea section and Schlumberger-owned Framo Engineering. OSS supplied the Multi-Phase Flow Meter (MPFM) and Collet Vertical Connections (CVCs) that were used by New Industries to fabricate the Katmai K1 Jumper. OSS did not supply the Katmai K1 MPFM flange fasteners.

New Industries, Inc. (“New Industries”)

According to its website, New Industries was established to provide steel fabrication services to the offshore energy and marine industries. New Industries fabricated the Katmai K1 Jumper in Morgan City, Louisiana. New Industries was responsible for supplying the MPFM fasteners (studs and nuts) for fabrication.

Background

In 2012, Noble Energy, Inc. ("Noble") acquired the OCS-G 34536 Lease ("Lease"), which covers approximately 5,760 acres of submerged lands of the OCS. The Lease encompasses all of GC Block 40 in the GOM Central Planning Area (see Figure 1). The K1 Well is located approximately 140 miles south of New Orleans, Louisiana, in about 2,082 feet of water depth.

Between January 14, 2014, and September 16, 2014, Noble drilled the K1 Well. On March 9, 2017, BSEE accepted Noble's proposed Deepwater Operations Plan (DWOP) to develop the Katmai Field. The plan included the production of one subsea well (K1 Well) to the Tarantula production facility (Host Facility) in South Timbalier Area (ST) Block 308, as described in the next section of this report.

Effective January 1, 2018, Fieldwood became the majority record title interest holder for GC Block 40,[2] which included the K1 Well. All record title interest holders designated Fieldwood as the Operator of GC Block 40. On September 28, 2018, Fieldwood signed an EPCI contract with SIA for the Katmai Development. On June 11, 2019, Fieldwood submitted a revised DWOP to BSEE to further develop the Katmai Field by including a second subsea well. The plan included the production of two subsea wells.

[2] Record title interest holders also included ILX Prospect Katmai, LLC (25%) and Ridgewood Katmai, LLC (25%).

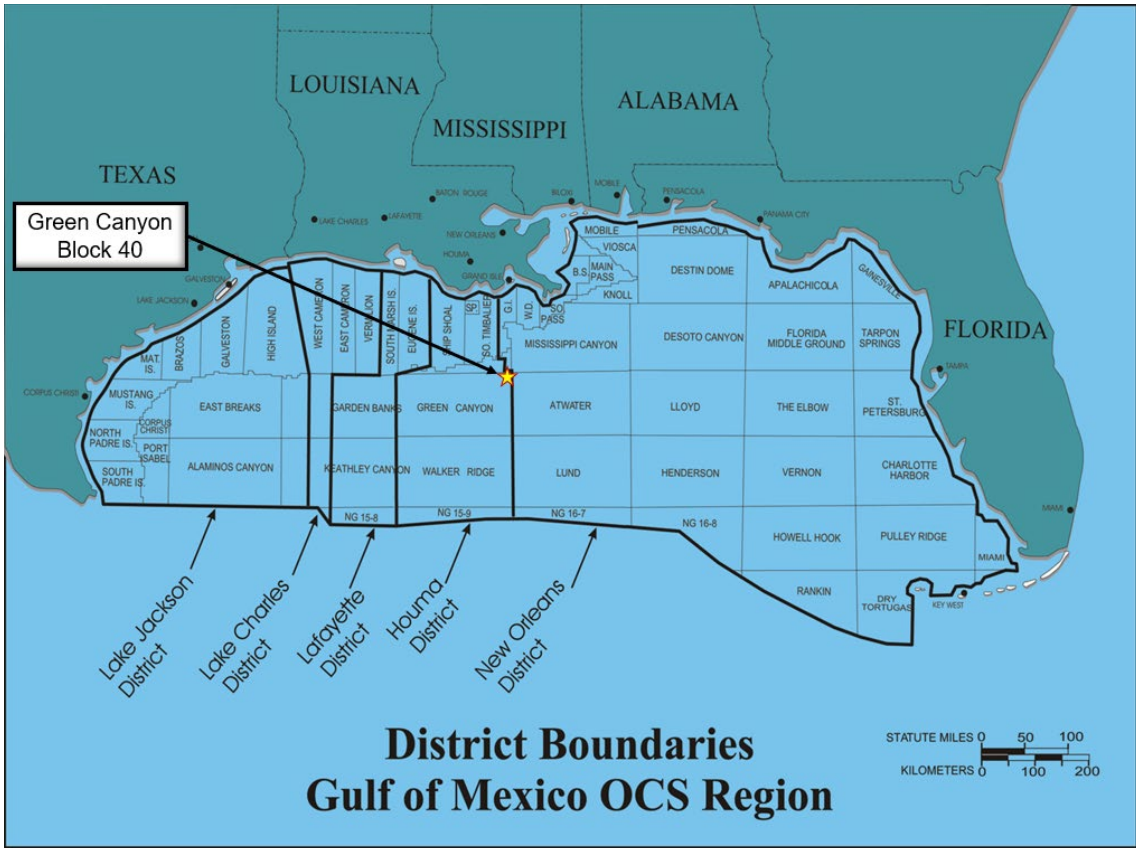

Figure 1: Approximate Lease Location of K1 Well

Katmai Field Development

The Katmai Field is located in GC Blocks 39, 40, and 41, as well as in Ewing Bank Area (EB) Blocks 1009, 1010, and 1011. In 2014, the Katmai Field was initially discovered by drilling the K1 Exploration Well located in GC Block 40. A second appraisal/development well, GC Block 40 #2 (K2 Well), was drilled at the mudline surface location of GC Block 39. The K2 Well was plugged and abandoned at the time of the incident.

Oil production from the two wells in the Katmai Field is planned to be transported to the Host Facility in ST Block 308 via one dedicated single 8-inch x 12-inch pipe-in-pipe (PIP) flowline (PSN20202/ 20203). This approximately 26-mile long Katmai Flowline starts at the Katmai K1 Pipeline-End-Termination (K1 PLET) located within 100 feet of the K1 Well in GC Block 40 (see Figure 2).

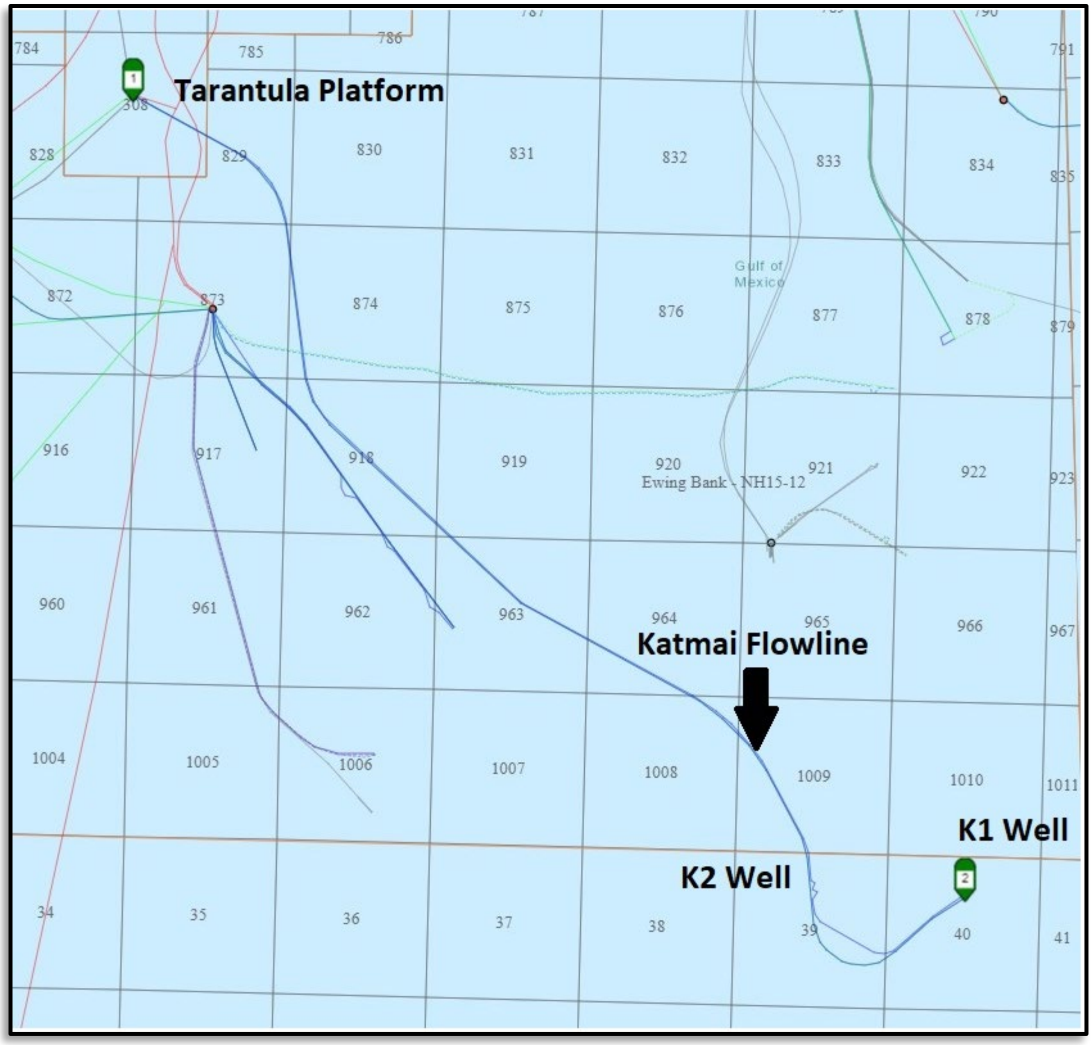

Figure 2: Katmai Field Flowline, Wells, and Tarantula Platform

Katmai Subsea Production Flow

Katmai subsea production initiates in the K1 Well. The K1 Well has a maximum allowable working pressure (MAWP) rating of 15,000 psi. The K1 Well has a surface-controlled subsurface safety valve (SCSSV) on the vertical run of the well's production tubing. The K1 Tree is equipped with a remotely actuated Production Master Valve (PMV), Production Wing Valve (PWV), Production Choke Valve (PCV), and Flowline Isolation Valve (FLIV), which are upstream of the K1 Jumper (see Figure 3).

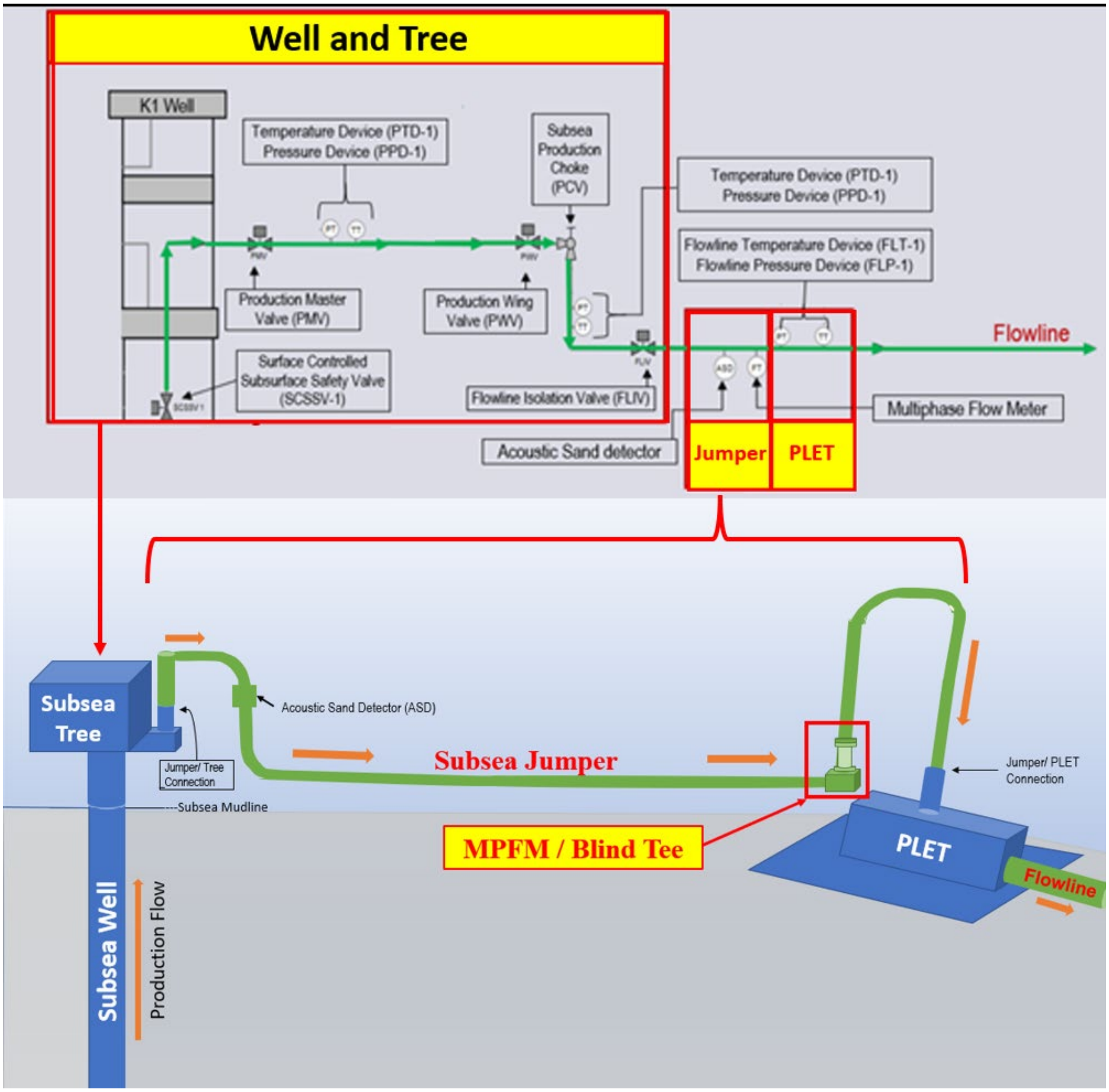

Figure 3: General Production Flow Schematic and Arrangement of Well, Tree, Jumper, MPFM, PLET, and Flowline

Production flow continued through the K1 Tree, and then through the K1 Jumper. The K1 Jumper, which included an MPFM installed in-line with the jumper, was directly connected to the K1 Tree and the K1 PLET via Collet Vertical Connections (CVC).

Production flowed from the K1 Jumper through the K1 PLET and then entered the Katmai Flowline. The Katmai Flowline runs on the seafloor approximately four miles before the K2 Well production piping ties in at the Inline Sled (ILS). Once the K2 Well initiates production, the K2 Well production will flow through the K2 Jumper into the ILS and will be commingled[3] with K1 Well production in the Katmai Flowline.

The dedicated single 8-inch x 12-inch PIP flowline runs from the ILS approximately 22 miles to a flange connection at the riser base. The commingled production flow travels up the riser to the Host Facility. At the time of the incident, the Host Facility served as the primary production allocation point for the K1 Well.

K1 Well Jumper

The Katmai K1 Jumper (PSN 20199) facilitates the production of fluid flowing from the K1 Well to the Katmai K1 PLET. The K1 Jumper was designed to operate under maximum internal pressure of 15,000 psi and was approximately 91.9 feet long from the centerline of one end connection to the centerline of the other end connection.

The "M"-shaped rigid well jumper included an acoustic sand detector (ASD) and an MPFM. The X-65 grade pipe had an outer diameter (OD) equal to 8.625 inches and included Inconel 625 internal pipe cladding. A 3.4-inch thick C25 pipe insulation covered the tubular OD.

Multiphase Flowmeter / Blind Tee

The Katmai K1 Jumper design included a OneSubsea Vx Omni Multiphase Flowmeter (MPFM) to assist in well testing and reservoir management. The MPFM proprietary design enables the instrument to measure the individual oil, gas, and water phase flowrates without the need for prior phase separation, safety systems, or process control.[4]

K1 Well Production flowed through the K1 Jumper "belly section" and into the Blind Tee. Inside the Blind Tee, production flow made a 90-degree transition from horizontal to vertical, then continued up through the MPFM and toward an inverted "U" and into the PLET (see Figure 3).

The MPFM was flange-connected on both ends in line with the K1 Jumper and was designed to receive the turbulent production flow exiting the K1 Jumper's Blind Tee. The MPFM bottom flange was fastened with eight studs and eight nuts to the Blind Tee. The eight studs were each screwed into the body of the Blind Tee, extended through the MPFM bottom flange, and secured in place with a nut. The MPFM exit nozzle (upper flange) design was a flange-to-flange connection that fastened together with eight studs and 16 nuts. The design called for a gasket installed in both the MPFM upper and lower flange connections.

The MPFM was not meant for allocation level measurement and was not a required component for the K1 Well to begin production. According to Fieldwood, the MPFM was not yet operational at the time of the incident due to data processing issues. The Katmai Field

[3] Commingled production refers to the simultaneous production of hydrocarbon from multiple reservoirs through a single production conduit.
[4] At the time of the incident the MPFM was not working as designed. The Host Facility operators could not acquire data from the MPFM.

development plan included future commingled production flow in the Katmai Flowline from the K1 and K2 Wells. In this case of commingled production, the MPFM would serve as a reservoir management device measuring fluid production flow from the K1 Well.

K1 PLET

The Katmai K1 Pipeline End Termination (K1 PLET) assembly marks the origin of the Katmai 8-inch x 12-inch PIP flowline (Pipeline Segment Number (PSN) 20202/20203). The K1 Jumper connects directly to the K1 PLET (see Figure 3).

K1 PLET consists of three sections: (1) the piping header, which consists of the in-line piping system, valves, fittings, bends, bubs, anchor forgings, insulation, etc., (2) the Upper Structure/Pipe Skid, and (3) the Mudmat. The Katmai subsea design allows for K1 PLET's Piping Header and the Upper Structure/ Pipe Skid to slide on the Mudmat to account for thermal expansion and contraction of the Katmai Flowline.

Timeline

Pre-Production History

On January 25 and 26, 2020, Fieldwood installed the K1 Tree. On March 22, 2020, the K1 Jumper was successfully connected to the K1 PLET and the K1 Tree. Following the connection, the K1 Jumper successfully passed a 15,000-psi leak test. The pressure test included internally pressuring the jumper to above 15,000 psi and holding for two hours. After the jumper installation, the K1 Well completion operations were initiated, which were completed on April 7, 2020.

Initial Production

On June 18, 2020, the K1 Well commenced its first production. Within the first two days, there was an apparent obstruction in the flowline, which required a few days of troubleshooting. The production crew utilized Monoethylene Glycol (MEG) from the Host Facility to clear the obstruction in the flowline. K1 Well production was then reestablished.

Between June 18 and July 24, the K1 Well production was shut-in six times, including unplanned shut-in events due to issues with process equipment on the Host Facility. Two of those shut-ins were in the days leading up to the incident, on July 21 and July 24, 2020.

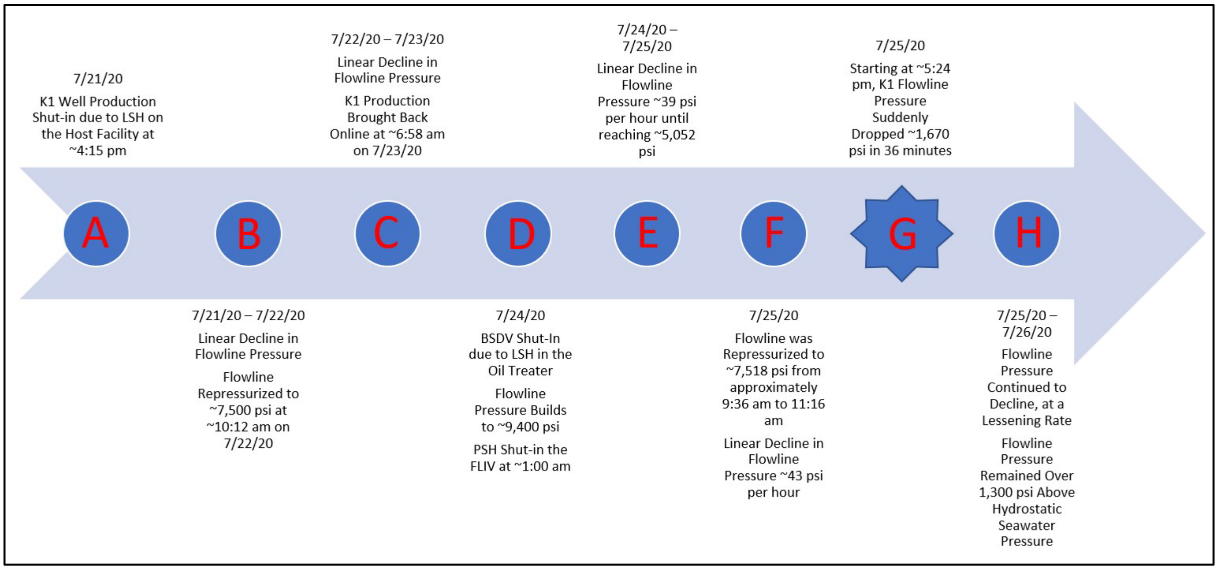

Figure 4: Katmai Flowline Timeline

On July 21, 2020, at approximately 4:15 p.m., K1 Well Production was shut-in due to a level safety high (LSH) alarm on the Host Facility (see Figure 4, A). A decision was made to leave the well shut-in for 12 hours to conduct a Pressure Build-Up Test (PBU). With the well shut-in, Fieldwood indicated standard thermal cooling of the flowline caused a linear decline in the flowline pressure (see Figure 4, B).[5]

On July 22, 2020, at approximately 10:12 a.m., the Katmai Flowline was re-pressurized to 7,500 psi, using the well for pressure support.[6] After re-pressurization with the well shut-in, the flowline pressure charted a linear pressure decline.

On July 23, 2020, at approximately 6:58 a.m., platform operators brought the K1 Well production back on. The well continued flowing until early the next day (see Figure 4, C).

Early in the morning of July 24, 2020, while the K1 Well was flowing, the boarding shutdown valve (BSDV) shut-in at the Host Facility due to a LSH in the oil treater (see Figure 4, D). This caused the flowline pressure to build up to over 9,400 psi at the PLET, tripping the PSH and shutting in the K1 Tree Flowline Isolation Valve (FLIV).

Fieldwood reported that Host Facility operators bled pressure from the flowline to prepare for the restart but discovered a leak on the glycol reboiler, leaving the well shut-in. They indicated that the K1 Well was shut-in at the FLIV and PCV, while the PMV, PWV, and SCSSV remained open.

[5] With the well shut-in, the hot reservoir fluids remained trapped in the subsea flowline. The fluid's heat slowly transferred through the PIP flowline to the sea water. The internal flowline fluid temperature gauge tracked the thermal cooling of the flowline fluids. Thermal cooling often results in an internal flowline pressure decrease.

[6] The Katmai Flowline pressure downstream of the K1 Tree needed to be increased above 7,200 psi in order to maintain the pressure across the K1 Tree Choke (Production Control Valve (PCV)) within the Original Equipment Manufacturer (OEM) design allowable limits. Additionally, the control room operators needed to ensure the flowline pressure stayed above the bubble point pressure.

While the K1 Well was shut-in, the flowline pressure followed a linear pressure decline which Fieldwood indicated was due to the flowline thermal cooling effect. The flowline pressure decreased to 5,052 psi, which was approximately 39 psi per hour drop rate over the previous 24 hours (see Figure 4, E).

On July 25, 2020, at approximately 9:36 a.m., platform personnel opened the FLIV and PCV to repressurize (or re-charge) the Katmai Flowline (Katmai Flowline pressure = 5,052 psi) using pressure from the K1 Well. By repressurizing the Katmai Flowline, the platform personnel were able to reduce the differential pressure observed at the subsea choke. Fieldwood reported that at 11:16 a.m., the flowline re-pressurization was completed, and pressure was approximately 7,518 psi (see Figure 4, F).

For the next six hours, pressure in the flowline dropped steadily at a rate of about 43 psi per hour. The Control Room Operators (CROs) attributed the steady pressure decay to thermal depressurization from the cooling subsea flowline.

The Incident

On July 25, 2020, at 5:24 p.m., the Katmai Flowline pressure suddenly decreased (see Figure 4, G). Just before 5:24 p.m., the Katmai Flowline pressure measured at the K1 PLET was 7,252 psi. By 6:00 p.m., the pressure in the Katmai Flowline had dropped to approximately 5,579.7 psi—over 1,670 psi in only 36 minutes. According to BSEE interviews, two CROs said they discovered the sudden decrease in the Katmai Flowline pressure when they returned to the control room at approximately 6:00 p.m.

The CROs initially attempted to identify the reason for this pressure drop by checking the topside equipment. After confirming it was not caused by the topside equipment, they notified their Production Team Lead, then the Offshore Production Manager on the platform, followed by the onshore Superintendent, Production Engineer, and Subsea Flow Lead to discuss further. From this discussion, Fieldwood attempted to locate nearby resources for a flyover or vessel survey of the water surface above the K1 Well. This attempt was unsuccessful.

Discussions about the pressure drop continued with a larger group, including the Deepwater (DW) Asset Manager, Superintendent, Production Engineer, Host Facility personnel, Subsea Flowline Lead, Third Party Flow Assurance expert, DW Projects Manager, and DW Subsea Engineer. The team analyzed the available data but could not confirm the cause of the sudden pressure decline.

Discussions included the possibility of a leak or a hydrate formation, among other possibilities. The flowline pressure was not trending toward the ambient pressure of the sea (hydrostatic pressure line) (~930 psi) (see Figure 4, H). The group decided to monitor the pressure trend through the night while waiting on a flyover and vessel survey. They decided not to repressurize the flowline pending those inspection results and confirmation of subsea integrity.

Post-Incident

On July 26, 2020, Fieldwood could not mobilize a flight due to weather. However, at about 9:00 a.m., an offshore supply vessel (OSV) arrived at the Host Facility and was re-routed to follow the flowline back to GC Block 40 to perform a sheen survey and evaluate the potential of a leak occurring. Shortly after 12:30 p.m., personnel on the vessel observed a rainbow-colored sheen on the water surface near the K1 Well. During a 12:30 p.m. conference call with the same team as the previous evening, Fieldwood personnel evaluating the pressure drop were informed of the oil sheen on the water, reportedly within a mile of the K1 Well located in GC Block 40.

Following the report of a sheen on the water near the K1 Well, Fieldwood ordered the closure of the K1 Well's PMV, PWV, and SCSSV, and initiated blowdown of the flowline to the Host Facility to relieve pressure and remove fluids from the flowline. The blowdown, which required a platform restart, commenced at approximately 1:29 p.m. Fieldwood also sourced a remotely operated vehicle (ROV) to inspect the subsea well components and initiated an incident management team (IMT).

Fieldwood estimated the total volume of oil released was 479 barrels, which is calculated based on the volume of oil recovered from the flowline. The incident was reported to the National Response Center (NRC).

On July 26, 2020, at 8:45 p.m. a Marine Pollution Surveillance Report (MPSR) was issued by the NOAA Satellite Analysis Branch (SAB) showing an anomaly of possible oil a few miles from the K1 Well in GC Block 40 (Figure 5). The report displayed a satellite image from July 26, 2020, at 6:59 p.m., which the BSEE Panel concluded is related to the NRC report describing the discovery of a large slick coming from a flowline associated with an offshore oil well in GC Block 40. The anomaly was measured at 37.23 nautical miles in length and 11.41 nm wide (measured as a whole), with a 147.9km^2 total area of possible oil.

The BSEE Panel also contacted the NOAA SAB and requested a review of the archived data above the jumper breach to reveal any evidence of a possible sheen before the discovery on July 25, 2020. The BSEE Panel concluded that the available imagery did not identify any anomalies related to this particular event before its discovery on July 25, 2020.

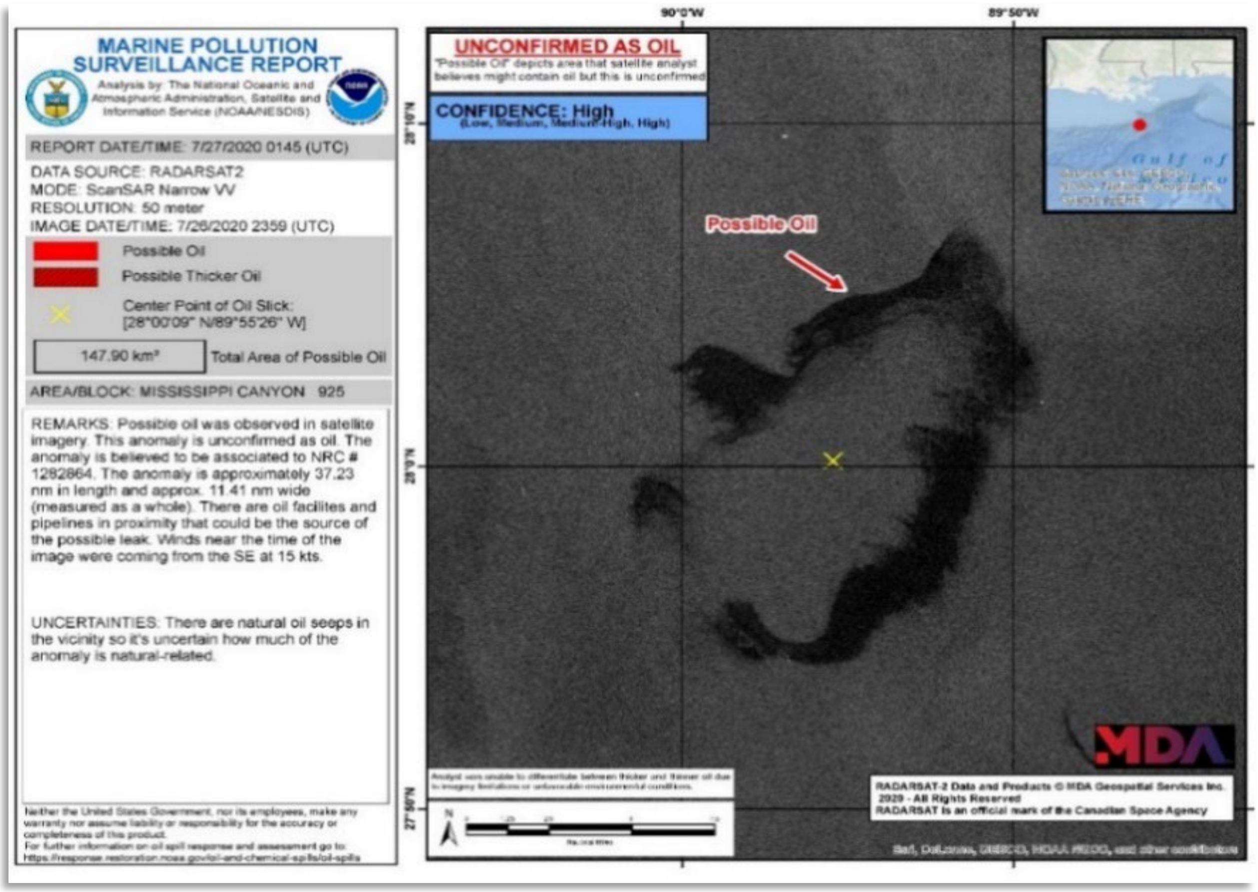

Figure 5: NOAA MPSR dated July 27, 2020, 0145 (UTC)

On July 27, 2020, an ROV deployed from a motor vessel in GC Block 40 performed an inspection of the subsea components downstream of the K1 Tree. ROV live video surveillance identified the potential leak source at or around the MPFM/Blind Tee connection area (Figure 6).

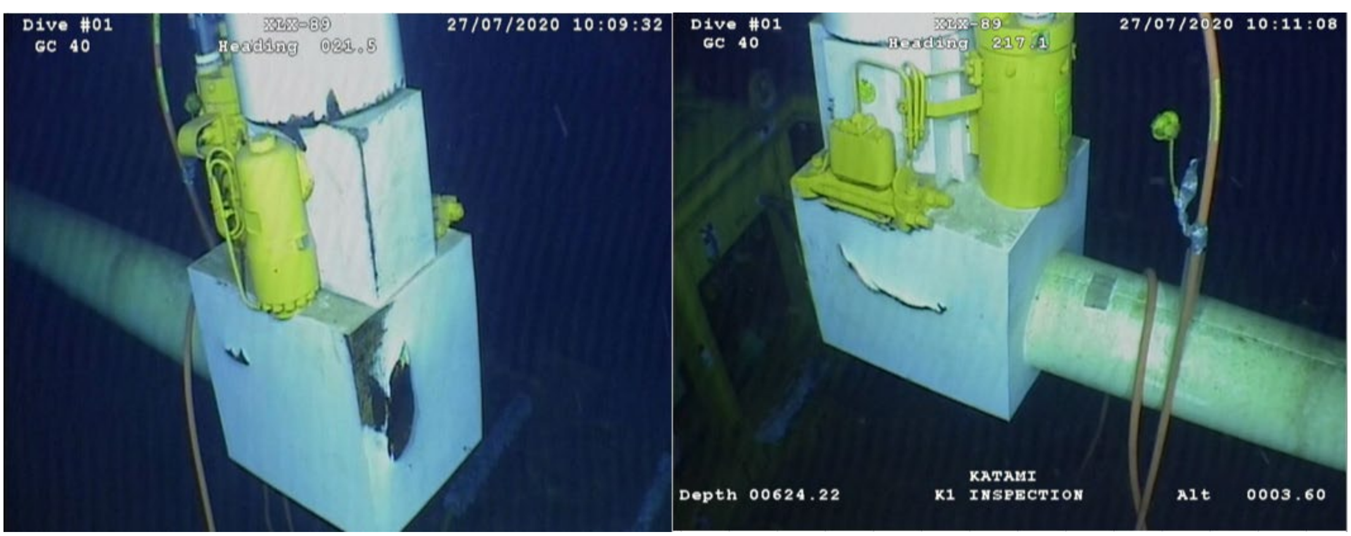

Figure 6: Images from ROV video on July 27, 2020

During the recovery and transportation process, the K1 Jumper was cut into four sections. Section Two, which included the MPFM and Blind Tee, was shipped to Stress Engineering Services, Inc. (SES) for failure analysis.

The BSEE Investigation

A BSEE Panel was convened to conduct a full investigation of the incident. The BSEE Panel reviewed electronic and written material, met weekly with the Fieldwood Incident Investigation Team (IIT) to review the testing process and findings, conducted interviews of personnel, and observed the operation of relevant activities. The following sections summarize the Panel's findings.

Engineering, Procurement, Construction, and Installation

On September 28, 2018, Fieldwood signed an Engineering, Procurement, Construction, and Installation (EPCI) contract with Subsea Integration Alliance (SIA) for the Katmai Development. SIA consisted of an alliance between Subsea 7 (SS7) and OneSubsea (OSS).

SS7 was the primary contractor for the K1 Jumper, which was included in the EPCI contract. SS7 was responsible for the engineering, procurement, construction, and installation of the K1 Jumper. OSS supplied the Multiphase Flowmeter (MPFM) and the K1 Jumper end connections. SS7 subcontracted the jumper fabrication and the Factory Acceptance Testing (FAT) to New Industries.

The Subsea, Umbilical, Riser, and Flowline (SURF) systems were delivered through the EPCI contract. The full scope of the EPCI contract to be performed under the OSS/SS7 Alliance was described in the Inspection and Test Plan (ITP), and consisted of the following elements:

- Definition of the proposed pipeline and umbilical routing.
- Design and installation engineering of flowline and control system.
- Design and procurement of all items necessary to fabricate the complete flowline system and control system.
- Fabrication of all items required to install the complete flowline system and control system.
- Installation and pre-commissioning of the complete flowline system and control system up to the well trees.

K1 PLET Installation

During the installation of the K1 Well in 2014 by Noble, excess casing cement hardened on the mudline in areas around the well. According to Fieldwood, the extent of the cement coverage before the installation of the K1 Pipeline End Termination (PLET) was unknown.

On January 27, 2020, the K1 PLET installation was unsuccessful in achieving the expected PLET mudmat penetration into the seafloor mudline. A survey and samples taken confirmed the presence of a 4" thick cement slab under the K1 PLET just below a layer of mudline silt. The cement was present in a 40 ft radius around the PLET. The silt layer on top of the cement varied in thickness around the PLET from 1 inch to 35 inches.

In addition, metrology scans found that the PLET landed outside of the designated target area. Therefore, the K1 Jumper had to be built approximately six feet longer than its original design. The SS7 generated a revised design to account for the extra length.

To fix the PLET mudmat foundation issue, a grout remediation procedure was performed between February 28, and March 5, 2020. An engineering assessment of the PLET mudmat foundation was performed after the grout remediation procedure. The engineering assessment confirmed the K1 PLET grout remediation was successful, and the K1 PLET foundation stability was approved.

Jumper Design

On April 22, 2019, SS7, representing the SIA, generated the Jumper Design Basis document[7] which included the design data and methodologies used to analyze the Katmai Well Jumpers.

On June 3, 2019, SS7 issued the Jumper Design Report. The report presented the design data and methodologies and illustrated the results of the static and fatigue analyses of both the K1 and K2 Jumper designs. The K1 Jumper was modeled and analyzed with a software package using data from the Basis of Design (BOD) document. After the Jumper Design Report was issued, SS7 made several engineering changes to the design. SS7 documented and analyzed the design changes which included: installing K1 Jumper pipe reducers, lowering the K1 Jumper shoulder height on the K1 Tree side by one foot, and increasing the jumper length due to the K1 PLET landing outside the target box.

The Katmai K1 Arrangement and Details 8" Production Well Jumper K1 document, commonly referred to as the "General Arrangement Drawing," was issued pre-metrology.[8] This document is the jumper design resulting from the Jumper Design Report analysis. Later in this report, the General Arrangement Drawing is discussed in greater detail.

On March 9, 2020, SS7 generated the "Dimensional Requirements 8" Production Well Jumper K1 Post Metrology" drawing ("As Built (rev1) Drawing") which incorporated the updated metrology information in the K1 Jumper design. This drawing was used to perform the metrology welds on the jumper during fabrication.

On June 6, 2020, the As Built (rev1) Drawing was updated after the K1 Jumper installation on March 22, 2020. The new drawing ("As Built (rev2) Drawing") included the installed orientation of the MPFM.

MPFM's Interface Drawing

[7] The Jumper Design Basis document is also referred to as the Basis of Design (BOD) document.
[8] Metrology is the procedure for acquiring the subsea measurement data required for the subsea jumper design and fabrication.

OSS, the MPFM Original Equipment Manufacturer (OEM), provided to SS7 the OneSubsea Vx Omni Katmai Interface Drawing, commonly called the "Interface Drawing." The drawing provided important MPFM information for the K1 Jumper design.

The Katmai K1 (PSN 20199) and K2 Jumper (PSN 20198) designs each included an MPFM that was flange-connected in-line with the jumper. According to an SS7 representative, he did not typically design GOM subsea jumpers with an MPFM top and bottom flange connection. Instead, MPFMs could be welded to the jumper. During a BSEE interview, an SS7 engineering representative indicated the first time he saw jumpers with bolted connections [like the MPFM flange] was working for SS7, and that it's something he had not seen in the past; but it did not mean it was not typically done.

The Interface Drawing included the flange connection load capacities in the "Allowable Nozzle Loads at Inlet and Outlet" table, commonly called the "Nozzle Load Table." The MPFM inlet and outlet nozzles are also described as the lower (inlet) and upper (outlet) flanges. The Nozzle Load Table included the following MPFM flange load capacities: the Axial Force, the Shear Force, the Bending Moment, and the Torsional Moment. These load capacities were used for the Katmai K1 Jumper design.

According to the Fieldwood IIT investigation report and the SES investigation report, the OSS's Nozzle Load Table was conservative. As discussed in the Fieldwood IIT investigation report, API technical reports offer guidance on only three flange loads: tension, pressure, and bending moment. OSS provided the Torsional Moment and the Shear Force capacities, which are not defined in API technical reports. According to the Fieldwood IIT investigation report, the OSS-generated load capacities for Torsional Moment and Shear Force were overly conservative in part due to the industry not having a standard for defining flange shear and torsion capacities.

The load capacities listed on the Nozzle Load Table assume a proper flange connection installation. OSS included a warning on the drawing, stating the nozzle loads listed in the table are calculated assuming:

- Nickel alloy 718 fasteners with specified minimum yield strength (SMYS) of 120 ksi are used on API flanges.
- Fasteners are tightened to 73% of yield strength (as per API 17D).
- Flanges are clean (no grease/lubricant) during installation.
- Provided Nozzle Loads Table is only valid when given assumptions are met.

The drawing specified the MPFM to be installed at a specific orientation to the Blind Tee (90-degree bend) inlet. The MPFM Interface Drawing showed two possible Blind Tee inlet orientation options, each 180 degrees from the other.

K1 Jumper General Arrangement Drawing

On January 17, 2020, SS7 issued the "Arrangement and Details 8" Production Well Jumper K1" document, commonly referred to as the "General Arrangement Drawing." It was the jumper design resulting from the Jumper Design Report analysis and was used for procurement, planning, and fabrication bidding purposes. The Jumper Design Report, along with the General Arrangement Drawing, were released before K1 PLET installation and metrology. The General

Arrangement Drawing included the bill of materials, design notes, and jumper arrangement details.

SS7's standard operating procedure included a technical review process for quality control before releasing the General Arrangement Drawing document. This process involved a review by engineers and engineer management.

During a BSEE interview, an SS7 engineering manager indicated that the drawing was flagged during the technical review process for not including the MPFM flange fasteners' SMYS. However, the action item was not corrected before SS7 engineering management approval and before issuing for construction. According to an SS7 engineering representative during a BSEE interview, the technical review process did not include a review by a metallurgist.

The General Arrangement Drawing is an important document in the investigation because it is the only document providing procurement specifications for the MPFM studs, nuts, and ring gaskets. The information used for ordering the MPFM studs, nuts, and ring gasket was limited to the material descriptions in the "Bill of Materials" section of the General Arrangement Drawing. An SS7 engineering representative confirmed during BSEE Panel Interviews that the General Arrangement Drawing was the only document sent to New Industries that contained procurement information regarding purchasing the MPFM flange, studs, and nuts.

The MPFM flange studs and nuts specified in the document were described in the document's "Bill of Materials" section.

QTY	Description	Material
(8)	Stud, 1 ¾ -5 UNC x 13 ½" LG., All Thread (Xylan Coated)	Inconel 718
(8)	Stud, 1 ¾ -5 UNC x 9 ¾" LG., All Thread (Xylan Coated)	Inconel 718
(24)	Heavy Hex Nut, 1 ¾ -5 UNC (Xylan Coated)	

This section included a description of the stud thickness, stud length, thread count, and coating, as well as the material. However, the studs' SMYSand heat treatment requirements were not included in the General Arrangement Drawing. The document did not include an API or ASTM standard for the material, Inconel 718. This was a significant finding in the investigation.

The SMYS of 120 ksi, which was provided on the Interface Drawing but not transferred to the General Arrangement Drawing that was used for procurement, would not specifically have indicated the heat treatment properties for the studs, but it could have directed someone to the correct standard which had the heat-treating properties in it.

The General Arrangement Drawing issued for construction also specified for the MPFM to be installed 90 degrees out of orientation from the OEM specifications listed on the Interface Drawing. This discrepancy was not identified before K1 Jumper fabrication. Additional information about the MPFM orientation is discussed later in this report.

The General Arrangement Drawing further specified a non-API 6A thread form for the MPFM flange studs. The API-recommended thread form for studs used for the API flange listed in the Bill of Materials was 8UN (8 threads/inch). The MPFM flange stud thread form specified on the

General Arrangement Drawing's Bill of Materials was 5UNC (5 threads/inch). The Panel did not find this to be a contributing factor for the jumper failure.

In addition, the General Arrangement Drawing prescribed the MPFM flange nut torque of 3,391 FT-LBS but did not provide the methodology for generating the torque value. The post-incident Fieldwood IIT report indicates the torque was derived from averaging three computational methods (Mil-HDBK-60, Shigley, and API 6A) together. The formulas assume the following:

- Stud's SMYS = 120 ksi.[9] Stud (desired) pre-stress = (73% of stud SMYS) = 87.6 ksi.
- Friction coefficient: [(nut to flange face) = 0.13; (nut to stud) = 0.07].
- Stud thread form = 8 threads/inch.

Procurement and Fabrication

Fieldwood's EPCI contract with SIA included engineering, procurement, construction, and installation of the Katmai K1 Well Jumper. SS7, representing SIA, was the primary contractor for the K1 Well Jumper. SS7 subcontracted the jumper fabrication to New Industries in Morgan City, Louisiana.

SS7 arranged for all Katmai K1 Jumper components (K1 Jumper Fabrication Kit) to be delivered to New Industries. In August 2019, the Blind Tee and Target Tee were delivered to the New Industries fabrication yard. OSS supplied the jumper end connectors, the ROV Back Seal Test Panel, and the MPFM with flanges.

SS7 sub-contracted out the responsibility of procuring the MPFM studs and nuts to New Industries. New Industries ordered the studs and nuts from a supplier. The associated Material Test Reports (MTR) were included with the orders.

Inspection and Test Plan (ITP)

New Industries generated the "Katmai Field Development Inspection and Test Plan (ITP) for the Jumper Fabrication." New Industries, SS7, and Fieldwood agreed to this document.

The Katmai Jumper ITP is a critical document covering the kit and final fabrication, corrosion coating, FAT/SIT (System Integration Test) testing, and loadout inspection points for the Katmai Jumpers. In addition, the document:

- Identifies the 39 stages requiring sign-off during the jumper fabrication.
- Clarifies the requirement agreed upon for each stage.
- Clarifies the responsibility of each company for each stage.
- Serves as the official sign-off and date document.

Each stage offers a sign-off section for representatives from New Industries, SS7, and Fieldwood. The representatives' responsibility is predetermined and agreed upon for each step. The ITP "Inspection Code Legend" defines seven possible inspection roles (see Figure 7).

[9] Inconel 718 material with 120 ksi SMYS is not in compliance with ASTM B637 heat-treatment specification.

INSPECTION CODE LEGEND	
Review (R)	A "Review" point is defined as a point in the manufacturing or testing cycle at which a record of the activity is required. The nominated party is required to review / endorse these records, which shall be presented to him at the earliest opportunity, preferably before the next activity.
Monitor (M)	A "Monitor" point is defined as a periodic check, by direct or indirect inspection, to verify conformance of the item or activity to specification. No notification is required.
Surveillance point (S)	Review, monitor or audit of activities and documentation by SUPPLIER/SUBCONTRACTOR, BUYER and CLIENT representative (or any combination) at the place of execution of the work.
Witness Point (W)	A "Witness" point is defined as a point in the manufacturing or testing cycle where the nominated party must be given the option to attend. For repetitive activities witnessing of a percentage of the total may be agreed. A formal notification has to be issued by the SUPPLIER/SUB-CONTRACTOR. If nominated party does not attend, the SUPPLIER/SUB-CONTRACTOR proceeds with works.
Witness First Off (WFO)	Same as Witness above except where duplicate operations exist, i.e. a series of butt welds; then the first of these would be subject to witnessing then subsequent activities would default to a Monitor point. BUYER or CLIENT reserve the right to perform further witnessing of such activities should they deem this to be necessary.
Hold Point (H)	A "Hold" point is defined as a point in the manufacturing or testing cycle beyond which it is not permitted to proceed without the presence of a nominated party, unless written confirmation of non-attendance has been received. A formal notification has to be issued by the SUPPLIER/SUB-CONTRACTOR. Only the organization responsible for the hold point may waive the hold point. Approval to waive specified hold points shall be documented before continuing work beyond the designated hold point.
Approval (A)	An "Approval" point is defined as point of the manufacturing or testing cycle where the SUPPLIER/SUB-CONTRACTOR is required to submit certificates for approval.

Figure 7: ITP inspection code legend

The ITP document starts with clerical-related tasks (stages 1-7), then stages eight through ten deal with purchasing and receiving verifications. The ITP includes stages for kit fabrication (stages 11-20), corrosion coating (stages 21, 22, and 30), insulation (stage 23 and 31), small-bore tubing (stage 24), final fabrication (stages 25-29 and stage 32), FAT/ SIT (stages 33-36), loadout (stages 37 and 38), and documentation (stage 39).

The ITP receiving stage (stage 10) requires a quality representative (shipping/receiving clerk) to verify the MTR documents with the items received. The acceptance criteria for receiving the purchased materials in stage 10 is, "The material shall be in accordance with the requirements of the purchase order, product specification and project requirements." The quality representative is listed as the responsible party for stage 10 and must verify the Material Test Reports (MTRs). The required verification documents include the purchase order, product specification, and project requirements (see Figure 8).

New Industries ordered the MPFM fasteners (studs and nuts) from a supplier who provided the fasteners along with the MTR documentation. The MPFM studs and nuts delivered to New Industries passed the ITP receiving stage (stage 10). The studs and nuts passed the ITP acceptance criteria by meeting the General Arrangement Drawing's Bill of Materials criteria. The Bill of Materials only included a description of the studs and nuts and did not include the desired specifications for heat treatment or SMYS. Even though the MTRs showed the studs and nuts were heat-treated in accordance with ASTM B637, the MPFM fasteners were able to pass the ITP quality check.

PROJECT / SCOPE: Katmai Field Development Project - Jumper Fabrication									
CUSTOMER: Subsea 7 / Fieldwood		PREPARED BY [redacted]		APPLICABLE JUMPER: 8" Production Well Jumper K1					
NII JOB NUMBER:	REVISION: 0	DATE: 10-Mar-2020							
No.	STAGE DESCRIPTION	CONTROLLING DOCUMENT / ACCEPTANCE CRITERIA	VERIFYING DOCUMENT/ RESPONSIBLE PARTY	New Industries		Subsea 7		Fieldwood	
				Code	Sign / Date	Code	Sign / Date	Code	Sign / Date
006	**CLERICAL** -- Submit NDE procedures. NOTE: Previously approved procedures will not be resubmitted.	Approved NDE Procedures:	Signature or Initial on this ITP. Quality Manager (or his/her designee)	H	X 17/ Mar / 2020	A	X 3/17/20	M	X 3/20/20
007	**CLERICAL** -- Provide the list of NDE personnel and their current certifications.	Personnel must be qualified in accordance with the code requirements for the code to which inspection will occur; all technicians must have current eye exams (within 1 year).	NDE technicians' certificates and current visual acuity records from their respective companies. Quality Manager (or his/her designee)	S	X 17/ Mar / 2020	S	X 3/17/20	M	X 3/20/20
008	**RECEIVING** -- Shipping / receiving to receive owner furnished equipment and materials. Customer representative to be notified when materials are received.	Any abnormalities or detrimental defects to be communicated to Subsea 7 representatives.	Certificates of conformance, MTR's, and/or delivery tickets. Note: COC's and/or MTR's received with the shipment will be included in the Vendor Data Manual when required. Quality Representative (Shipping/ Receiving clerk or his/ her designee)	S	X 17/ Mar / 2020	S	X 3/17/20	M	X 3/20/20
009	**PURCHASING** -- Material will be purchased in accordance with the requirements of the BOM and project requirements.	Material is to be purchased in accordance with the requirements of the purchase order, product specification, and project requirements.	Signature or Initial on this ITP. Project Manager (or his/ her designee)	S	X 17/ Mar / 2020	M	X 3/17/20	M	X 3/20/20
010	**RECEIVING** -- Shipping / Receiving to receive and inspect purchased materials.	Material shall be in accordance with the requirements of the purchase order, product specification, and project requirements.	Material Test Reports (MTR's). Quality Representative (Shipping/ Receiving clerk or his/ her designee)	R	X 17/ Mar / 2020	M	X 3/17/20	M	X 3/20/20

Figure 8: ITP Stages 6 through 10

The investigation also revealed the following:

- The SBX155 gaskets were installed instead of the General Arrangement Drawing-specified BX155 gaskets. However, SES post-incident evaluation did not find evidence to indicate this contributed to the MPFM flange connection failure.
- The MPFM upper flange connection was subjected to counterclockwise torque during assembly. This is discussed in the metallurgical section of this report.
- The MPFM was installed 90 degrees out of orientation from the General Arrangement Drawings specifications as well as 90 degrees out of orientation from the OEM specifications listed on the Interface Drawing. Additional information about the MPFM orientation is discussed later in this report.

The Factory Acceptance and Testing Procedure (FAT)

SS7 subcontracted New Industries to fabricate the K1 Jumper and perform the FAT. On January 23, 2020, the FAT procedure was issued for review. The FAT document defines the procedures used to demonstrate the K1 and K2 Jumpers were fabricated per the applicable drawings and specifications. As stated in the FAT document, its purpose is to "verify the jumper design and to demonstrate that all components function as intended."

On March 5, 2020, the metrology for the Katmai K1 Jumper was completed. Then on March 6, 2020, the metrology information was used to "issue for construction" the "Dimensional Requirements 8" Production Well Jumper K1 Post Metrology" drawing (As Built (rev1) Drawing). Welders used this drawing to perform the final jumper metrology welds. On March 9, 2020, the K1 Jumper metrology welds were done at the New Industries facility.

On March 10, 2020, the FAT document was issued for construction. The final FAT revision was issued for construction after the jumper metrology was complete and included references to the post metrology jumper design. The FAT dimensional verification section verified and recorded that the actual jumper dimensions were within specification to the As-Built (rev1) Drawing.

On March 12, 2020, New Industries, SS7, and Fieldwood representatives initialed next to the following procedural steps of the "Hydrostatic Testing of Piping Assembly" section of the FAT Procedure:

- FAT (Step 5): This step states, "ensure the 20k Flowmeter has been installed and studs torqued in accordance with the applicable procedure/drawing (studs shall be torqued to 3,391 ft lbs.)" and "the torque report shall be attached to this procedure."
  - 3,391 FT-LBS torque was not applied on the nuts. The field technician's torque documentation attached to the FAT reported 3,120 FT-LBS of torque applied to each nut of the MPFM top and bottom flange connection.
- FAT (Step 7): This step requires an "OSS MPFM technician to complete commissioning of MPFM, as required, per the OSS Commissioning Procedure for Subsea Multiphase Measurement System (DOC-0132726). All results shall be recorded, as required, in the OSS commissioning procedure."
  - The BSEE Panel Team requested but did not receive a copy of the OSS commissioning procedure. The MPFM was later discovered to be installed incorrectly and out of orientation. Also significant to this investigation, the MPFM flange fasteners were not in compliance with the OSS's Vx Omni Katmai Interface Drawing, which called for Nickel alloy 718 fasteners with SMYS of 120 ksi.

On March 12, 2020, the New Industries facility in Morgan City, Louisiana, successfully performed the K1 Well Jumper hydrostatic pressure test per the requirement of 30 CFR 250.1003 (b)(1). The hydro test pressure requirement included holding at least 18,750 psi (equivalent to 1.25 x MAOP) for at least 8 hours. The FAT documentation included sign-off steps during the pressure test.

On March 15, 2020, the final jumper kit fabrication was completed and loaded on an OSV for subsea installation.

K1 Jumper Fabrication Key Findings:
After analyzing the Katmai K1 Jumper fabrication evidence, the Panel found the following key discoveries:

- The General Arrangement Drawing and FAT specified MPFM flange nut make-up torque equal to 3,391 FT-LBS. Documentation attached to the FAT indicated that 3,120 FT-LBS of torque was applied. The BSEE Panel received no documentation indicating a MOC procedure was performed during the K1 Jumper fabrication. The Panel did not find evidence to indicate that the difference between the prescribed and the applied torque contributed to the MPFM flange connection failure. The impact of not performing a MOC procedure is described in the Management of Change section of this report.

- The MTRs indicate the Katmai K1 MPFM flange studs and nuts were heat-treated in accordance with the ASTM B637 standard and the SMYS = 150 ksi. This will be discussed in more detail in the metallurgical section of this report.

Jumper Installation

On March 22, 2020, the K1 Jumper was connected to the K1 PLET and the K1 Tree. The jumper installation proceeded as planned. Following the connection, a pressure test was performed that included internally pressuring the jumper to a minimum of 15,000 psi and holding for two hours. The jumper successfully passed the pressure test.

On April 7, 2020, Fieldwood performed K1 subsea well completion. The K1 Well completion operation was performed while the K1 Jumper was connected.

<u>MPFM Orientation</u>

On April 23, 2020, after the jumper installation, a non-conformance report was issued due to the MPFM installation orientation on the K1 jumper. New Industries requested and received a concession to accept the installation of the MPFM because the orientation of the flowmeter seemingly did not impact the fit or function of the jumper. However, according to a Fieldwood project engineer during his interview with the Panel, the 90-degree misalignment of the MPFM created data processing issues. Therefore, at the time of the jumper failure, the subsea operators could not receive data from the MPFM.

OSS (the MPFM OEM) issued an MPFM Interface Drawing that included detailed information about the MPFM. The drawing included the manufacturer's recommended installation orientation.

SS7 generated the K1 Jumper General Arrangement Drawing and the post-metrology As-Built K1 Jumper Drawing rev1. These drawings were used for K1 Jumper procurement and fabrication. The drawings depicted the MPFM 90 degrees out of orientation from the OEM's MPFM Interface Drawing. After the jumper fabrication and installation, SS7 generated an As-Built K1 Jumper Drawing rev2, which depicted the MPFM orientation as installed subsea. The As-Built K1 Jumper Drawing rev2 showed the MPFM was 90 degrees out of alignment with the Blind Tee compared with the MPFM Interface Drawing, and 180 degrees out of alignment compared with the General Arrangement Drawing.

Katmai K1 Production Shutdowns

On June 18, 2020, at about 9:00 a.m., Fieldwood began the first production of the K1 Well. Between June 18 and July 24, 2020, the well was shut-in six times:

1. On June 20, 2020, at 5:30 a.m., the Katmai K1 Well was shut-in due to an apparent flowline obstruction. The Katmai production team used Monoethylene Glycol (MEG) in the flowline to clear the apparent hydrate obstruction. On June 24, 2020, the team cleared the obstruction, and Fieldwood returned the well to production.

2. On July 1, 2020, the K1 Well was shut-in for approximately 12 hours to perform a Pressure Build Up (PBU) analysis test.
3. On July 9, 2020, the K1 Well was shut-in due to Temperature Safety Low (TSL) on the Host Facility alarm.
4. On July 12, 2020, the Katmai K1 Well was shut-in due to a shutdown of the rental air compressor on the Host Facility.
5. From July 21 to July 22, 2020, the Katmai K1 Well was shut-in due to a level safety high (LSH) alarm on the Host Facility.
6. On July 24, 2020, at 12:56 a.m., the Katmai K1 Well was shut-in due to an LSH on the oil treater at the Host Facility. The process shut down resulted in the BSDV closure before the FLIV closure, which caused the flowline pressure to reach its highest measurement (approximately 9,463 psi) since initial production. While preparing to restore the well to production, facility personnel observed a topside leak on the glycol reboiler.

Jumper Section Recovery

Over the next few weeks, Fieldwood planned for and recovered the K1 Jumper under the oversight of BSEE. Additional metrology surveys were performed, and Static Light Detection and Ranging (LiDAR) readings were recorded, before and after recovery. During the recovery and transportation process, the team cut the jumper into the following four sections:

Section 1: Jumper Belly
Section 2: MPFM/Blind Tee
Section 3: PLET Side
Section 4: Tree Side

On August 16, 2020, at approximately 3:00 a.m., the first ROV diamond wire cut was initiated on the K1 Jumper below the ROV Back Seal Test Panel on the K1 Tree side of the K1 Jumper. This first cut was not a full cut as it only severed through approximately 50% of the K1 Jumper's cross-sectional area. The ROV changed location after the partial cut to the planned first full cut location on the K1 Jumper. At approximately 4:00 a.m., the ROV initiated the first full K1 Jumper cut directly upstream of the Blind Tee. This cut defined the edges of cut Sections 1 and 2. The behavior of the jumper resulting from the first full cut did not indicate residual loading or angular misalignment.

The K1 Jumper recovery team proceeded with executing the K1 Jumper recovery plan. Two ROV's worked together successfully in cutting and retrieving the K1 Jumper.

After recovering the jumper sections and placing them on the recovery vessel, an ROV survey was performed covering the full length of the Katmai pipeline (40 km) from the Katmai K1 Tree to the Host Platform. The Katmai pipeline survey found no structural issues with the pipeline.

The K1 Jumper cut sections were transported to a dock in Fourchon, Louisiana, and offloaded. MPFM/ Blind Tee section was transported to Stress Engineering Services, Inc. (SES), in Waller, Texas, for failure evaluation. Cut Sections 1, 3, and 4 were shipped to another facility in Fourchon, Louisiana, for borescope inspection.

K1 PLET/Jumper Movement

LiDAR surveys indicated K1 PLET/ Jumper/ Well movement. Three subsea LiDAR scans of the K1 Jumper were used by the Panel and SES for comparison to identify K1 Jumper/K1 PLET/K1 Well movement.[10] The LiDAR surveys were:

- Jumper Metrology Scan (March 5, 2020) - LiDAR metrology survey performed after the K1 PLET remediation grouting and used for K1 Jumper metrology welds.
- Pre-Jumper Removal Scan (August 15-16, 2020) - LiDAR survey performed after the K1 Jumper failure and before removing the jumper from the PLET.
- Post-Jumper Removal Scan (performed after K1 Jumper failure and after the K1 Jumper removal.

The K1 PLET Axial Translation comparison was made between the Jumper Metrology Scan (March 5, 2020) and the Pre-Jumper Removal Scan (August 15-16, 2020) in the Pre-Jumper Removal LiDAR Report (Revision 2, Nov. 19, 2020). The Axial Translation comparison indicates the PLET settled down 0.21 foot, moved 0.11 foot along the Y-axis (in the direction of the flowline toward the platform), and moved 0.05 ft along the X-Axis (toward the K1 Well). The total movement was 0.24 foot. Based on the LiDAR survey analysis, the outer edges of the mudmat did not move.

Fieldwood's investigation report found that the K1 Jumper Basis of Design should account for additional PLET movement associated with the clearances between the PLET skid beams and the mudmat retainer/guide mechanisms.

SES FEA load simulations took into account the stresses associated with three-dimensional equipment movement. SES used the LiDAR surveys when building the simulation models. The equipment movements were factored into the FEA including the PLET's movement associated with Katmai Flowline thermal load cycles. The results from the FEA analysis are discussed in the Finite Element Analysis (FEA) section of this report.

Production Fluid Compatibility

The Katmai K1 Jumper tubular section was internally cladded with Inconel 625, offering extra protection against corrosion. During the post-incident inspection, SES did not report evidence of wall loss that might have contributed to the K1 Jumper failure. Accurate NDE Service Company and SES did not report evidence of a blockage that might have caused an overpressure event.

Subsea Leak Detection (SSLD)

For all oil and gas wells on the OCS, subsea leak detection (SSLD) is a critical component for identifying potential failures in the subsea infrastructure, and it is an integral aspect of any pollution prevention and mitigation system. SSLD of a jumper leak is especially important when

[10] On February 1, 2020, a LiDAR metrology survey was performed after setting the K1 PLET but before the K1 PLET remediation grouting. This survey was not used for K1 Jumper fabrication nor was it used for movement comparison.

the jumper is located far from its host facility (like GC Block 40 to the Host Facility) since the potential volume of release increases based on the longer length of the flowline, and visual confirmation of a discharge on the water's surface is limited when the leak location is beyond sight from the host facility.

Fieldwood had an SSLD Philosophy of safeguarding production assets against subsea leaks (prevention), process monitoring (detection), training, and empowerment (response). Fieldwood described that safeguarding production assets required a "Think Leak First" culture, which meant the initial thought of a CRO should be that an abnormal subsea process condition could be a subsea leak and should be investigated immediately. If a subsea leak was suspected at any time, the CRO had the responsibility to implement Stop Work Authority (SWA) and immediately shut-in. If a subsea leak could not be ruled out following troubleshooting, the CRO must implement SWA within four hours and shut-in, which also included Stop Production Authority.

Fieldwood's Katmai Field SSLD relied on remote monitoring devices that transmitted pressure and temperature data, as well as an ASD. This data was transmitted to the control room on the Host Facility for CROs to monitor and interpret the subsea status of the K1 components. The data also was available for viewing onshore by Fieldwood or Fieldwood-contracted personnel. Personnel depended on the output data from these monitoring devices.

On July 25, 2020, at approximately 5:24 p.m., the Katmai Flowline pressure decreased abruptly. The Panel identified that the following operational conditions existed at the time of the abrupt pressure drop:

- The K1 Well was shut-in at the K1 Tree and was the only well tied into the Katmai Flowline.
- The Host Facility was located approximately 26 miles from the K1 Well and K1 Jumper.
- The Katmai Flowline pressure was 7,252.6 psi before the pressure drop.
- Two Host Facility CROs[11] indicated they did not think anyone was in the control room at the time of the pressure drop.
- The SSLD pressure alarms were using a threshold method to alert when the pressure dropped below a certain set point. At the time of the pressure drop, the subsea device alarms were only visual and not audible.
- The MPFM was not yet operational. The MPFM data is not included in the list of SSLD monitoring devices for 'Shut-in' operational conditions according to the Fieldwood SSLD Philosophy document and operations manual.

Fieldwood's SSLD Philosophy document indicated that in the 'Shut-in' operational condition, "basic process monitoring can readily detect a subsea leak. During shut-in conditions, any pressure boundary downstream of the last isolation valve can be pressurized or depressurized (blown-down) for additional verification of the Subsea Production System (SPS) integrity."

Fieldwood documentation indicated the Tarantula / Katmai SSLD software was developed, tested, installed, and commissioned in 2020, prior to well commissioning and start-up. The SSLD

[11] According to the SSLD Philosophy, CROs were the first line of responsibility to ensure safe operation of the Subsea Production System (SPS) through continuous surveillance by means of the Subsea Production Control System (SPCS).

was revised to include a hydrostatic warning for shut-in conditions on July 7, 2020. Fieldwood's SSLD Philosophy document included multiple methods for Subsea Leak Detection, including Advanced Conditional Rate of Change (CROC) and Advanced Mass-in/ Mass-out (MIMO); as well as basic process monitoring (threshold and rate of change), basic hydrostatic verification, and basic visual surveillance. At the time of the pressure drop the well was in the 'Shut-In' operational condition and the CROC and MIMO methods were not operational. The SSLD pressure alarms were using a threshold method to alert when the pressure dropped below a certain set point. One CRO explained that the non-audible SSLD alert was triggered as a result of the pressure drop.

On July 25, 2020, at 5:24 p.m. with the K1 Well shut-in at the K1 Tree, the Katmai Flowline pressure began dropping quickly, losing over 2,200 psi within the first hour (7,252.6 psi at 5:24:38 p.m. to 5,037 psi at 6:24:39 p.m.), and almost another 1,300 psi over the next three hours (3,764.8 psi at 9:24:37 p.m.).

According to two CROs, they estimated they left the control room around 5:15 p.m. to attend a handover meeting and eat dinner, and indicated they did not think there was anyone in the control room to observe the remote monitoring devices at the time of the pressure drop.[12] They stated that leaving the control room unmanned was not the regular practice on the facility. The CROs said they normally would have someone in the control room when the well was flowing, but they did not because the well was shut-in.[13] One CRO mentioned that there was also a monitor in the supervisor's office. However, he said the supervisor was with them in their meeting, and the subsea alarms were only visual and not audible alerts. Therefore, the CROs described observing the pressure drop when they returned to the control room at approximately 6:00 p.m.; one of which said he observed the visual alarm.

After reviewing the trends, the operators began troubleshooting the topside equipment to identify a potential cause of the pressure drop, but they did not find anything. They also notified their supervisor, and then the Offshore Installation Manager (OIM). After they could not find a cause from the topside equipment, they contacted the Superintendent, Production Engineer, and Subsea Flowline Lead from Fieldwood's Houston office to discuss their findings at approximately 7:50 p.m. They discussed the situation and attempted to locate any nearby flyover/vessel survey resources, but none were available. They confirmed they had a vessel enroute to the field the following morning and scheduled a flyover for the next morning.

The conference calls continued, and more people from onshore offices became involved, including the DW Asset Manager, third-party flow assurance expert, DW Projects Manager, and DW Subsea Engineer, around 9:15 p.m. Fieldwood indicated that during this call, they evaluated flowline models designed for flow assurance against pressure decline. They were determined to be similar in trend, though not exact since original models were established for lower operating pressure. They continued to evaluate possible causes for this anomaly, including evaluating if it was due to a leak.

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[12] The Offshore Production Manager (OPM) indicated that there was a man in the control room during the 5:30 p.m. handover meeting, but thought him to be a different operator than the two interviewed by the Panel. However, statements from the two CROs interviewed by the Panel indicated that they did not think anyone was monitoring the pressure of the flowline in the control room at the time of the pressure drop.
[13] Production Report data indicates all well production to the Host Facility was shut in on the day of the incident.

Fieldwood described that the conference call participants evaluated the possibility of hydrate formation in the flowline resulting in a change in slope of pressure decline, which they determined to have a high likelihood of occurrence due to the flowline pressure dropping below bubble point and previous hydrate formation in the flowline during initial start-up. Fieldwood indicated they also evaluated the changes in the pressure decline per hour, which was decreasing, contrasted with an expectation of a continuing decline in hydrostatic pressure for a leak.

As discussed in the SSLD Philosophy, if there is a subsea leak at wells with flowing pressures greater than ambient subsea hydrostatic pressure (such as the K1 Well), when a field is shut-in and the well is isolated from the well jumper/flowline system, the internal pressure should bleed down as the hydrocarbons escape to sea. The pressure should eventually equalize, although this may take 20 to 30 minutes depending on the leak size. Regardless of the leak size, the pressure should trend towards the ambient pressure of the sea. The SSLD guidance described that a steady pressure ≥ 200 psi above the ambient pressure of the sea is evidence that a subsea leak is not present, and the system integrity is intact.

In the case of the Katmai Flowline, the flowline pressure initially decreased rapidly on the evening of July 25, 2020. However, the flowline pressure plot did not mimic a typical flowline failure, as it did not continually decline to the ambient pressure of the sea. Instead, the flowline pressure remained at least 1,300 psi above the ambient pressure of the sea. One theory that could explain this pressure trend was the MPFM flange gasket connection reengaged and sealed the leak once the differential pressure dropped to a specific point.

Fieldwood reported that on the night of July 25, 2020, the team concluded that the pressure drop was likely the result of thermal cool down in the flowline and a hydrate formation due to the lengthy shut-in and heat loss. However, they decided to monitor pressure trends throughout the night while waiting on flight and vessel surveys to confirm there was no oil on the surface.[14] Re-pressurization of the flowline was put on hold pending results of inspection(s) and confirmation of integrity. By not repressurizing, Fieldwood did not introduce additional oil or pressure to the flowline, which could have resulted in a larger release. However, the team did not depressurize the well, which would have decreased the potential volume and pressure of the remaining fluid in the flowline. Depressurizing the flowline also increases the risk of hydrates forming in the flowline. It is unknown how these actions/inactions impacted the total volume of oil that leaked into the GOM.

As the rate of pressure decrease continued to lessen throughout the evening of July 25 and the morning of July 26, 2020, the pressure remained at least 1,300 psi above ambient pressure of the sea until the blowdown began. Upon receiving confirmation of oil on the water's surface above the K1 Well on July 26, 2020, Fieldwood blew down the Katmai flowline.

Evaluations of K1 Jumper Sections 1, 3, and 4

[14] Because of the distance between the Host Facility and the K1 Well, Host Facility Personnel could not inspect for a GOM oil sheen above the K1 Well.

The inner diameter of K1 Jumper Sections 1, 3, and 4 contained a goo-like substance. Samples were analyzed and determined to be composed of asphaltenes (52.4%); paraffin (44.3%); and inorganics (3.3%). Due to the substance's composition, the cut sections could not be cleaned with just a pressure wash or lance. Xylene or Toluene was required. The use of these chemicals required a closed-loop circulation system. Fit-for-purpose engineered end caps were installed at the ends of each cut section. Special precautions were taken not to damage the cut sections while safely removing the goo-like substance and cleaning the cut sections.

Once the cut sections were cleaned, a borescope was performed on each section. Accurate NDE Service Company found no abnormalities or defects in Section 1 or 3. However, an abnormality was found inside Section 4.

SES performed additional inspections on Section 4, including setting up laser inspection equipment, making a visual and dimensional inspection of the abnormality, and performing a dye penetrant inspection. An SES welding SME classified the abnormality as a "reflectance" issue.[15] SES reported no signs of corrosion, erosion, or high-stress damage in Sections 1, 3, or 4.

Metallurgical Evaluation

Fieldwood contracted SES to investigate the Katmai K1 Jumper Section (Section 2) that failed during service. Section 2 included the MPFM and the Blind Tee. Starting on August 24, 2020, the investigation of the failure of Section 2 was initiated at the SES facility in Waller, Texas. BSEE, Fieldwood Incident Investigation Team (IIT), OSS, and SS7 representatives monitored these activities. During the metallurgical investigation, SES conducted multiple examinations on the studs, including liquid dye penetrant testing, fractography, metallography, full-scale mechanical testing, and chemical analysis.

Before removing any thermal insulation surrounding the cut section, SES performed a borescope of the inside of Section 2. The SES results of the borescope presented no evidence of blockage that might have caused an overpressure event. There also was no evidence of wall thickness loss that might have contributed to the leak. SES removed most of the thermal insulation material from around the MPFM lower flange first, before removing insulation material from around the MPFM upper flange. Nuts number 1, 2, 3, and 8 came out with the snapped (failed) studs, while nuts 4, 5, 6, and 7 were still attached to the studs. The four fractured studs (1, 2, 3, 8) were located on one side of the MPFM lower flange connection (see Figure 9 and Figure 14). The SES investigation found that all stud fractures occurred at the root of the last engaged thread at the studs' mating nuts (see Figure 11). The fractures occurred at the studs' thread root in the area where the nut and flange met. All fractures appeared to be brittle.

[15] Reflectance is the measure of the proportion of light or other radiation striking a surface which is reflected off it.

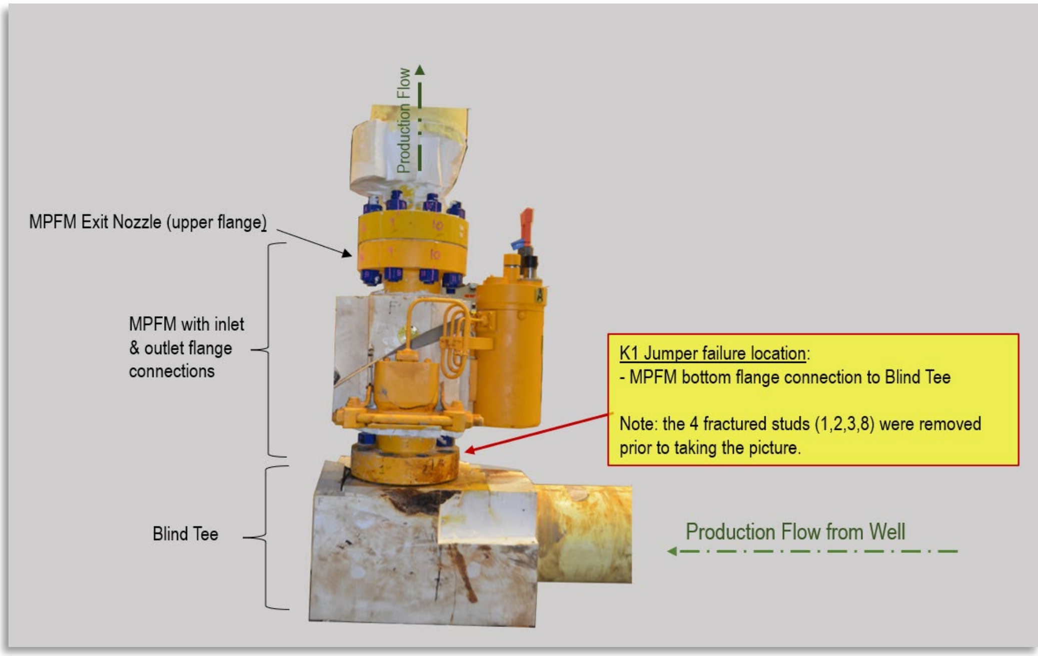

Figure 9: Katmai K1 Jumper Section #2

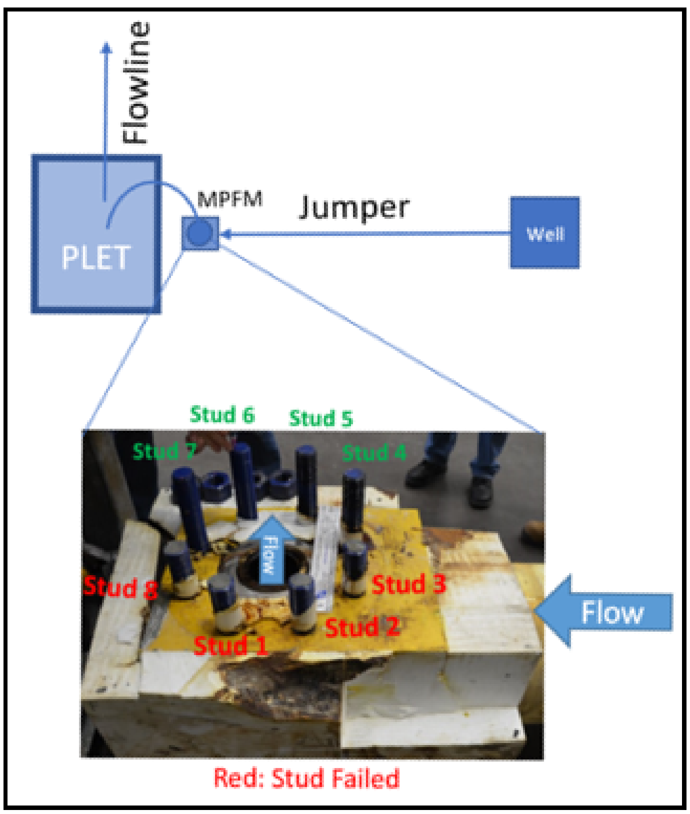

Figure 10: General depiction of the MPFM Failed Studs in Relation to Well and PLET Location

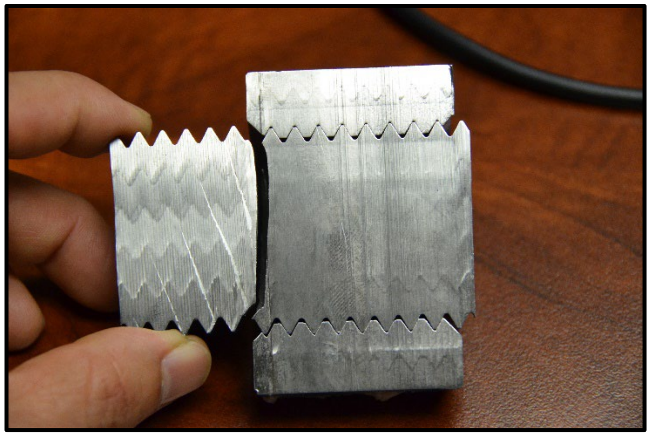

Figure 11: MPFM Fractured Stud

Critical dimensions were measured, and detailed pictures were taken for nuts 1, 2, 3, and 8 showing the orientation of the studs in relation to the nuts and their placement on the flange. There was no evidence to indicate the nuts backed off during service. Flange face gaps were measured around the MPFM lower flange connection at each stud connection. The flange face gaps were higher by the failed studs (see Figure 12).

Figure 12: MPFM Lower Flange Connection

SES removed insulation from around the upper flange. The gaps between the raised flange face on the MPFM upper flange connection were measured and were reasonably consistent, ranging from 0.228 to 0.250 inches. The flange connections did not exhibit any obvious deformation or bending, therefore indicating the flange was not overloaded.

SES performed continuity tests on each stud and nut in the MPFM lower and upper flange connections with the inlet and outlet pipe cuts. The resistivity measured less than one ohm for all flange connections, indicating a good assembly from the MPFM studs and nuts to the jumper's cathodic protection.

The SES team removed the nuts and studs from the MPFM lower flange connection and recorded the break-out torque values. Although the break-out torque measurements for the lower flange assembly were obtained, the SES investigation report stated that the values should not be used as a reference for extrapolating the associated make-up torque values because half of the MPFM lower flange fastener studs fractured. The ultrasonic stud length measurements were taken before and after the nuts were removed.

SES removed the MPFM from the Blind Tee, visually examined the condition of the mating flanges and the gasket, collected samples, took pictures for records, and stored the remaining nuts. The orientation of the studs on the Blind Tee were marked and recorded and then carefully removed, labeled, and individually stored.

The General Arrangement Drawing specified the installation of a BX 155 ring gasket for both upper and lower MPFM flange connections. The ring gasket that was removed from the lower flange assembly was Type SBX 155. Both gaskets are compatible with BX preps. According to API Spec 17D 2nd edition (Section 7.6.1), type SBX gaskets are vented to prevent pressure lock when connections are made underwater. The SBX gasket was installed at the New Industries facility. The non-conformance was not identified as a contributor to the studs' failure. Some damage was observed on the bevel of the ring gasket; however, the ring gasket damage was not identified as a contributor to the studs' failure. The MPFM lower flange gasket did not show evidence of grease or lubrication, and this complies with the Vx Omni Katmai Interface Drawing.

On September 3, 2020, SES proceeded to remove all the nuts from the top flanges with the orientation marked and stored individually. The upper flange assembly was separated, and the top portion was picked up and laid down for further visual inspection. SES noted the orientation and order of the nuts, studs, and gasket in relation to the flanges. Physical measurements of the studs were taken again for records.

Pre-breakout length measurements for all the studs on the upper flange were taken with a caliper/micrometer and with an ultrasonic length measurement instrument to ensure accuracy. All the nuts on the upper flanges were then un-torqued with the torque machine and the breakout torque values were recorded. After all the nuts were un-torqued, SES measured the unloaded length of all the studs.

According to the SES report, the MPFM upper flange studs did not appear to have been overstressed during make-up. SES's test results revealed the MPFM upper flange studs' average estimated pre-stress values were very close to the assumed value of a stud with SMYS of 120 ksi, but nearly all were significantly below the assumed value of a stud with SMYS of 150 ksi as noted on the MTR for the K1 studs.[16] The variations between a minimum and maximum estimated pre-stress applied to the MPFM upper flange studs was 39.8 ksi. The average length change of the MPFM upper flange studs was approximately 0.029 inches.

[16] 109.5 ksi = 73% of the 150 ksi.

The upper flange showed evidence of a pinkish, brown-colored substance, possibly grease or lubrication used during assembly. There was no significant damage to the flange faces, SBX gasket, or ring grooves of the upper flange.

SES found evidence of counterclockwise torsion applied to the weld neck flange[17] during flange to flange make-up. The upper flange torsion pressed the studs into the sides of the flange bolt/stud holes. Based on all the information found, the BSEE Panel does not believe the upper flange torsion contributed to the jumper failure.

SES examined the studs and found no evidence of mechanical damage or corrosion that would have contributed to the failure. None of the studs indicated evidence of bending deformation. All the studs were found to be consistent with 1-3/4 inch Unified National Coarse (UNC) thread and exhibited a consistent thread pitch of 0.200 inches (5 threads per inch) along their lengths. There was no evidence of thread machining defects. There was no evidence of thread elongation that would indicate the studs were loaded past their yield strengths.

SES inspected the female threads in the Blind Tee. Partial molds were made during the inspection process. SES inspected the molds and found no signs of damage to the Blind Tee female threads.

All nuts, studs, gaskets, and other small parts that were retrieved were transported to the SES Houston laboratory for further analysis. SES conducted multiple examinations, including fractography, metallography, and mechanical testing.

SES performed optical fractography, scanning electron microscopy (SEM), and energy-dispersive X-ray spectroscopy (EDS) examinations of the fractured surfaces of the upper (short) end of studs 1, 2, 3, and 8. All stud failures exhibited a brittle fracture. Figure 13 shows the studs' fracture progression. Macroscopic fracture features show the grain tear pattern to be similar for all four studs. The arrow pointing outward indicates the tear direction during the failure of the stud (see Figure 13). SES could not find a direct correlation between the tear direction and the FEA stress. The seemingly random fracture progression orientations would suggest the stud preload may have been the dominant source of stress.

[17] Weld Neck Flange is fastened to the MPFM outlet upper flange. The MPFM upper flange connection is composed of the Weld Neck Flange (65 ksi SMYS), the MPFM upper flange (120 ksi SMYS), the flange gasket, eight studs (150 ksi SMYS), and 16 nuts (150 ksi SMYS).

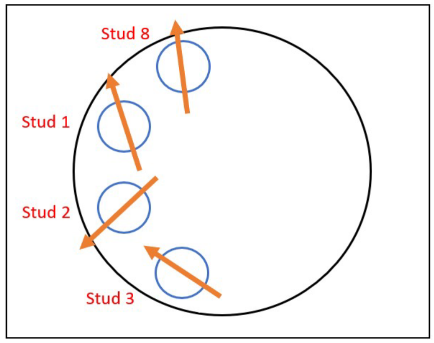

Figure 13: Approximate Stud Tear Direction (Adapted from SES K1 Jumper – Section #2 Investigation Final Report)

Four of the eight studs located on the bottom flange fractured. The fracture occurred at the thread root of the stud at the nut to the flange joint. The failed studs' material microstructure exhibited a fine-grain gamma (γ) phase with delta (δ) phase present at the grain boundary. The presence of the delta (δ) phase renders the material susceptible to cracking due to Hydrogen embrittlement (HE) when used for the subsea environment with cathodic protection.

SES conducted full-scale tensile testing on studs 7 and 12, as well as a K2 stud. Stud 7 was one of the four non-fractured studs previously installed in the K1 MPFM bottom flange connection. Stud 12 was installed in the K1 MPFM upper flange connection. SS7 planned to install the K2 stud in the K2 Jumper's MPFM lower flange; however, the stud was never exposed to the subsea environment.

According to testing by SES, the K2 stud exhibited strength and ductility consistent with its MTR. However, both of the used studs (Stud #7 and Stud #12), which were exposed to the subsea environment similar to that of the failed K1 studs, exhibited poor ductility and failed approximately 24 ksi lower than the K2 stud. In addition, the tensile strength of Studs #7 and #12 were below the minimum specified tensile strength for Alloy N07718 studs in accordance with the ASTM B637 standard. In addition, the total approximate strain at failure (%) was less for Stud #7 and #12 (1.9 and 1.8, respectively) than the K2 stud (7.8).

As noted in the SES investigation report, the load at which the studs failed cannot be considered representative of the load at which the field fractures failed. The field failures would have been under constant loads in a hydrogen-charging environment.

Material characterization testing (mechanical testing, Charpy V-notch (CVN), impact testing, and chemical analysis) was performed on Studs 1 and 11, and on one of the studs designated to be used with the K2 Jumper. The mechanical testing and CVN test specimens were prepared near mid-radius. Mechanical testing was performed per ASTM A370. The sub-scale material characterization testing showed that the material itself was not inherently brittle. As noted in the SES investigation report, "this suggests embrittlement observed in the full-scale tensile testing and field failures was predominantly due to hydrogen exposure, possibly concentrated at the thread roots where it would not have been captured by sub-scale test specimens."

The material characterization testing the microstructural examination, and the Material Test Report (MTR) confirmed the studs were made of Alloy UNS N07718 and heat-treated in accordance with the ASTM B637 standard. The failed studs' material microstructure was fine-grain gamma (γ) phase with delta (δ) phase present at the grain boundary. This microstructure has a known susceptibility to HE when used in a subsea environment under cathodic protection.

Studies have shown the presence of the delta (δ) phase along grain boundaries increases susceptibility to intergranular cracking due to hydrogen. As stated in the SES report, atomic hydrogen is generated on the surface of the cathode (i.e., Alloy 718 material) and diffuses into the material, causing a decrease in ductility. The precise mechanism is not fully understood, but research suggests that hydrogen promotes decohesion of the precipitate/matrix interface.

Hydrogen Embrittlement of Nickel-based Alloy 718 (Inconel 718)

HE, also referred to as hydrogen stress cracking, is a process that can reduce ductility and load-bearing capacity in certain materials and has been observed in offshore environments since the early 2000s. The oilfield has encountered failures with Inconel 718 materials installed in subsea environments with cathodic protection.

The American Petroleum Institute (API) addressed these problems in API Specification 6A718 in 2004. In 2015, API Standard 6ACRA[1] Age-hardened Nickel-based Alloys for Oil and Gas Drilling and Production Equipment superseded API 6A718. API 6ACRA provides requirements for age-hardened nickel-based alloys used in the manufacture of API 6A pressure-containing and pressure-controlling components.

Inconel 718 materials heat treated in accordance with API 6ACRA result in materials with a SMYS of 120 ksi or 140 ksi, while Inconel 718 materials heat treated in accordance with ASTM International B637-18 Standard Specification for Precipitation-Hardening and Cold Worked Nickel Alloy Bars, Forgings, and Forging Stock for Moderate or High-Temperature Service result in materials with SMYS of 150 ksi. B637-18 Standard Specification allows for delta phases in the microstructure which makes the material susceptible to HE when used in a subsea environment and connected to a cathodic protection system.

Inconel 718 materials heat treated in accordance with API 6ACRA (SMYS = 120 ksi or 140 ksi), do not produce delta phases in the microstructure. Inconel 718 materials heat treated in accordance with ASTM International B637-18 Standard Specification (SMYS =150 ksi) produce delta phases in the microstructure that make the material susceptible to HE when used in a subsea environment and connected to a cathodic protection system.

API 6ACRA specifies requirements to prevent HE and other environmental cracking failures. The API 6ACRA standard specifies a higher solution annealing temperature to eliminate the precipitation of delta (δ) phase at grain boundaries.

In August 2014, BSEE released the Quality Control-Failure Incident Team (QC-FIT) Evaluation of Connector and Bolt Failures report in response to a subsea HE bolt failure incident. The investigation revealed the incorrect ASTM B633 specification edition for coating was used.

[1] CRA is "corrosion-resistant alloy."

While the cause of bolt failure was due to HE, the failed bolts were alloy steel, not nickel-based Alloy 718. In 2016, BSEE released an addendum to the QC-FIT report, which further alerted the industry of the effects of hydrogen embrittlement.

As a result of the QC-FIT investigation, BSEE Emerging Technologies Branch (ETB) hosted a Bolt Forum in August 2016 with the industry at the Department of the Interior in Washington, DC. The API bolting committee has since updated the API 20E and released API 20E Edition 2 in Feb. 2017. Some of the details changed in Edition 2 include:

1) The maximum hardness for critical bolting is 40 hardness Rockwell C scale (HRC).
2) Manufacturers of the bolts must record the manufacturing procedure, process parameters, test results, etc., and retain records for ten years (API Q1 specifies five years).
3) API and the industry have set up a database for recording the bolt failures.
4) API 20E Edition 3 is in progress.
5) The API committee also introduced the requirement similarities of API 20E in the API 20F for CRA alloys. The API committee published API 20F Edition 2 in May 2018.

The Inconel 718 studs in this investigation are corrosion-resistant nickel-based alloy and not alloy steel. The material is a CRA and should comply with the materials specification API 20F. When using API 20F material for the subsea application, additional materials microstructural requirements related to CRA materials are defined, and the manufacturing process should be applied accordingly[18].

Heat treatment related to CRA materials is defined in API 6ACRA. The CRA materials should meet API 6ACRA microstructural requirements and the manufacturing process requirements.

In 2017, an OSS Metallurgist published the journal article titled 'Failure Investigation of UNS N07718 (Inconel 718) Bolts under Cathodic Protection for Subsea Oil & Gas Operations.' The article discusses the importance of the API 6ACRA heat treatment standard with regard to fasteners installed subsea with cathodic protection.

Research indicates three conditions must be present for an HE failure to occur (see Figure 14):

1. Hydrogen source environment. Here, the failure occurred in a subsea environment with cathodic protection, which is known to be a hydrogen-source environment.

2. Material susceptible to HE. Here, the fractured studs were made from nickel-based alloy 718 (Inconel 718) and heat-treated according to the ASTM B637 standard. The failed studs' material microstructure was fine-grain gamma (γ) phase with delta (δ) phase present at the grain boundary. This Inconel 718 material microstructure is known to be susceptible to HE.

3. Stress. Here, the normal stress applied during flange assembly is enough stress to initiate HE failure.

[18] API 20F or 6ACRA are not incorporated by reference in BSEE's regulations.

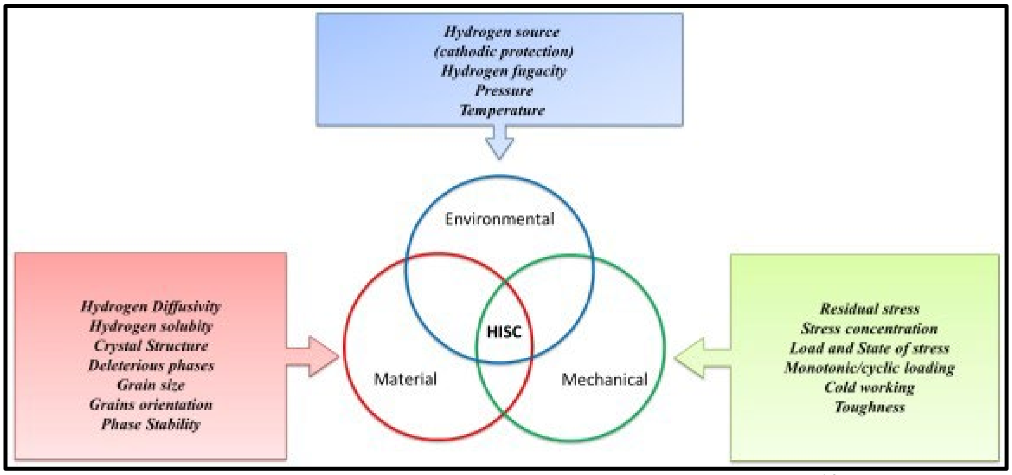

Figure 14: Hydrogen Embrittlement Requirements[19]

Metallurgical key findings:

- The leak in the K1 Jumper was due to the failure of four of the eight fasteners in the flange connection between the Blind Tee and MPFM. SES concluded all four stud fractures were due to HE. "There was no evidence that any damage mechanism other than hydrogen embrittlement contributed to the stud failures."
- The intact fasteners in the flange connections located directly above and below the MPFM were identified as embrittled.
- SES concluded that "[t]here was no evidence of deformation or bending that would suggest that the flanges were overloaded. SES investigation indicates that no evidence of damage was found to the gaskets, ring grooves, and the flange faces that could reasonably be considered the cause of the leak."
- The studs' properties were typical of Alloy N07718 heat-treated in accordance with the ASTM B637 standard, which was consistent with the provided MTRs.

Finite Element Analysis (FEA)

SES conducted an independent design verification assessment of the K1 Jumper Design. According to the SES *FEA Report*, "SES constructed a 3D ABAQUS model of the Katmai K1 Jumper using jumper design inputs, geometry, and allowable stresses/loads. SES then applied various loading conditions such as internal design pressure, external design pressure, thermal flowline expansion, and long-term PLET settlement. These load conditions were applied in different combinations to evaluate the load cases." The five load case analyses were: As-Built, As-Built including LiDAR, As-Built Including LiDAR (No Settlement), As-Leak, and Pressure Spike.

[19] Santos, Dilson & Salvio, Filipe & Silva, Bruno. (2013). On the Role of HISC on Super and Hyper Duplex Stainless Steel Tubes. Proceedings of the Annual Offshore Technology Conference. 1. 10.4043/24289-MS.

SES described the five load cases as follows:

- As-Built load Case: This load case would most closely reflect the analysis likely performed to assess the jumper design of initial installation to verify the design. The purpose of this analysis is to determine if the jumper design was sufficient for the original design conditions.
- As-Built Including LiDAR: This load case is the same as the "as-built" case with the addition of movement readings taken by the provided LiDAR report ahead of jumper removal subsea. The purpose of the analysis is to determine if the jumper design was sufficient for the original design conditions plus additional movements identified by LiDAR scans.
- As-Built Including LiDAR (No Settlement): This load case is the same as the "as-built including LiDAR" case but excluded long term PLET settlement since this likely did not occur in reality. The purpose of this analysis is to determine the effect of the settlement being removed from consideration since it did not occur in reality.
- As-Leak: This load case most closely reflects the stress conditions at the time of failure. The purpose of this analysis is to determine the stresses/ loads at the time of failure.
- Pressure Spike: This load case attempts to re-create the stress conditions at the time of an observed short-term pressure increase at the PLET. The purpose of this analysis is to determine the stresses/ loads at the time of the "Pressure Spike" event that occurred prior to the time of failure.

Four of the five load cases, simulated by SES, resulted in stresses below the design allowable material stress on the jumper. "The As-built Including LiDAR" case was the only load case simulation that resulted in stresses above the design allowable stress. However, this hypothetical load case did not occur. The load case included the jumper basis of design (BOD) long-term PLET settlement value of 15.1 inches. This settlement did not actually occur. When the long-term PLET settlement is removed from the assessment, all calculated stresses/loads fall within acceptable limits.

The Utilization Ratio (UR) compares the calculated stresses (loads) to the allowable design stresses (loads) (see Figure 15). It is important to point out that the allowable design stress (load) is less than the material's yield strength. The yield strength is the stress corresponding to the yield point at which the material begins to deform plastically. The ultimate tensile strength of the material is the maximum stress that a material can withstand while being stretched or pulled before breaking. OSS issued the allowable design stress for the MPFM flange connection.

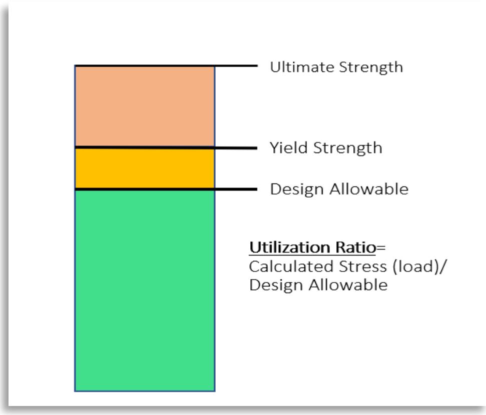

Figure 15: Utilization Ratio (UR)

The two load cases which simulated the max stress load conditions which occurred during the production life of the K1 Jumper before the jumper failure were the "As-leak" and the "Pressure Spike" load case. The analysis of the "As-leak" load case and the "pressure spike" load case indicated the stresses were within acceptable limits. The maximum utilization ratio for both cases occurred at the MPFM lower flange and was 88.76% for the "As-leak" case and 93.4% for the "Pressure Spike" case. In these calculations, the MPFM maximum allowable design stress was provided by OSS and utilized in SES's load case simulations.

The SES report points out "the quoted capacity (Allowable Design Stress) of the MPFM flange (as applied in SES's model) is very conservative when compared to typical flange capacity charts provided in API TR 6AF2." SES calculated the UR values for the two load case scenarios (As-Leak Loading Condition and Pressure Spike Loading Condition) using the MPFM maximum allowable design stress derived from the typical flange capacity charts in API TR 6AF2. The SES calculated UR values occurring at the MPFM lower flange were 38.08% for the "As-leak" case and 40.01% for the "Pressure Spike" case.

The SES FEA Report concluded the K1 Jumper failure was not due to an over-loading scenario.

Flange Torque

The torque applied during the jumper fabrication was not the torque specified in the General Arrangement Drawing. Significant changes in the calculation used to identify that torque included changing the studs SMYS from 120 ksi to 150 ksi and changes to the studs' friction coefficient and the studs' thread form. There was no Management of Change (MOC) process performed for the change.

SS7 generated the General Arrangement Drawing, which prescribed the MPFM flange fastener torque of 3,391 FT-LBS. The document did not show how the torque specification was calculated. Fieldwood's post-incident investigation report indicates SS7 derived the value from averaging three computational methods (Mil-HDBK-60, Shigley, and API 6A) together. The make-up torques were based upon 73% of 120 ksi SMYS; thread form = 8UN; friction coefficient (nut to flange face) = 0.13. This indicated the initial design intent was to install MPFM flange fastener studs with SMYS = 120 ksi.

According to the field technician's torque certification documents, the actual torque applied was 3,120 FT-LBS, not 3,391 FT-LBS. The torque certification document did not show how the torque specification was calculated. Based on the API 6A make-up torque calculation supplied by Fieldwood Projects, it appears as though the generated torque value was based on 73% of 150 ksi SMYS 1-3/4" – 5 UNC threads having a coefficient of friction of 0.07 between threads and nut and flange back face.

There was no MOC performed during this process. This is a significant finding in the investigation because if a MOC was performed the review could have identified the procured studs did not conform with API 6ACRA heat-treatment requirements, the MPFM Interface Drawing's specifications, or initial engineering design intent.

Management of Change

Management of Change (MOC) is a process that OCS operators must develop and implement for modifications associated with equipment, operating procedures, personnel changes, materials, and operating conditions pursuant to 30 CFR 250.1912. All changes must be reviewed before implementation. MOC procedures must include the technical basis for the change; the impact of the change on safety, health, and the coastal and marine environments; the necessary time to implement the change; and management approval for the change.

According to Fieldwood's MOC document,[20] the MOC process ensures that changes to processes and equipment are adequately evaluated by all appropriate personnel, engineering, and management before changes are made. According to the Project Execution Plan, the component participants in SIA would each use their respective management of change processes, but with a mechanism for gaining agreement on any given change. The MOC was of particular importance in this scope, as the SIA was fulfilling the role of Fieldwood in certain respects. The SIA identified a mechanism for managing potential changes, which was agreed to in its alliance agreement.

According to SS7's Workplace Safety Rules, if at any time before work commences or during its execution there is a requirement to change, in any way, from an approved procedure, then the MOC process must be followed. Responsible personnel are required to stop, risk assess the changed situation, and obtain authorization before work can resume. SS7's Risk Assessment and Management of Change Procedure further describes a process for MOC. This process describes an additional level of assessment by personnel onsite or at a separate location.

As stated in the above section, when making up the jumper and MPFM connection with the Blind Tee, the technician was supposed to follow the make-up torque values on the FAT. However, the documentation provided to the Panel showed that the flange make-up torque values [XXX] did not match the values included in the FAT [XXX].

[20] https://semsportal.fieldwoodenergy.com/Public/Safe%20Work%20Practices/V2%20FWE%20SWP%20B-04%20MOC.pdf

Interviews and discussions with Fieldwood revealed that the MOC process should have occurred under these changed circumstances, to get another level of review to make sure the make-up torque was correct. However, Fieldwood reported that no MOC documentation was found by its investigation team for the difference in make-up torque. Furthermore, the Panel did not receive any documentation indicating that a MOC process had occurred for this change.

Additional Information

Multiple shut-ins occurred during the first several weeks of production for the K1 Well. These shut-ins and subsequent start-ups resulted in the Katmai Flowline experiencing an increased amount of thermal load cycles along with pressure fluctuations. A shut-in event in the early morning of July 24, 2020, resulted in the flowline pressure increasing above 9,400 psi. SES's FEA simulated this high-pressure condition in the 'pressure spike' load case analysis. The SES FEA analysis is summarized in the FEA section.

The Panel requested and received Katmai flowline and K1 Well device data during the life of the K1 Well. The Panel reviewed the operational data received. However, a full review could not be completed due to periods of missing or discrepant data leading up to the incident, as well as on the day of the incident.

The Panel investigated whether there was a correlation between the PLET foundation and the K1 Jumper failure, including the non-uniform sediment under the PLET mudmat to the side of the flange with the four failed studs. The PLET mudmat penetration was less than the design assumed. As a result, a grout remediation procedure was performed that filled the majority of the mudmat voids with cement. The post-grout remediation procedure was formally assessed and approved. The Panel did not find significant evidence to substantiate a correlation since the LiDAR reflected that there was no movement in the PLET mudmat's outer edges.

Further, the Panel reviewed environmental conditions that could have impacted the incident. While a tropical depression was present in the GOM in the days leading up to the incident, Fieldwood reported that it passed within 140 miles due south of the K1 Well. Further, interviews with personnel on the Host Facility did not report any significant impact.

The Panel also investigated whether all the studs failed at one time and if the K1 Jumper could have started leaking before the abrupt pressure decline on July 25, 2020. The Panel noted that the linear pressure decline occurring due to thermal cooling did not have the same slope on every shut-in event. Analysis of the studs did not reveal the order in which the studs failed, nor whether the four broken studs failed at the same time. The Panel also reviewed the K1 Well production data for signs of potential leaks, but as described above, the data was incomplete. The available satellite imagery also did not report any signs of sheening before the abrupt pressure decline on July 25, 2020. While it is possible all four studs did not fail at the same time and/or the breach may have occurred before the abrupt pressure decline, the Panel was unable to reach a conclusion regarding whether a stud failure or a small leak may have existed before July 25, 2020.

Conclusions

Probable Causes

The BSEE National Investigations Handbook defines "probable causes" as those actions, events, or conditions that: a) Would have prevented the incident event from occurring, if corrected; b) Contributed significantly to the incident; and c) Have the most compelling supporting evidence as to both existence of the cause and the degree of its contribution to incident. Accordingly, the Panel identified the following as the probable causes of the incident.

Failure to install *API 6ACRA*-compliant studs in the K1 Jumper MPFM flange connection.

The BSEE Panel concluded that the loss of approximately 479 barrels of oil into the Gulf of Mexico from the Katmai Field Well #1 (K1) Jumper resulted from a failed flange connection between the multiphase flowmeter (MPFM) and Blind Tee. This failure was due to the fracture of four of the eight MPFM lower flange fasteners (or studs) due to Hydrogen embrittlement (HE). The jumper failure likely would have been prevented if API 6ACRA-compliant studs had been installed in the K1 Jumper MPFM flange connection.

A metallurgical investigation conducted by Stress Engineering Services, Inc. (SES) determined the fractures were due to HE. The material characterization testing, the microstructural examination, and the Material Test Reports (MTRs) confirmed that the MPFM flange studs were made of Alloy UNS N07718 and heat-treated in accordance with the ASTM B637 standard. The failed studs' material microstructure was fine-grain gamma (γ) phase with delta (δ) phase present at the grain boundary. This microstructure has a known susceptibility to HE when used in the subsea environment under cathodic protection.

American Petroleum Institute (API) Standard 6ACRA (CRA – corrosion-resistant alloy) Age-hardened Nickel-based Alloys for Oil and Gas Drilling and Production Equipment specifies heat treatment requirements to prevent HE and other environmental cracking failures. The fasteners installed on the K1 Jumper MPFM flange were not in compliance with the API 6ACRA standard and were susceptible to HE when installed in the subsea environment under cathodic protection.

SES's metallurgical evaluation confirmed the three required conditions for Hydrogen Induced Stress Cracking (HISC) were present at the time of the failure: 1) Hydrogen Source Environment, 2) Material susceptible to HE, and 3) Stress. The failure occurred in the subsea environment with cathodic protection, which is known to be a hydrogen-source environment. The fractured studs were fabricated from nickel-based alloy 718 (Inconel 718) and heat-treated in accordance with the ASTM B637 standard, which was known to be susceptible to HE. The MPFM studs were stressed during flange installation and normal production operations. The Panel believes the installation of API 6ACRA-compliant studs at the MPFM and Blind Tee connection likely would have prevented this incident.

Engineering documentation used for procurement did not specify *API 6ACRA* compliance for subsea flange fasteners (studs and nuts).

The Bill of Materials (BOM) used for procuring the K1 Jumper flange fasteners (studs and nuts) was limited to the material description and did not specify the SMYS or heat-treatment standard. Nickel alloy 718 (SMYS=150 ksi) fasteners were procured for the K1 Jumper. The metallurgical heat treatment properties associated with the procured fasteners made them susceptible to HE when installed in the subsea environment with cathodic protection.

OneSubsea (OSS) supplied to Subsea 7 (SS7) the MPFM Interface Drawing which included important MPFM design specifications to be integrated in the K1 Jumper design. The drawing specified for nickel alloy 718 fasteners with SMYS of 120 ksi to be used on the MPFM API flanges. The drawing did not explicitly state that the API 6ACRA heat-treatment standard should be used. However, API 6ACRA is the industry standard for Nickel alloy 718 flange fasteners with SMYS of 120 ksi intended for installation on subsea oil and gas production equipment. The ASTM B637-18 heat-treatment standard does not address a Nickel alloy 718 material with a SMYS = 120 ksi.

SS7 generated the K1 Jumper engineering design and K1 Jumper design drawing (General Arrangement Drawing). The General Arrangement Drawing included the BOM, which was used for procurement of the MPFM flange fasteners. The BOM only included a description of the fasteners and did not include the required SMYS or the heat-treatment requirements.

OSS was not assigned the responsibility of procuring the MPFM flange fasteners. SS7 subcontracted out the responsibility of procuring and installing the MPFM Flange Fasteners to New Industries. To the Panel's knowledge, the General Arrangement Drawing was the only document issued to New Industries with MPFM flange studs and nuts specifications. The studs and nuts were a specialty item and were therefore ordered from a third-party using information listed on the BOM.

The procured studs were fabricated from nickel-based alloy 718 (Inconel 718), heat-treated in accordance with the ASTM B637 standard, and offered a SMYS of 150 ksi. The MTR followed the order and identified the studs to have a higher SMYS than the Interface Drawing specified. The fasteners complied with the BOM specifications and therefore passed the quality control requirements to be installed on the K1 Jumper.

The BSEE Panel believes the incident likely would have been prevented if the engineering documentation issued for procurement specified SMYS=120 ksi and API 6ACRA-compliance for the subsea flange fasteners (studs and nuts). If this information was included in the procurement documents, the Panel believes the correct API 6ACRA-compliant studs would have been ordered.

Gap in the Quality Assurance/Quality Control (QA/QC) process allowed for non-API 6ACRA-compliant subsea flange fastener installation.

The risk of fastener failure due to HE has been well established, especially when installing in the subsea environment with cathodic protection. In 2014, BSEE published a QC-FIT report that identified numerous subsea stud failures caused by HE. The API established heat-treatment standards in API 6ACRA to help mitigate the risks associated with HE and other environmental cracking failures. In 2017, an OSS metallurgist published the journal article "Failure Investigation of UNS N07718 (Inconel 718) Bolts under Cathodic Protection for Subsea Oil and Gas Operations." The article discusses the importance of the API 6ACRA heat-treatment standard with regard to fasteners installed subsea with cathodic protection.

The process summarized in the Inspection and Test Plan (ITP) processes for fabrication included QA/QC checks. However, those checks did not appear to:

1. Explore the lack of SMYS or heat treatment specifications on the BOM.
2. Include a subsea fastener metallurgical evaluation prior to installing the K1 Jumper subsea.

Given the known history of subsea fastener failures due to hydrogen embrittlement, the Panel believes the QA/QC process should have included effective measures to ensure API 6ACRA compliance.

Contributing Cause

The BSEE National Investigations Handbook defines "contributing causes" as those actions, events, or conditions that: a) May have prevented the incident event from occurring if corrected; b) Contributed somewhat to the incident; and c) Have less compelling evidence than the probable causes. The Panel identified the following contributing cause that led to the jumper failure.

Management of Change process not followed.

Management of Change (MOC) is a process for ensuring that modifications to processes and equipment are adequately assessed. When making up the K1 Jumper and MPFM connection with the Blind Tee, the technician was supposed to follow the prescribed make-up torque values on the Factory Acceptance and Testing (FAT) procedure and the General Arrangement Drawing. However, documentation provided to the Panel showed that the actual make-up torque values applied for the studs and bolts did not match the values included in the FAT. The Panel did not receive any documentation indicating a MOC process was performed for this difference.

While the Panel does not believe the specific difference in the torque prescribed and the torque applied to the connection contributed to the incident, the Panel does believe the failure to perform MOC for this modification may have contributed.

Fieldwood's post-incident investigation report indicates the K1 Jumper design's specified flange torque (3,391 FT-LBS) was calculated based on studs with SMYS = 120 ksi, which indicates that the initial engineering design intent was to install studs with SMYS = 120 ksi. The API6A make-up torque calculation supplied by Fieldwood Projects indicates the applied torque calculation was based on fastener studs with SMYS = 150 ksi.

The Panel believes that if a MOC process had been initiated, then the assessment that would have been performed as part of the MOC process would have reviewed the stud specifications, specifically the stud material. This review could have identified that the procured studs did not conform with API 6ACRA heat-treatment requirements, the MPFM Interface Drawing's specifications, or initial engineering design intent. If the non-conformance was identified during the MOC process, this would have likely then led to Fieldwood obtaining the correct studs for the K1 Jumper fabrication.

Other Findings

The Panel also found that at the time of the incident, Fieldwood's methods for immediate subsea leak detection (SSLD) of the K1 Well were limited with the flowline shut-in, inaudible subsea alarms, and seemingly without a CRO monitoring the subsea components in the control room. While this did not contribute to the jumper failure, it could have impacted the timeliness of response to the failure.

In addition, the Panel identified multiple quality control issues that were not identified, resolved, or properly documented prior to the incident. Among others, this included issues with the initial engineering design drawing which specified non-API compliant stud thread form and the misalignment of the MPFM from the manufacturer specifications on the Interface Drawing. Additional issues included evidence of grease or lubrication used during assembly of the MPFM upper flange connection; the MPFM upper flange connection was subjected to counterclockwise torque during assembly; and SBX gaskets were installed at MPFM flange connections instead of the specified BX gaskets.

Recommendations

Recommendations for lessees and operators to consider in order to improve operations and implementation of existing safety and environmental management systems:

- Utilize an industry-knowledgeable metallurgist to evaluate all current and future subsea fasteners to verify fasteners are fit for service and not prone to Hydrogen Embrittlement (HE) or any other environmental cracking failures. For future installations, ensure the metallurgical evaluation is performed during the engineering technical review phase before releasing the engineering design for construction.

- Share Subsea Leak Detection (SSLD) System learnings with industry.

- Emphasize that company, contract, and sub-contract personnel enact MOC when there are modifications associated with equipment, operating procedures, personnel changes, materials, and operating conditions.

- Validate and document flange fastener make-up torque values.

- Ensure SSLD notification system alarms are appropriately set with effective alerts and properly monitored during shut-in, transient, and steady state production operating conditions.

- Consider the subsea leak potential while investigating significant subsea flowline pressure drops even when the pressure trends are above the ambient pressure of the sea.

The Panel encourages industry to develop a standard means for determining shear and torsional capacities of API flange connections.