JNRC - Learning Opportunity Notification (LON) - 009

Incident Details		Incident Impact	
Incident	Varanus Island	People	No direct people impact
Date of Incident	3 June 2008	Environment	Minimal
Location/Country	Varanus Island Gas Processing Plant, WA, Australia	Asset (OPSR advised loss at time of incident)	A$ 60 million
Type of Incident	Fire & Explosion	Reputation	*See Incident Description*
Asset Type	Pipeline		
Asset Status	Operational		
Immediate Cause	Corrosion		
Similar Root Cause Incidents			
Date Updated	11/12/2024		

Incident Description

Varanus Island lies off the coast of Western Australia, about 130 km west of Karratha. The island was developed as an oil and gas processing hub for offshore oil and gas production.

Crude oil is exported via pipeline to a tanker vessel berth. Sales gas is exported to the mainland by a 12" and 16" sub-sea gas pipeline. At the time of the incident, oil and gas processing infrastructure had developed over a number of joint ventures, being the Harriet Joint Venture (HJV), East Spar Joint Venture (ESJV) and John Brookes Joint venture (JBJV). Whilst there were different parties to each JV, there was a dominant partner, who were the Operator and 'responsible person' for all the assets.

In the early afternoon (13h30) a high pressure 12" export gas sales line (SGL), operating since 1992, ruptured and the gas release ignited causing an explosion. The location of the incident was on the beach of Varanus Island in the region of the shore crossing. Almost immediately, an adjacent and parallel 12" high pressure gas inlet pipeline, which was only 226 mm apart from the SGL, also failed. Both pipelines directed intense jet fires towards the main gas processing plant, resulting in further ruptures of a 16" and 6" gas lines within the hour, and finally two 4" lines failed. Fire and debris from the explosion penetrated some 50 m into the gas plant. It was the failure of the two 4" lines that caused most of the plant damage.

The initial explosions created an 8m x 30m crater on the beach to a depth of 2m, exposing pipelines and showered the NNE section of the plant with limestone rocks, stones and concrete coating from the ruptured pipelines.

The ruptures initiated an Emergency Shutdown and 'blow-down' of the plant, and within 20 minutes all 150 personnel on the island had mustered safely with no injuries sustained.

Two crude oil pipelines that ran in the same pipeline corridor remained intact, avoiding a major environmental incident.

Fire water monitors were used to cool vulnerable plant, and attempts made to reduce the pressure in the 12" and 16" ruptured lines.

Critical isolations continued into the afternoon, and as a precaution, staff from some producing assets were also bought to the island.

A 5m elevation difference between the pipelines and process plant area, with an embankment between them, caused the jet fires from the end of the ruptured pipelines to be deflected upwards, limiting the extent of plant damage.

Prevailing wind direction at the time of the incident limited plant damage.

At 17h10, evacuation of non-essential personnel started, with a monitoring crew of 14 remaining. The fire was extinguished by 07h00 on the 4 June 2008.

Consequential loss was significant, noting the Varanus Island facility supplied 30% of WA gas supply, with an estimated A$ 2.6 to 3 billion loss to the WA economy. Gas supply was lost for two months, after which, production returned to around two-thirds of previous production by October 2008, with full restoration taking in excess of a further 12 months.

Whilst there was no direct injury or environmental impact from the incident, it regardless had high potential.

Incident Analysis and Findings (including Causal Factors)

An initial investigation report by the regulator was Issued in October 2008, some 4 months after the incident, and was largely the work of National Offshore Petroleum Safety Authority (NOPSA) under its contract with Department of Industry and Resources (DOIR), and it was the rushed nature of this original investigation that led to the later OPSR Report referenced above.

The Operator conducted their own investigation, although the OPSR report was critical of the delay in the internal investigation and resistance to sharing information with the regulator.

Incident analysis has been based largely around the information provided in the OPSR Report, noting that there was at the time of the report a divergence of opinion between the regulator and Operator as to the root cause, and particularly whether the incident was foreseeable.

It is however broadly accepted from the various investigations conducted into the incident that the initial loss of primary containment was caused by severe external corrosion of the 12" SGL. Where a long section of the pipe in the shore area thinned to a point whereby it was not able to withstand the operating pressure. This rupture directly impacted the adjacent 12" gas inlet pipeline, which then escalated to rupture of the 4 " lines.

Extensive pitting was found along the length of the SGL in the beach crossing area, with general wall thickness reduced at a number of locations, and thinner areas immediately adjacent to the point of failure, with evidence of disbondment of the coating.

The DOIR/NOPSA investigations identified three main causal factors, these being:

- The anti-corrosion coating was deemed ineffective at the beach crossing on the 12" SGL, due to damage and / or disbondment
- The cathodic protection (CP) on the wet-dry transition zone on the beach crossing on the 12" SGL was deemed ineffective.
- The inspection philosophy at the beach crossing and shallow water section of the 12" SGL were ineffective.

The 12" SGL used for the shore crossing had a design pressure of 14.6 MPa and design temperature of 60 deg.C, with specification for a corrosion coating of fusion bonded epoxy (FBE) or asphalt enamel and a metal thickness of 11.1 mm. There was a 3mm corrosion allowance, albeit noting the sales gas was a treated dry gas. Separate design codes were referenced for cathodic protection (CP) for the offshore and onshore portions.

Risk Assessment & Inspection – Operator risk assessments were clear that the point at which the 12" SGL failed was a high risk area for a pipeline, particularly if the coating had become disbonded, creating a region of wet bare metal shielded from CP, which could only be inspected by excavation of field joints or intelligent pigging. Prior to failure of the SGL, the line had not been subject to intelligent pigging, and third party reviews had been critical of the absence of inspection data and inspection scopes for the shore zones, and protection based on the assumption of adequate CP readings and anode wastage data in the subsea section. Whilst the Pipeline Management Plan (PMP) considered barriers such as coating and CP, it did not recognise that a CP system based on subsea sacrificial anodes would not provide consistent protection for a shallow buried pipe in a shore zone subject to variable wetting and drying in sandy soil should the coating fail.

The overly positive risk assessment with respect to the SGP failed to recognise; the poor spacing between some pipelines: no intelligent pigging on a line that had been operational for 15 years; CP ineffective; coatings could or already could have degraded (there was visible evidence of loss of concrete coating on the SGL in 2004); and an isolation valve location did not protect from a shore rupture.

In the second investigation under the OPSR report, the Operator was criticised in respect to integrity management of the pipelines for: little or no effective communication between field technician and management; with multiple warning signs missed, particularly in respect the effectiveness of the CP system in the shore environment; and not reducing the risk of failure at the shore crossing to as low as reasonably (ALARP), noting specifically the absence of IP on the SGL.

Isolation Valves Location - Rupture at the beach crossing meant that even with an emergency shutdown there was 100 km of inventory in the 12" SGP.

Pipeline Spacing – Spacing between the SGP and adjacent 12" gas line was only 226 mm apart, which led to rapid escalation of the incident.

Audit – NOPSA audits had identified shortcomings in Operator audit programmes of critical asset integrity and process safety systems.

Regulation & Responsibility – At the time of the loss, the operations on Varanus Island were regulated through the DOIR. Legislation enacted in 2003, led to the creation of NOPSA, who had responsibility for Commonwealth waters. WA were the last significant justification to mirror the enabling legislation, which meant at the time of the loss, regulatory responsibility for the pipelines rested with DOIR, with NOPSA providing contract technical services, noting given NOPSA and DOIR were both based on Perth, there had been a flight of expertise from DOIR to NOPSA, leaving DOIR both understaffed and lacking in competency. There was a Safety Case regime being applied in WA, albeit "*…grafted onto an already inadequate licensing regime…*". In 2007, a requirement for a PMP was introduced. The OPSR report was critical of the fragmented nature of the regulatory oversight at the Varanus gas plant at the time of the incident, and the competency level which this had been provided, which contributed to the likelihood of incident occurrence. A number of recommendations were made by the OPSR, which are outside of the scope of this LON.

Root Causes

Equipment Failure				Human Performance				Other	
Repeat Failure		Unexpected Failure		Human Engineering		Training		Sabotage	
Preventive/Predictive Maintenance				Procedures	X	Management System	X	Natural Peril	
Design	X			Communications	X	Quality Control	X	Other	
Equipment/Parts Defective				Immediate Supervision					

Lessons Learned

Whilst the available references did not develop specific lessons learned, the below considers some of the consider key areas of focus. These include failures at regulatory, board, Operational Leadership and field level. Such areas of focus should be considered during a risk engineering survey.

Regulatory and Operator Responsibility – it is essential to have clarity of single point coordinating competent regulatory responsibility for offshore safety in each operating region, and that ultimate safety responsibility (duty of care) lies with the Operator, referred to the Duty Holder in some offshore jurisdictions. Be wary of jurisdiction interfaces between onshore and offshore assets that create 'room' for gaps and uncertainty of applicability and set-up to divide logical associated process systems.

Leadership responsibility and Commitment (Process Safety Culture) – A full cycle of integrity management lies across philosophies, execution and assurance processes. Only with an organization that ensures the integrity of all three elements, will the process safety culture improve from a 'calculative' setting to a 'generative' culture.

Inspection philosophy (Shore Crossings) – Attention needs to be paid to developing appropriate schemes of inspection in difficult to access wet/dry soil conditions where CP effectiveness varies, and pipelines more likely in closer proximity ('pipeline corridors') as they approach/leave shore facilities, and often conflicted with environmental requirements. Such crossings should be identified in risk assessment and pipeline management plans, and schemes of inspection established that recognise both the challenges of physical verification and the consequence of loss of containment, which may be significant in view of volume of gas/liquids contained between isolation valves.

Anti-Corrosion Coatings – These form an important part of any pipeline protection system from external corrosion. Quality of application and adhesion at time of manufacture/construction is critical in this regard, as is the way the pipeline is handled during installation, avoiding damage to coatings, with effective final inspection, and as necessary repairs to ensure installed coating integrity. Coatings will however degrade with age and are vulnerable to damage from impact during operational life. Measures should be in place to avoid impact damage, and if possible to monitor coating condition (this is often a challenge as the act of excavation for inspection introduces risk of damage). In the absence of visual inspection, then use of IP (as part of wider inspection) should be mandatory.

Inspection (Results and Findings) – Schemes of Inspection for an offshore environment are typically developed by shore based engineers based on factors such as : materials of construction; known threats; consequence of failure; regulatory requirements; and industry/company/own experience . Actual inspection is then executed by contract technicians under the supervision of an Offshore Inspection co-ordinator. Competence, together with appropriate levels of manning and communication are critical in this circular continuous improvement process.

Cathodic Protection – This is an important risk mitigation factor for pipelines, but is a niche specialist area, with both Operator and Regulator typically lacking in-house experience. Expert advice should be used for system design (optimum not cheapest) and system management, monitoring and result interpretation, and location specific factors must be considered.

References

1. Offshore Petroleum Safety Regulation (OPSR) – Incident Investigation, June 2009