

Localized Pipe Damage in SAGD Steam Distribution Lines

Haixia Guo ; Saravanan Meyyappan ; Basil Perdicakis;
Neil Fricke; Yasin Suzuk; Simon Yuen, Duane Serate

Suncor Energy Inc.
150 6 Ave SW
Calgary, Alberta, T2P 3E3
Canada

ABSTRACT

In Oil Sands SAGD (Steam Assisted Gravity Drainage) operation steam is injected into underground oil sands deposits to heat the bitumen locked in the sand and allow it to flow well enough to be extracted. Depending on the design of the SAGD facility, the steam distribution system can include hundreds of meters or kilometers long of piping/pipeline conveying steam from the plant to the pads. The reliability and integrity of this steam distribution system is critical for SAGD operation. This paper reports significant localized damage found at the high pressure steam distribution system in a SAGD facility. The morphology, distribution and features of the damage and the associated process conditions are summarized. Potential damage mechanisms and contributing factors are analyzed. A damage mechanism similar to conventional FAC (Flow Accelerated Corrosion) but under unique process conditions, i.e. un-conventional FAC with high temperature, high pH, low water quality, and reducing conditions, is deemed to be the most likely corrosion mechanism causing the damage. Further investigation is required to confirm and obtain a better understanding of this damage mechanism.

Key Words: Oil Sands, SAGD, Steam distribution system, un-conventional FAC

INTRODUCTION

In Oil Sands In-Situ operation bitumen is often extracted from underground oil sands deposits through SAGD (Steam Assisted Gravity Drainage) technology. This method involves forcing steam into sub-surface oil sands deposits, usually those at depth greater than 150m (492 ft), to heat the bitumen locked in the sand, allowing it to flow well enough to be extracted [1]. This process technology makes it possible to access the underground deposits otherwise difficult to access through the open mine method. It is particularly relevant in Canada because it is the most common method of in situ extraction used in the oil sands.

The SAGD process requires a large amount of water and energy to create steam and then send steam to the pads to be injected to underground. SAGD facilities above ground typically include water treatment, steam generation (with or without steam separators), and steam distribution piping/pipeline system. Depending on the

© 2022 Association for Materials Protection and Performance (AMPP). All rights reserved. No part of this publication may be reproduced, stored in a retrieval system, or transmitted, in any form or by any means (electronic, mechanical, photocopying, recording, or otherwise) without the prior written permission of AMPP.

Positions and opinions advanced in this work are those of the author(s) and not necessarily those of AMPP. Responsibility for the content of the work lies solely with the author(s).

design of the SAGD facility, the steam distribution system can include hundreds of meters or kilometers long of piping/pipeline. The reliability and integrity of this steam distribution system is critical for SAGD operation.

Given the main purpose of the steam is providing heat to reduce the viscosity of the bitumen, the quality of the steam is typically much lower when compared to that used in electric power plants or nuclear power plants [2].

Recently, localized damage was found at the high pressure (HP) steam distribution pipeline system in a northern Alberta (Canada) SAGD facility after operating for about six years. This paper reports the observed damage on the high pressure steam pipelines. The morphology, distribution and features of the damage and the associated process conditions are summarized. Potential damage mechanisms and contributing factors are analyzed.

DAMAGE OBSERVED

A block diagram as shown in Figure 1 provides a high level overview of the process in the SAGD plant starting from the boilers until the well pads. Depending on the design, some SAGD plants do not have steam separators. The length of the HP steam distribution pipelines can vary from under one hundred meters to several kilometers long. For this northern Alberta SAGD plant, each OTSG (Once Through Steam Generator) and HRSG (Heat Recovery Steam Generator) boiler has a HP steam separator and the CPF (Center Process Facility) boundary is relatively far away from the well pads and thus the total HP steam pipeline is proximately 10 kilometers (6.2 miles) long. The operation conditions in the steam pipeline is 11MPag (1595 psig) and 325 °C (617°F). Detailed process condition is to be discussed in next section.

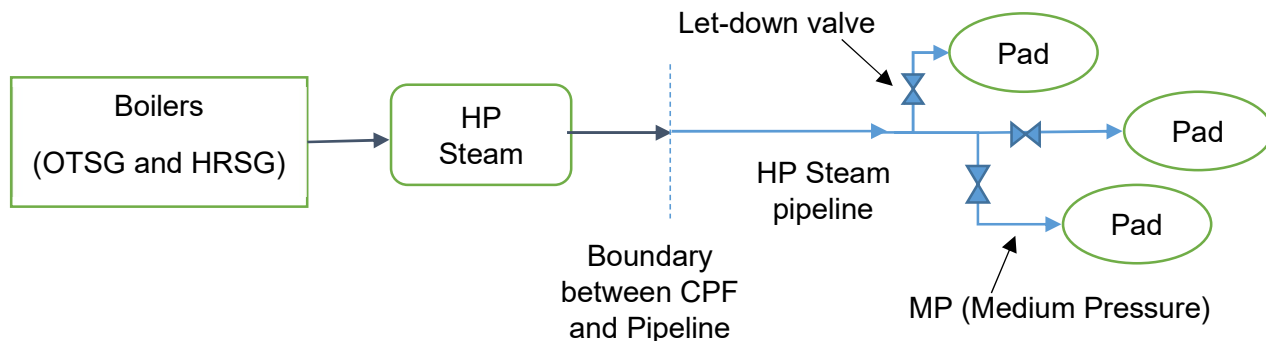


Figure 1: High level overview of the process from the boilers to the pads in the SAGD plant

Except for some material upgrade made at the boilers' outlets, all the piping and the steam separators are made of carbon steel, ASME SA106B and API 5L for the piping sections within CPF boundary and CSA Grade 448 or 550 for the steam pipelines. Carbon steel filler metal is used for the welds. Metal thinning at boiler outlets (boiler external piping) and some sections of HP steam separators have been previously observed and are being monitored and managed by the maintenance programs. The metal loss/ damage in the HP steam lines downstream of the separators, however, is a more recent finding. It covers the plant piping sections within the CPF plant boundary and the CSA pipeline sections conveying steam to the pads. The damage is localized and primarily at the following two types of locations:

- Fittings such as elbows, reducers, tees, and adjoining upstream and downstream pipe sections to a certain length (1-2 ft/0.3-0.6 m).
- Circumferential girth welds and immediate downstream pipe at fitting connections or at straight run pipe sections.

Straight pipe sections further away from the fittings or circumferential welds, do not show any significant damage or thinning, with thickness close to or above nominal thickness. Several NDE techniques such as VT (Visual inspection), RT (Radiographic Testing), UT (Ultrasonic Testing) grid scan, Phased Array UT, have been used to find the damage.

After a thorough inspection of the steam system, it was found that the affected pipe sections or equipment include:

- 1) Inlet piping to HP steam separator from OTSG / HRSG
- 2) HP steam separators – the inlet liquid-vapor separation section and top vapor portion of the vessel
- 3) HP steam piping downstream of the HP Steam Separators connecting to the outlet header
- 4) HP steam header within CPF plant boundary
- 5) HP steam gathering pipeline headers
- 6) Some pad take-off lines up to the let-down valves (Note: take off lines are branch connections from main steam pipelines to individual pads. The process pressure reduces to medium pressure steam after let-down valves.)

Typical damage pictures are detailed in Figure 2 - 5. The damage in the piping sections between the boilers and the HP Steam Separators is shown in Figure 2. As mentioned previously, the damage in this piping section was observed in the past, and material upgrading to 2.25Cr-1Mo low alloy steel has been completed at some locations.

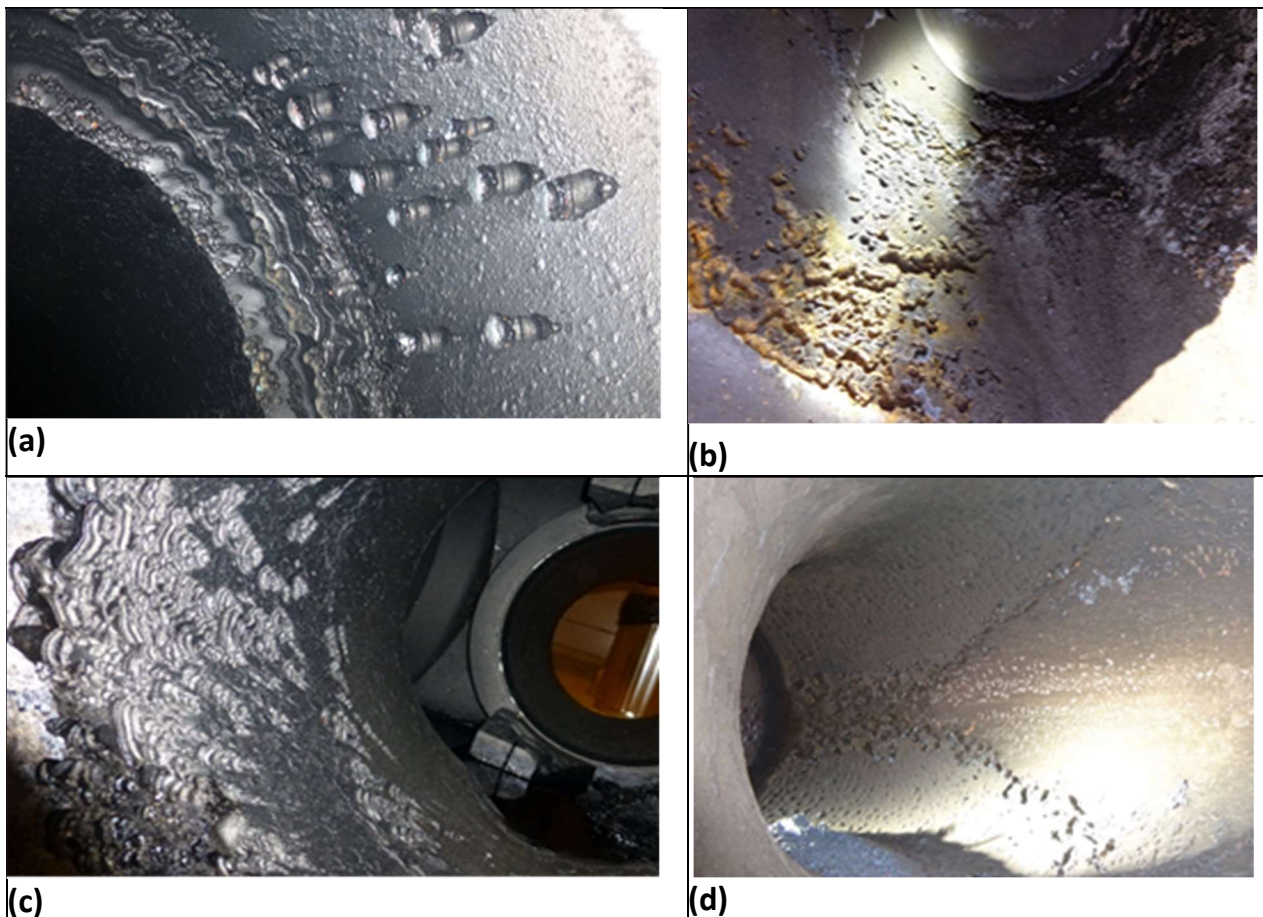


Figure 2: Damage on inlet piping to HP steam separators: (a) Damage found in boiler outlet piping and girth welds connected to gate valve; (b) Damage to stop valves at inlets to HP steam separators; (c) Damage to check valve body; (d) Damage to elbow to steam header

Damage to HP steam separators is found in vessel areas exposed to flow from tangential inlet nozzles where likely the liquid-vapor separation occurs, and also in areas above inlet nozzle of the vessel (vapour portion). The affected internals include the inlet diverter plates, longitudinal and circumferential shell welds (only in vessel portion vertically above inlet nozzles), outlet nozzles, shell welds and vane pack top plates. Damage morphology found is similar to the damage in the inlet piping to separators and the steam headers. Typical damage pictures are shown in Figure 3.

Figure 4 shows the significant damage recently found at the steam lines downstream of the steam separators. Localized, uneven damage are found at fittings, pipe sections adjacent to fittings and some circumferential welds. The estimated highest corrosion is in the range of 30-50 mpy (0.75-1.25 mm/y). Typically for elbows, the damage is more concentrated at the bottom section, i.e. 6 o'clock position, and can go up to 9 or 10 o'clock location at the extrados side. In general the damage is more at the bottom, elbow extrados, and impingement areas of tees and downstream pipe.

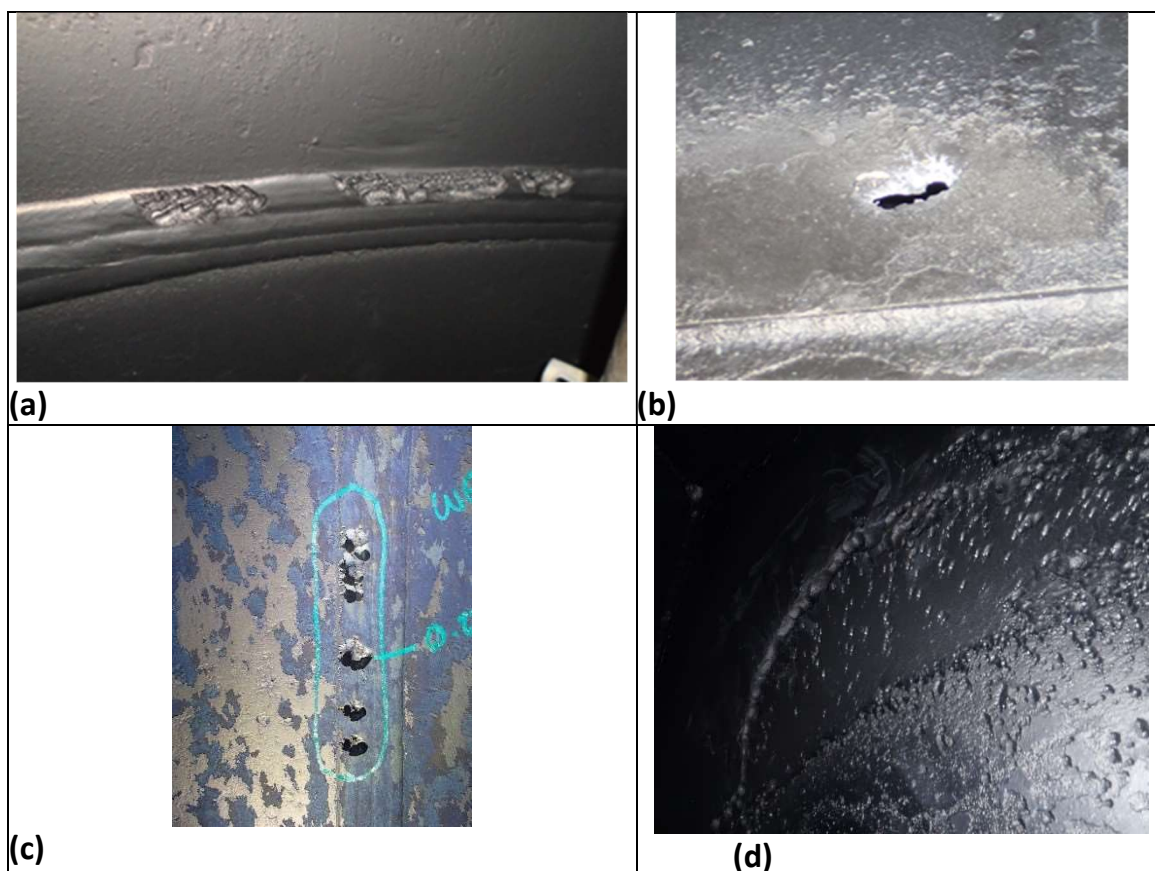


Figure 3: HP steam separators damage pictures: (a) Circumferential weld damage; (b) Hole through on top vane pack plate; (c) Damage to longitudinal weld; (d) Damage to inlet diverter plate.

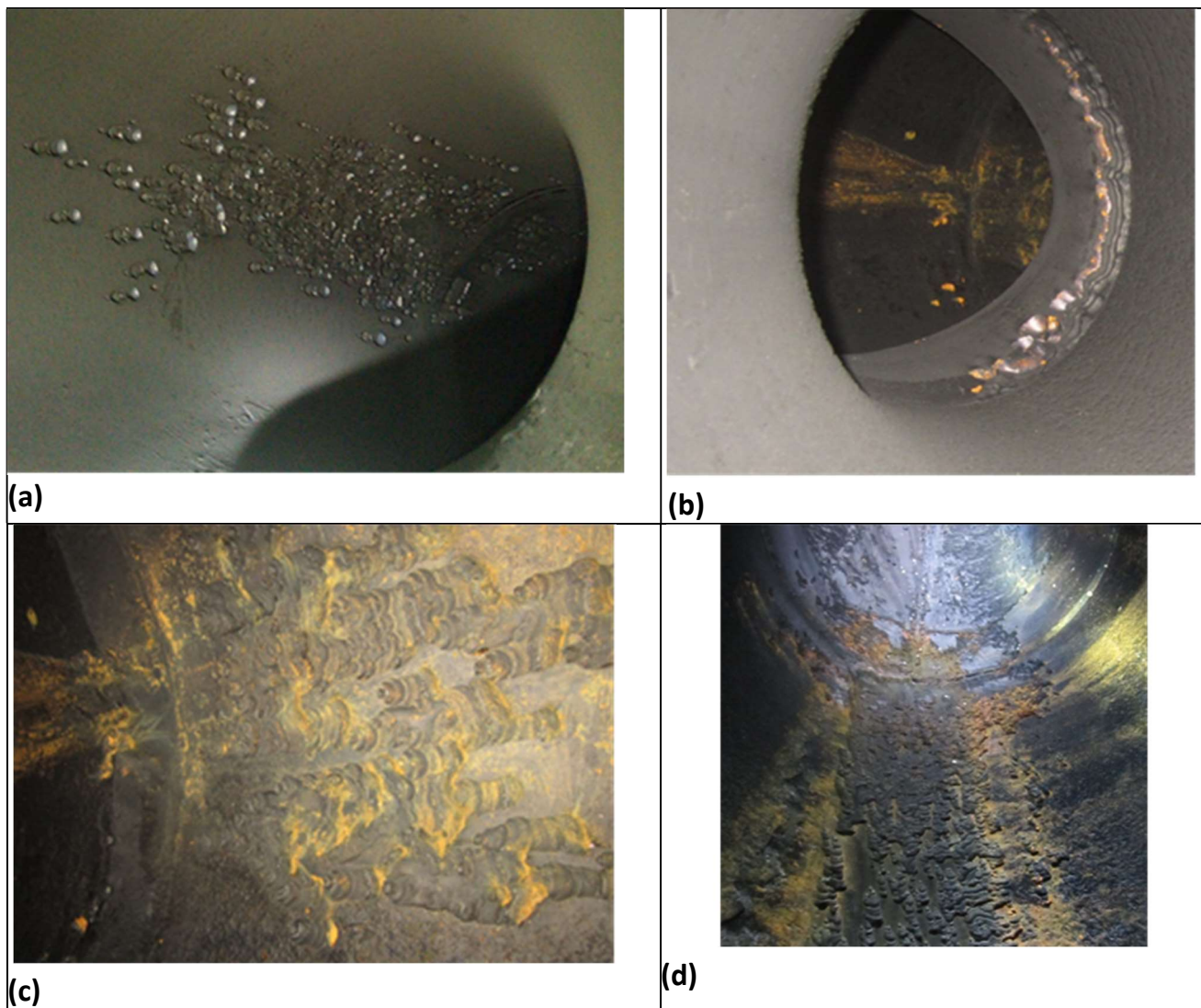


Figure: 4 HP steam separator outlet pictures: (a) Steam separator outlet elbow damage; (b) Circumferential weld damage at steam header tie-in; (c) Pipe damage downstream of a steam tie-in; (d) Vertical elbow and downstream pipe damage

Figure 5 provides a close look of the unique morphology of the localized damage observed at different areas of the HP steam system. A typical pattern of the damaged area consists of wide directional gouges with sharp edges, referred to as “ice cream cones”. The flow direction is typically from the “cone” to the “ice cream top” – this is consistent for most of the damage locations. There are a couple of locations where it seems opposing ice cream cones exist, which is likely related to reverting flow at eddies. In significantly damaged locations the ice cream cones are observed to combine to form extended areas of damage and leave behind undamaged plateaus as shown in Figure 5. Also, the ice cream cones are found to be deeper at the “head” part (downstream end) when compared to the “tail” part (upstream end). The “cone” area contains parallel circular feature – growth rings that appear to increase in size and depth with flow direction. The head of the “ice cream cone” often exhibit “fingerprints” or “ripples”, suggesting of flow-related damage mechanisms.

Figure 6 shows the typical damage at a circumferential weld at pipe bottom section. From the cross section picture it can be clearly seen that the damage occurs at the weld and downstream pipe base metal. The original $\sim 1/8$ (3mm) root weld protrusion has been completely removed. It should be pointed out that some circumferential welds are damaged 360° around the pipe. This is likely related to the flow regime at the location.

Although the damage morphology looks similar in all the sections described, there is variability in affected areas, damage depth etc. at different locations, probably related to different process conditions such as different flow regimes. Overall the observed damage has the following features:

- Damage is localized with uneven distribution.
- Damage is observed at locations of accentuated turbulence, such as elbows, tees, and girth welds.
- Damage occurs in areas where liquid is expected to contact the pipe wall.
- More significant damage is found at pipelines where a higher amount of liquid is expected.
- Damage does not occur at locations with relatively low turbulence level, such as established straight pipe flow.
- Damage does not occur at locations with no flow, such as drain points (no draining in normal operation).
- Damage does not occur in pipelines where liquid amount is low (some 45° take off lines from the top of the main line).
- No significant damage has been found downstream of the pressure let-down valves (Temperature drops from ~325 to ~265°C and pressure drops from 11Mpa to 5Mpa).

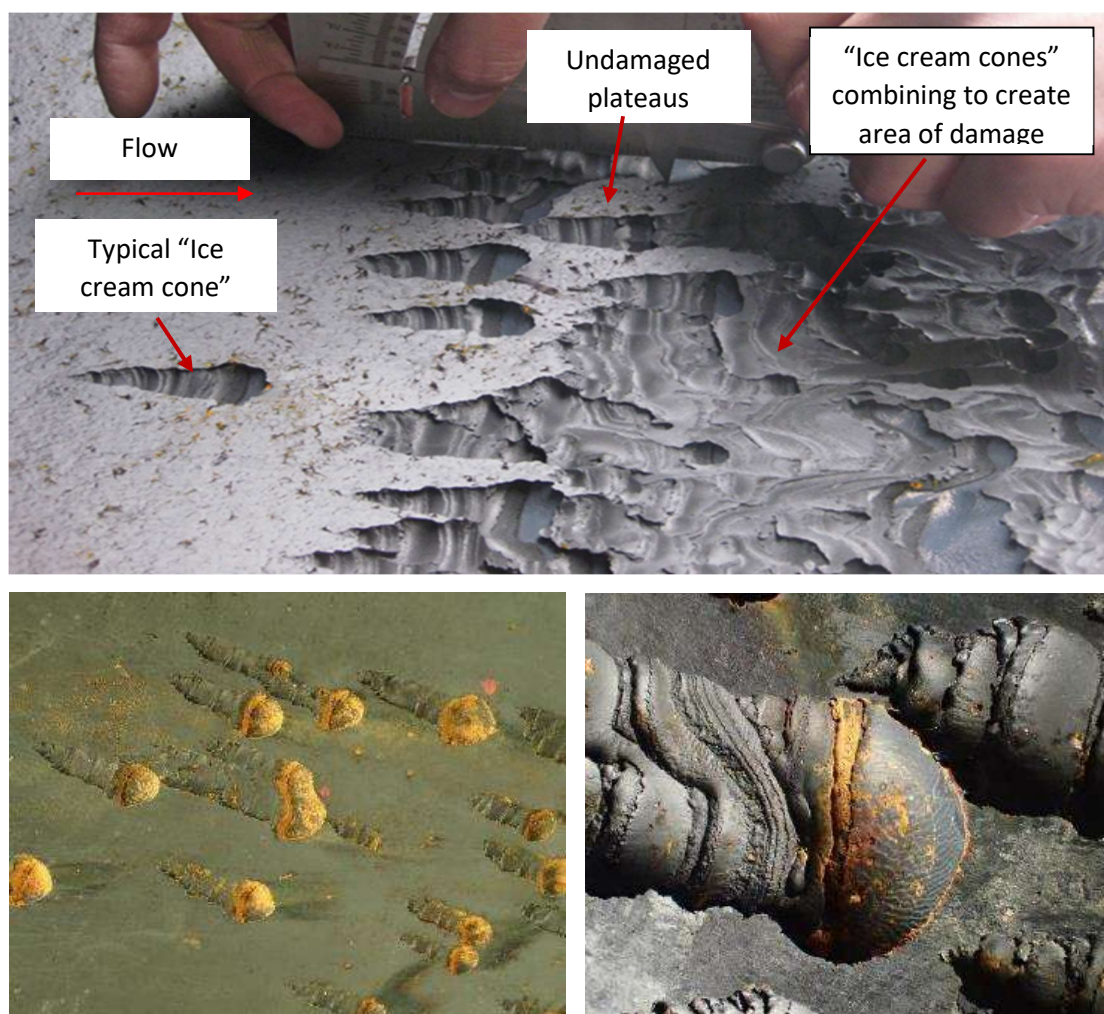


Figure 5: Close look of the damage morphology

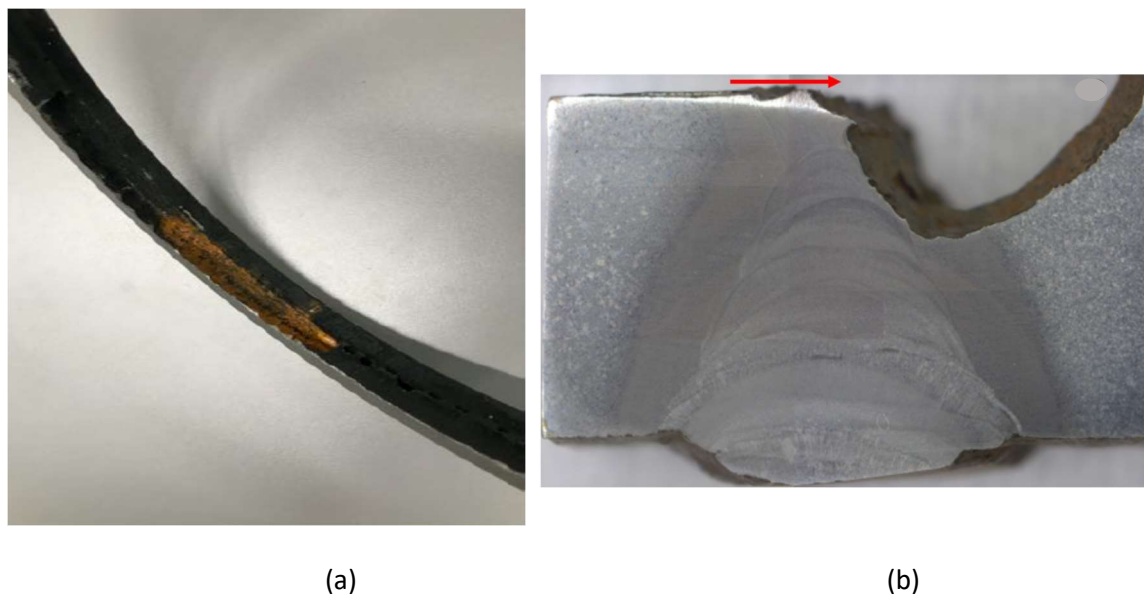


Figure 6: Typical damage at bottom section of a circumferential weld: (a) damage at 6 o'clock position and (b) cross section look

PROCESS CONDITIONS

Table 1 provides a high level summary of the process conditions for the steam system in the SAGD plant. The steam quality at the boilers outlet is limited to 75-80% steam (20-25% blowdown) due to the high mineral content of the boiler feed water (BFW). These mineral impurities in the BFW gets concentrated during boiling in the boiler tubes. Under such condition operating at a higher steam quality will risk significant scaling within the boilers.

Table 1: Process condition of the steam system

Design Temperature	343°C(650°F)
Design Pressure	14.7 MPag (2132 psi)
Operating Temperature	325 °C (617°F)
Operating pressure	11 MPag (1595 psig)
Steam quality at boilers outlet	75-80%
Steam quality at separators outlet	~95%
Steam superficial velocity	21 m/s (69 ft/s) max.

Wet steam from the boilers is separated in the HP steam separators. The separators were designed to achieve an overall separation efficiency of 99.7%, with an efficiency of 100% for droplets larger than 8 microns. However, according to a comprehensive investigation into the HP steam separators design and performance, it is found that a significant percentage of the liquid phase contained in the wet steam is carried over from the HP steam separators into the HP steam distribution system. Representative average steam quality is ~95%, with average liquid carry over at ~5%. Therefore, the flow in the HP steam line is two-phase flow. The presence of blowdown carryover is a key factor in understanding the potential damage mechanisms.

Liquid drainage: