SPE Brazil Flow Assurance Technology Congress
Rio de Janeiro, Brazil, November 06 – 08 2024

Investigating Fail in Downhole Chemical Injection Valves (CIVs) – A Teardown Analysis

João M. F. O. Souza[1], Juliana O. Bahú[2,*], Vanessa C. B. Guersoni[2], Carlos E. Perles[2], Marcelo S. Castro[1,2]
[1]Faculdade de Engenharia Mecânica (FEM), Universidade Estadual de Campinas (UNICAMP), Brazil
[2]Centro de Estudos de Energia e Petróleo (CEPETRO), Universidade Estadual de Campinas (UNICAMP), Brazil.

Abstract
Chemicals have been injected into the downhole of the oil wells in an attempt to ensure efficient production. This measure is a usual oilfield strategy to improve the characteristics of crudes or deal with some flow assurance problems, such as emulsions, scales, paraffin or asphaltenes deposition, etc. To overcome these issues, downhole chemical injection systems (DHCI) have been installed in production facilities, in which the injection of chemicals is controlled by chemical injection valves (CIVs). In this work, it was investigated the possible causes of the failure of four commercial CIVs from demulsifier injection lines installed in heavy oil production systems. The analysis consisted of disassembling the CIVs and analyzing their internal elements, seeking the cause of the failure. A solid material (clogging) was found in some specific parts of the CIVs, which could be the main cause of the CIVs' failure. Solubility tests indicated a polar or apolar characteristic, depending on the CIV. After the analysis, the CIVs were cleaned and reassembled, and tests in a high-pressure line indicated that all of them got back to work properly. These findings have significant implications for diagnosing the root causes of CIV failures in demulsifier injection lines, presenting a procedure to recover obstructed CIVs, and offering preventive measures against future clogging issues.

Keywords
check valves; chemical injection valve (CIV); clogging; demulsifier; downhole chemical injection system (DHCI).

Introduction
Along with the crude oil, other components such as production water and sediments are co-produced and lifted by the same production lines (Krebs and Akdim, 2023). As a consequence, some flow assurance problems may occur along the oil production lines, which include emulsion formation, organic or inorganic scales (Hussein, 2023), etc. Thus, to cope with these common situations in oilfields, injecting chemicals into the downhole is considered one of the most efficient strategies to ensure the minimum flow conditions.
The focus of this work is on the downhole chemical injection (DHCI) system, as it delivers chemicals into the wellbore at a continuous and controlled rate (Daas et al., 2011). The downhole injection of chemicals is specifically important for systems in which the composition of the fluids, associated with changes in pressure and temperature, can severely impact production efficiency. The usual problems found in oilfields are the high viscosity, emulsions, deposition of asphaltenes, waxes, scales, etc. (Guerra and Oliveira, 2014). To deal with the flow assurance challenges, a wide range of chemicals can be injected into the downhole through DHCI systems, enhancing the efficiency of oil production and profitability at various wells (Gilbert et al., 2016; Lagerlef et al., 1995). Demulsifiers can speed up the emulsion phase separation along the lifting lines, reducing the viscosity of the production fluids, and improving the flowability (Vu et al., 2023; Oliveira et al., 2019).
In this way, DHCI systems are of high importance for the good operational condition of the production. Along the injection lines, chemicals are subject to gradients of pressure and temperature, and aging, conditions that can induce precipitation and deposition in the lines and/ or chemical injection valves (CIVs) (Bain, 2013; Stewart-Liddon et al.; 2014a).
The causes of DHCI clogging are: “U-tube” effect, chemical gunking, corrosion, and incompatibility among chemicals eventually put into contact in the injection line. The “U-tube” effect is caused by vacuum cushions that might influence the fluid behavior, as the fluids undergo significant fluctuations in pressure and temperature during injection, which might induce phase transitions of components of the fluid, promoting solid accumulation in CIVs. This vacuum may occur in the chemical injection (CI) line as a consequence of intermittent injections and, also, due to the low

reservoir pressure of mature wells (Rhodes and Welch, 2005).
The gases in the DHCI system can be highly corrosive (galvanic cell), producing corroded metallic particles that can blockage the CIVs and lead to inconsistent delivery of chemicals (Hustad et al., 2012). According to Hustad et al. (2012) and Rhodes and Welch (2005), gases may also form chemical gunking or solid precipitation due to fluid gasification, causing CIV failure. The chemical incompatibility with elements of the DHCI system, such as elastomers, seals, gaskets, etc., might be another cause of clogging (Fleming et al., 2006; Hussein, 2023). The clogging issue is costly for the oil production area since it can require specific cleaning treatments, interrupt the injection process for workover operation, and even cause CIV failure, usually demanding replacement and involving expensive costs (Sandengen et al., 2022; Askari et al., 2021).
In this context, this work aims to investigate the possible reasons for the failure of four commercial CIVs used in DHCIs for demulsifier injection. A teardown analysis was conducted to deeply evaluate the internal parts of the CIVs that could have caused its malfunction by investigating signals of corrosion, damage of internal pieces, degradation of chemicals, and clogging material. This is an up-to-date study in the literature as there are no reports CIVs' failures of downhole injection of demulsifiers injection, besides the teardown inspection of the failed CIVs.

Methodology

Chemical Injection Valves (CIVs)

Four failed CIVs (a, b, c, and d) from DHCI systems for demulsifier injection in heavy oil production lines were investigated. The analysis consisted of disassembling the valves and analyzing the internal components, searching for signals of blocking, corrosion, deposition, etc.

CIVs Teardown

All CIVs were disassembled in seven parts by using a lathe to remove the weld bead connecting them. Afterward, the CIVs were carefully disassembled and the internal elements were removed, looking for damages or solid deposition. It was taken pictures of each element. The pieces were washed with toluene and water, according to the most suitable solvent found by solubility tests of the clogging material.

Tests CIVs after Cleaning and Reassembling

After cleaning the internal components of the CIVs with toluene and water, the valves were reassembled. All the CIVs were tested in a high-pressure system composed of a high-pressure syringe pump (Teledyne Isco, Model 260D) with distilled water as working fluid, as the injected chemical fluid could cause valve plugging. The CIV tests were conducted by increasing the pressure, at room temperature, until the threshold of CIV opening.

Results and Discussion

The CIVs used in this investigation are composed of two high-pressure spring-loaded check valves, one downstream and the other upstream, sequenced in series, maintaining a positive pressure in the CIV even at continuous low flow rates or intermittent injection (Gate Energy, 2023). The upstream check valve, an element to prevent the U-tube effect, has an adjustable spring based on the well depth and downhole pressure (Rhodes and Welch, 2005). The downstream check valve, closer to the wellbore, is stronger than the upstream check valve, acting as a barrier, preventing the CIV from undesired backflow from the well (solids, fluids, or gases) (Rhodes and Welch, 2005). The valve opening occurs in two stages: 1) first, the upstream check valve only compresses its spring if the chemical fluid pressure surpasses the preset spring force plus tubing force. Finally, if the chemical fluid pressure is higher than the wellbore pressure, the valve is lifted off its seat and the downstream check valve opens, allowing the chemical fluid to flow to the well (Schlumberger, 2023 b). Usually, the downstream check valve will open around 10 bars of differential pressure, with Pinj > Pwell, while the upstream valve usually opens close to 250 bars (Hustad et al., 2012).
The teardown analysis started by disassembling the CIVs into seven parts to investigate which and how the internal elements were affected by the solid deposition and, also, identify the main component responsible for the CIV failure. The four commercial CIVs used in the oilfield for demulsifier injection are schematically depicted in Figure 1, as well as their dividing parts obtained in the teardown analysis.

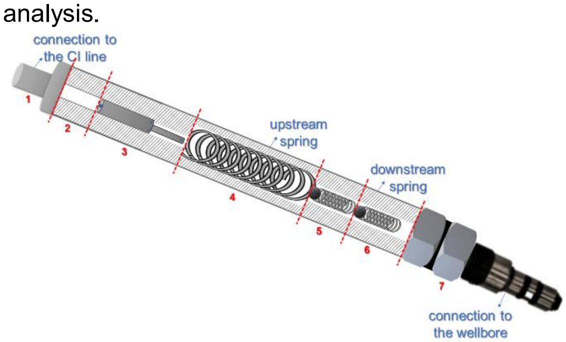

Figure 1. Schematic representation of the CIV from the DHCI lines for demulsifier injection.

Looking at Figure 1, part 1 is connected to the chemical injection line, it has a hollow top connector, which internal thread is connected to the capillary injection line. A valve seat and an injection sleeve compose parts 2 and 3 of the CIVs. Part 4 is a hollow tube that accommodates the upstream coil spring which holds the pre-set working pressure. Part 5 has threads that are connected to the upstream spring and the adjustable housing that is connected to the check spring. Part 6 has flow-through slots that allow the fluid to pass when the ball is off its seat. Part 7 is connected to the wellhead, containing the downstream spring and a lower opening that allows the passage of chemicals to the wellbore.

According to this teardown analysis, by a detailed visual inspection, it was not verified any damage in the internal pieces or even signals of corrosion in the inner parts of the CIVs. Although some solids were found inside the CIVs up to part 3, here named clogging material (Figure 2), some fluids were collected in part 4.

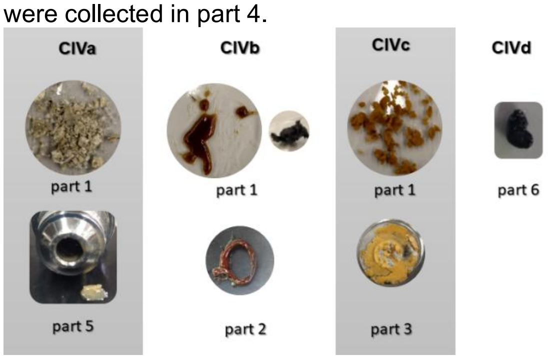

Figure 2. Solids collected in the internal parts of the CIVs.

The clogging material found in the CIVs presented different aspects, the cloggings from CIVa and CIVc are water-soluble, with a grey and brownish color, respectively. CIVa clogging has a dried aspect, while CIVc clogging appears swollen with the fluid injected in the chemical injection line. CIVb and CIVd cloggings (Figure 2) have a brownish to black color, being soluble in toluene, which might indicate their organic nature. Also, CIVb clogging of part 1 and part 2 seems a semi-solid material with high viscosity, whilst the other cloggings are solid.

Initially, there was a hypothesis that the clogging material caused the blockage of the CIV and, consequently, caused its failure. Following this thought, the CIVs internal elements were cleaned with toluene, and water, removing all the clogging material from the CIVs elements. After cleaning, the CIVs were reassembled and submitted to tests of operation in a high-pressure system. The threshold pressure for opening each valve was different: 24 bar (CIVd), 118 bar (CIVc), 150 bar (CIVb), and 206 bar (CIVa). The reason for the different values of operational pressure may be explained by the different pressures of the wells so the spring constant of the check valve was set to match the well pressure.

The analysis of the internal components along the teardown process did not indicate any signs of counter backflow up to 138 bar, whose test occurred with the pump connected to part 7 (oil wellhead). Thus, the backflow is unlikely to be the cause of the cloggings found in the studied CIVs. Although this is a significant finding, the produced water and crude oil in contact with glycol or demulsifier inside the CIV could lead to precipitation by incompatibility under oilfield pressure and temperature conditions (Fleming et al., 2006).

Chemical gunking might occur if there is a low-pressure gas/vapor pocket, volatilizing the fluids and forming a high-viscosity material that can later solidify (Goodwin & Graham, 2018; Stewart-Liddon, et al., 2014b). This is a possibility for the clogging material present at CIVb parts 1 and 2, as it has an organic nature and also a chemically degraded aspect (brown color). This coloration (yellow/brown) also occurs with the fluids found inside the CIVs (part 4) are exposed to high pressure and temperature at the injection point. These degraded products negatively impact oil production as they lose their main function.

If the chemical fluids injected in the CI line were more corrosive under near vacuum (injection condition), the metallic element (Figure 1 – part 7) connected to the wellbore might be more susceptible to corrosion and erosion, processes not visually identified in the CIVs. However, it is essential to evaluate the chemical composition of the clogging material, as some metallic ions could indicate corrosion from another element of the CI system instead of the CIVs.

Another hypothesis for the solids found inside the CIVs is the presence of fine solids that come into the line and accumulate in constrictions inside de valve. The solids could come from fine suspension in the provided demulsifier or even be formed in the storage tanks at the surface facilities. The maintenance of the DHCI free of solid particulates to prevent CIV clogging and consequent failure is crucial.

Conclusions

In this work, four failed CIVs were disassembled with a focus on the identification of the cause of the failure. Inside them, different kinds of materials were collected for further chemical characterization. Based on the teardown analysis, the solid deposits (clogging) found in the CIVs from DHCI system for demulsifier injection may be the main reason for the valve failure, because the solid deposited in capillary channels of one of the internal elements (CIV – part 3), might avoid the fluid passage through the CI line. No other significant damages were found in any of them, so, all CIVs got back to work properly after a careful cleaning process. Two kinds of solids with different chemical characteristics (one organic, and the other inorganic) were found in different valves.

Based on the hypothesis presented in the discussion, the results suggest that continuous improvement and monitoring of the chemical injection system should be carried out to ensure that there are no failures in the process. Some preventive actions include: using an adequate vent in the chemical tank at the offshore platform; periodic cleaning of the chemical tanks to prevent solids accumulation; and use of a filtering system among the chemical injection line.

Acknowledgments

We gratefully acknowledge the support of EPIC – Energy Production Innovation Center, hosted by the University of Campinas (UNICAMP) and sponsored by FAPESP – São Paulo Research Foundation (2017/15736-3, 2022/09052-2, and 2022/00381-3). We acknowledge the support and funding from Equinor Brazil and the support of ANP (Brazil's National Oil, Natural Gas, and Biofuels Agency) through the R&D levy regulation. Acknowledgments are extended to the Center for Energy and Petroleum Studies (CEPETRO-UNICAMP) and the School of Mechanical Engineering (FEM-UNICAMP).

Responsibility Notice

The authors are the only ones responsible for the paper's content.

References

[1] Krebs, T., Akadim, M.R. 2023. Emulsion Separation. Surface Process, Transportation and Storage. P. 779-152. DOI: 10.1016/B978-0-12-823891-2.00003-x.

[2] Hussein, A. 2023. Essentials of Flow Assurance Solids in Oil and Gas Operations. Gulf Professional Publishing. P. 1-1099. DOI: 10.1016/b978-0-323-99118-6.00013-7.

[3] Daas, M.A., Golczynski, T.S., Magalhães, A.A., Bastos, E.C., Ferreira, P.A. 2011. Downhole Chemical Injection through Gas Lift: Options and Consequences. Paper SPE 142951-MS presented at the Brazil Offshore. DOI: 10.2118/142951-ms.

[4] Guerra, L.A., Oliveira, G.H. 2014. Designing Downhole Chemical Injection Systems. Paper SPE 170772-MS presented at the SPE Annual Technical Conference and Exhibition. DOI: 10.2118/170772-ms.

[5] Gilbert, M.L., Morley, D.A., Elliot, P.A. 2016. Application of Subsea Demulsifier Chemicals to Reduce Heavy Oil Emulsion Viscosity and Enhance Production in the Pyrenees Development. Paper SPE 182217-MS presented at the SPE Asia Pacific-Oil & Gas Conference and Exhibition. DOI: 10.2118/182217-ms.

[6] Lagerlef, D.L., Sindelar, S.T., McLelland, W.G., Blumer, D.J. 1995. Downhole Emulsion Breaker Injection into the Lift Gas Stream. Paper SPE 29487 presented at the Production Operations Symposium. DOI: 10.2118/29487-ms.

[7] Vu, H.H., Rangponsumrit, M., Hoang, N.D., Nguyen, D.H., Tran, H.N., Phi, N.N., Roche, T., Dang, V.L. 2023. Identification of Downhole Emulsion in a Light Oil Development and Demulsifier Injection for Increasing Production. Paper IPTC-22754-EA presented at the International Petroleum Technology Conference. DOI: 10.2523/IPTC-22754-ea.

[8] Oliveira, M.C.K., Alevatto, M., Sampaio, T.P., Dias, P.M. 2019. Subsea Demulsifier Injection to Enhance Crude Oil Production in Offshore Brownfields – A Success Case. Paper OTC-29535-MS presented at the Offshore Technology Conference. DOI: 10.4043/29535-ms.

[9] Bain, R. 2013. Putting Pressure on Subsea Pipeline and Umbilical Blockages. Paper SPE 166541presented at SPE Offshore Europe Oil and Gas Conference and Exhibition. DOI: 10.2118/166541-MS.

[10] Stewart-Liddon, C., Goodwin, N.J., Graham, G.M., Tjomsland, T., Hustad, B.M., Svela, O.G., Olsen, J.H., Ostgaard, S. Qualification of Chemicals/Chemical Injection Systems for Downhole Continuous Chemical Injection. 2014. Paper SPE-169782-MS presented at the SPE International Oilfield Scale Conference. DOI: 10.2118/SPE-169782-ms.

[11] Rhodes, R.D., Welch, J.B. Downhole Injection System. 2005. Patent Number US 6.880.639 B2. Available at: https://patentimages.storage.googleapis.com/66/83/a7/3eb65e88d20a18/US6880639.pdf.

[12] Hustad, B.M., Svela, O.G., Olsen, J.H., Ramstad, K., and Tjomsland, T. 2012. Downhole Chemical Injection Lines – Why do They Fail? Experiences, Challenges and Application of New Test Methods. Paper SPE 154967. DOI: 10.2118/154967-ms.

[13] Fleming, N., Ramstad, K., Eriksen, S.H., Moldrheim, E., and Johansen, T.R. 2006. Development and Implementation of a Scale Management Strategy for Oseberg Sor. Paper SPE 100371 presented at the SPE International Oilfield Scale Conference held in Aberdeen, UK. DOI: 10.2118/100371-pa.

[14] Sandengen, K., Ramstad, K., Høiland, S., Henanger, K.E.I. 2022. Should a New Well be Equipped with Downhole Chemical Injection Lines? Paper SPE 209491-MS presented at SPE International Oilfield Scale Conference and Exhibition. DOI: 10.2118/209491-ms.

[15] Askari, M., Aliofkhazraei, M., Jafari, R., Hamghalam, P., Hajizadeh, A. 2021. Downhole Corrosion Inhibitors for Oil and Gas Production – A Review. Applied Surface Science Advances, 6, 100128. DOI: 10.1016/j.apsadv.2021.100128.

[16] Gate Energy. Available at: https://www.gate.energy/marketing-material/bluefin/dciv-8000. Accessed on July 12th, 2023.

[17] Schlumberger – Camco Spring-Loaded Chemical Injection Valves – Retrievable Valves used to Control Chemicals Injected into the Production Fluid at Valve Depth. Available at: https://www.slb.com/-/media/files/al/product-sheet/spring-loaded-chemical-injection-valve.ashx. Accessed on July 4th, 2023.

[18] Goodwin, N., Graham, G. 2018. Evaluating Evaporative Processes – Gas Lift Chemical Applications, Halites and Gunking. Paper SPE 190712-ms presented at the SPE International Oilfield Scale Conference and Exhibition. DOI: 10.2118/190712-ms.

[19] Stewart-Liddon, C., Goodwin, N.J., Graham, G.M., Tjomsland, T., Hustad, B.M., Svela, O.G., Olsen, J.H., Ostgaard, S. Qualification of Downhole Valves Used in Continuous Injection Systems. 2014b. Paper SPE-169783-MS presented at the SPE International Oilfield Scale Conference. DOI: 10.2118/SPE-169783-ms.