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Experiences and Insights Rehabilitating a 69kV SCFF Cable System after Pressure Loss

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SUMMARY

A facility operator in the United States found themselves in a rare situation after they completely lost pressure on a 69kV SCFF feeder that helped power their operation. They had noticed a leak on a trifurcating joint which eventually resulted in the cable system pressure gauge going to zero. Upon further investigation other issues were discovered on the circuit that had to rectified. Once pressure was lost it was unknown whether or not the circuit could be successfully rehabilitated but the operator decided it was worth attempting due to the cost of a replacement circuit.

A number of repairs were completed including performing a new lead wipe on the trifurcating joint and replacing the oil reservoirs. The terminations and trifurcating joint were then vacuum treated prior to filling the cable with new degassed synthetic cable fluid. The three core SCFF cable was flushed numerous times over a period of several weeks. Throughout this process DGA and moisture content tests were performed on fluid samples from the cable to determine when the quality of fluid within the cable had returned to a level suitable for operation. Once an acceptable level had been achieved an Impregnation Coefficient Test was performed to verify the hydraulic integrity of the system. Finally, a 24-hour AC Soak Test was completed before returning the feeder to service.

This paper concludes with best practices for preventative maintenance of SCFF cable systems.

KEYWORDS

SCFF (Self Contained Fluid Filled) Cable, LPOF (Low Pressure Oil Filled) Cable, Oil Reservoirs, Trifurcating Joint, Dissolved Gas Analysis (DGA), Moisture Content, Impregnation Coefficient Test, Oil Degassing

Introduction

In 2021, the operator of an industrial facility in the United States noticed a leak on one of the 69 kV feeders powering their facility. The facility has two feeders for redundancy and the leak was on their backup feeder which left them exposed to the risk of being unable to operate if something were to happen to the main circuit.

Two Self Contained Fluid Filled (SCFF) circuits were installed at the facility in 1988 and the main feeder was replaced with an XLPE circuit seven years ago. The leaking feeder was the original system installed in 1988, which had undergone very little maintenance in the past 10 years due to loss of personnel with SCFF cable systems knowledge. The cable system itself consisted of approximately 700m of cable, three straight joints, two trifurcating joints, three outdoor terminations, three SF6 terminations and two oil reservoirs (see Fig. 1). The cable is a three core 400mm^2 cable with oil impregnated paper insulation, and reinforced 1/2C lead sheath (see Fig. 2). The leak occurred on one of the 69kV trifurcating joints causing DF100 synthetic fluid to collect in the manhole.

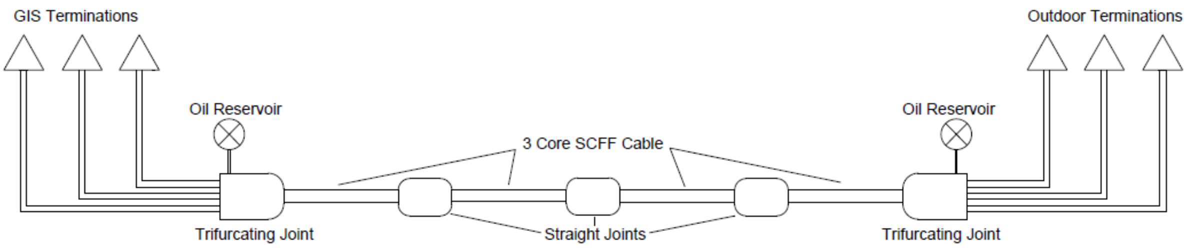

Fig. 1: Single Line Schematic of Circuit

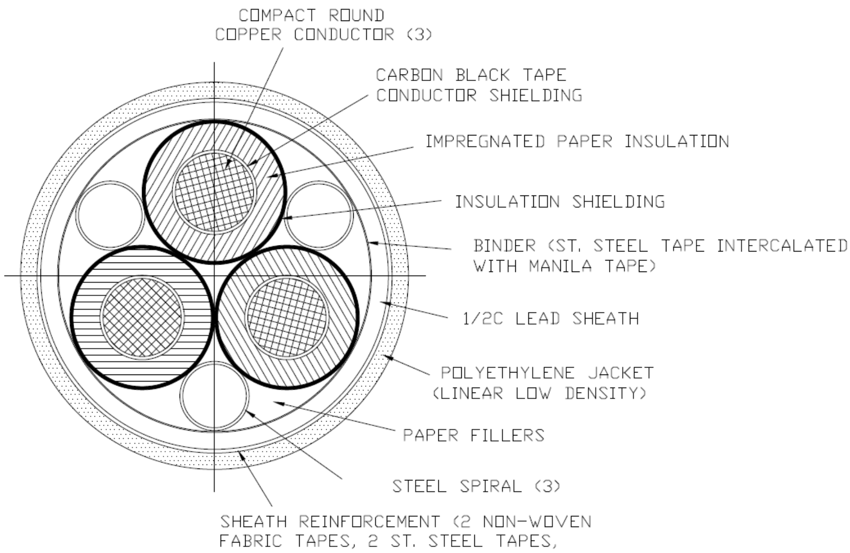

Fig. 2: Typical 3 Core SCFF Cable

The pre-pressurized oil reservoirs ensure that a positive pressure is maintained on the cable system under all operating conditions. Positive pressure must be continuously applied to laminated paper cables to maintain a homogenous insulation in order to supress partial discharges. Laminated insulation is particularly vulnerable to small gaps developing during thermal cycling when a cable heats up and cools down. This facility operator found themselves in a concerning situation because the leak caused the circuit to completely lose pressure. At that point it was not clear whether or not the system could be successfully rehabilitated.

This paper presents the leaks and damage that occurred on the cable circuit, the repair work that was completed to rectify these issues, the process of repressurizing the circuit and ensuring it was still viable, and best practices for maintenance and repair of SCFF cable systems.

Project Overview

An initial inspection of the feeder was performed to investigate the potential to restore the feeder to operation and recommend next steps. The inspection showed that the circuit had been neglected for some time and that there were other accessories in the circuit that needed to be replaced.

One trifurcating joint was leaking in two places (see Fig. 3). The primary leak was at solder wipe between the cable sheath and the joint body. It was also leaking at the connection to the main oil line. The leaks caused the pressure in the circuit to decrease. During initial discussions the facility operator was advised to add more degassed synthetic fluid to maintain a slight positive pressure on the system while not increasing the pressure as that could worsen the leak. When adding degassed synthetic fluid or mineral oil to a system, it is important to use a degasser that is designed for cable fluid. Other degassers may not sufficiently degas the oil and could introduce other contaminants such as PCBs. Fluid filling was not done correctly and the cable system completely lost pressure. At this point, they were advised to immediately take the circuit out of service and then temporarily seal the leaks using plastic cling wrap and multiple layers of SAP and PVC tape (see Fig. 4). Since the pressure had gone to zero, temperature fluctuations could have resulted in a negative pressure which would pull air into the cable. If this were to occur the cable could not be rehabilitated so it was imperative the leaks were sealed.

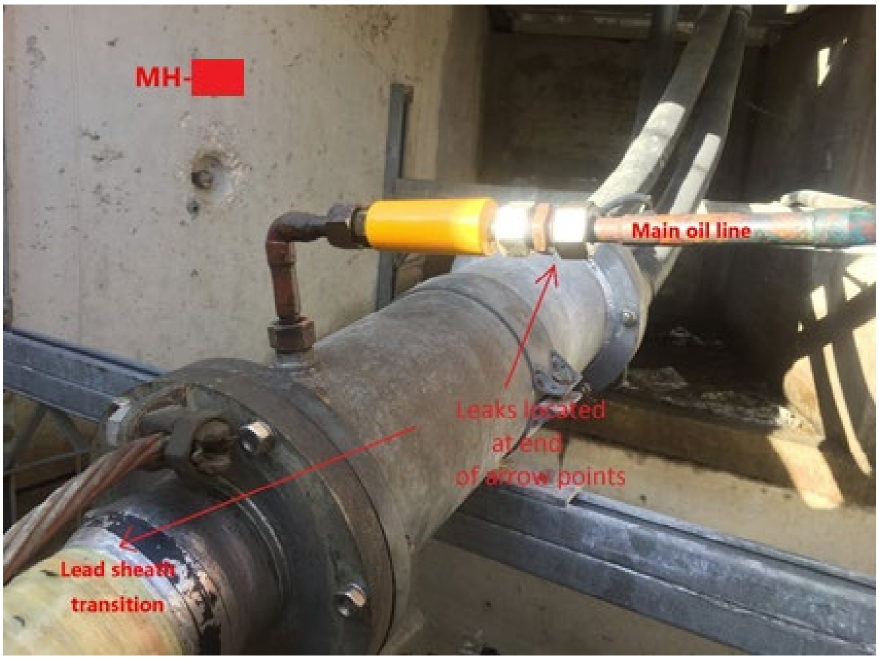

Fig. 3: Leaking Trifurcating Joint

Fig. 4: Leak Sealed with Plastic Cling Wrap and Tape

Upon inspection of the circuit, it became clear that the oil reservoirs at both ends of the circuit would need to replaced. The lids of the reservoirs were not properly sealed which led to the top filling with water and the inner valves and fittings becoming severely corroded (see Fig. 5 and Fig. 6). This level of corrosion did not allow for the necessary connections to be made to re-pressurize the circuit. Also, with the circuit losing pressure and being unable to connect to the corroded fittings, there was no way to verify that the pressurized nitrogen cells inside the reservoirs were still at the correct pressurization level.

Fig. 5 and Fig. 6: Corroded Oil Reservoir Valves and Fittings

Initial dissolved gas analysis (DGA), moisture content and power factor tests were completed on a fluid sample collected from the leaking circuit. A test of PCB content was also completed to ensure the fluid that had been collected was disposed of properly. The moisture content level was measured at 86 ppm (see Table 2) which is well above both the maximum of value 15 ppm specified by most North American utilities and the typical acceptance level of 30 ppm according to IEEE 1406 [1]. The DGA results also showed high levels of oxygen, nitrogen and carbon dioxide (see Table 1) compared to benchmarks in IEEE 1406 [1]. However, it was difficult to collect a representative oil sample due to the lack of pressure on the circuit so there is a chance the sample was contaminated by air. Also, there was not a program in place to monitor dissolved gases in the cable system over time so there was no baseline for comparison. The power factor and PCB content results presented no concerns.

Dissolved Gas	**Test Procedure (units)**	**Test 1**	**Test 2**	**Test 3**
Hydrogen (H2)	ASTM D3612 IEC 60567 (ppm)	0.0	0.5	0.0
Oxygen (02)	ASTM D3612 IEC 60567 (ppm)	17900	<50.0	<50.0
Nitrogen (N2)	ASTM D3612 IEC 60567 (ppm)	53500	13400	11200
Methane (CH4)	ASTM D3612 IEC 60567 (ppm)	1.4	19.0	10.7
Carbon Monoxide (CO)	ASTM D3612 IEC 60567 (ppm)	8.5	20.0	8.2
Ethane (C2H6)	ASTM D3612 IEC 60567 (ppm)	6.2	57.0	21.1
Carbon Dioxide (CO2)	ASTM D3612 IEC 60567 (ppm)	462.0	118.0	22.0
Ethylene (C2H4)	ASTM D3612 IEC 60567 (ppm)	1.0	4.3	0.0
Acetylene (C2H4)	ASTM D3612 IEC 60567 (ppm)	0.0	0.0	0.8
Total Gas	(ppm)	71879	13669	11313

Table 1: Initial DGA Results

Test	**Test Procedure (units)**	**Test 1**	**Test 2**	**Test 3**
Water Content	ASTM D1533 IEC 60814 (ppm)	86	11	4

Table 2: Initial Moisture Content Results

The loss of positive pressure and the high moisture content of the fluid samples were the main concerns when beginning the repair work. As long as positive pressure is maintained on the cable system it is very difficult for air or other contaminants to enter or for separation to occur between paper layers. However, since there was no pressure, it was possible that air had entered through the leak before it was sealed. Alternatively, if the facility operator did not seal the leak properly, air or moisture could have entered prior to the repair work. The long-term neglect of the pressurization system meant that a successful rehabilitation was not guaranteed. If initial efforts did not show improvement, the situation would need to be reassessed to determine whether further efforts would be sensible.

Repair Works

The first step in the repair was to replace the old, damaged oil reservoirs and piping. This ensured that a positive pressure could be maintained on the system after repair of the leak. The reservoirs at both ends were replaced with two new pre-pressurized reservoirs filled with degassed DF100 synthetic fluid (see Fig. 7 and Fig. 8). Fluid from both reservoirs was tested for power factor and moisture content prior to installation. Corroded piping was also replaced.

Fig. 7: New Oil Reservoir – Substation End

Fig. 8: New Oil Reservoir – Outdoor End

Next, the leaking trifurcating joint located at the substation end was repaired. The oil feed was first isolated at the remote end of the circuit so that the feed could then be disconnected from the trifurcator. At this point the fitting that was leaking at the connection to the main oil line was swapped out for a new fitting.

To repair the leak at the solder wipe between the cable sheath and the joint body the trifurcator had to be drained so the lead wipe could be removed. Once the damaged lead wipe was removed the area was prepared for a new wipe to be applied (see Fig. 9). A stick wipe was performed on the leaking area in order to reseal the joint. This involves heating the wipe area with a torch just enough to soften the wiping metal and keep the applied metal malleable. Once the seal was re-established more metal was added to the wipe to reinforce the transitions (see Fig. 10). A stearine-free wiping cloth was used to shape the layers of the wipe and ensure a smooth finish. It is essential to ensure cleanliness throughout this process to achieve a high-quality lead wipe.

Once the lead wipe was complete it had to be tested while the system was under pressure. After the system was re-pressurized a whitewash of talc and alcohol was painted over the lead wipe. Even a very minor leak will clearly show up on the whitewash. No leaks were detected after 24 hours and the wipe was accepted. The talc whitewash was then cleaned off and reinforcing wire was applied adjacent to the wipe for added strength (see Fig. 11). Finally, self-amalgamating and PVC tapes are applied over the reinforced wipe to protect it from corrosion.

Fig. 9: Removal of Existing Lead Wipe

Fig. 10: Application of New Lead Wipe

Fig. 11: Completed Wipe with Reinforcing Wire and New Fitting

Once the oil lines were reattached, the repaired joint was vacuum treated to ensure that no air or other contaminants were in the joint. During vacuum treatment of the joint, the oil reservoir valves were all closed to ensure that excess fluid was not drained from the system. The outdoor terminations as well as the new piping for the oil reservoirs at both ends of the circuit were then vacuum treated to prepare the cable system for the addition of new, degassed synthetic cable fluid (see Fig. 12). For vacuum treating the pressure was brought down to 0.1 and the vacuum was maintained for 3 hours from that point. After three hours the vacuum pump was turned off and an initial reading was taken. After one hour another reading was taken. To pass the vacuum drop test the pressure rise for the hour must be less than 0.1 torr.

Fig. 12: Vacuum Treatment Setup

After vacuum treating, the system was filled with oil under vacuum to ensure all the piping was completely full of fluid and no air was present. Degassed synthetic fluid was fed into the circuit until it began to flow out the other side of the cable to ensure that the entire cable system was full of fluid. A large volume of cable fluid approximately equal to the amount present in the cable's oil ducts was pumped through the system to flush out the old fluid. The valve on the other end was then closed and fluid was added until a pressure of 25 psi was achieved on the system.

After flushing the cable, it was allowed to sit under pressure for at least 24 hours so that fluid mixing could occur between the new degassed fluid in the cable ducts and the older fluid impregnated in the paper insulation. This fluid mixing promotes the migration of dissolved gases before performing DGA or moisture content testing. If time is not permitted to allow for newly degassed fluid to be mixed within the cable system, sampling will provide optimistic results reflecting the condition of the new fluid and not the condition of the cable system. Also, by allowing more dissolved gases to mix with the free fluid in the ducts, as cable flushing is repeated concentrations of dissolved gas in the cable system will be reduced.

After 24 hours, a fluid sample was taken for DGA and moisture content testing. Compared to the initial test, DGA and moisture content levels improved significantly, with moisture content decreasing from 86 ppm to 11 ppm and the levels for oxygen and hydrogen dropping to acceptable levels. Nitrogen was the only gas still at an elevated level (see Table 1 and Table 2).

To further improve the quality of cable fluid in the system the cable was flushed several more times over the following week and then retested after holding the circuit under pressure for 48 hours. This resulted in another considerable improvement in the test results. Moisture content further reduced to 4 ppm (see Table 2). The nitrogen concentration was still high; however, this is not unusual in older cables (see Table 1). Since the oxygen level is so low it shows that the high nitrogen is not a result of air contamination which would be problematic. In this case, it is likely due to residue from the manufacturing process that has remained inside the cable insulation and core fillers. This is one reason it is important to perform DGA routinely so that the values can be compared to a base level.

Verification Tests

Several tests were performed to determine whether the cable could be restored to service. The initial tests completed were the DGA as per ASTM D3612 and moisture content as per ASTM D1533. After the third DGA and moisture content tests, the levels met the acceptance criteria in IEEE Std 1406 [1] (see Table 3). The only exception to this was the nitrogen concentration as previously noted.

Table 11—Guidelines for levels of gases found by DGA in SCFF cable systems (ppm by volume)

	Gas	Normal, age in years			Moderate concern	Severe concern
		< 5	5–20	> 20		
Nitrogen	N_2	50	75	100	> 300	> 500
Oxygen	O_2	25	50	70	> 100	> 300
C. dioxide	CO_2	20	50	75	> 150	> 300
C. monoxide	CO	10	20	50	> 100	> 200
Hydrogen	H_2	50	75	100	> 200	> 400
Methane	CH_4	5	15	30	> 50	> 100
Ethane	C_2H_6	10	20	40	> 75	> 150
Ethylene	C_2H_4	0	5	10	> 25	> 75
Acetylene	C_2H_2	0	0	0	> 10	> 25
	TCG	50	100	200	> 400	> 800

Table 3: Table 11 from IEEE Std 1406 Section 12.1 [1]

Next the Impregnation Coefficient Test was performed to confirm the hydraulic integrity of the cable. This test identifies free air trapped in the system as well as any fluid leaks that are present. To complete the test a known volume of oil is withdrawn and the corresponding drop in pressure is measured [2][3].

$$K = \frac{\Delta V}{V}\frac{1}{\Delta P}$$

Where ΔV = Volume of oil withdrawn (l)
ΔP = Drop in pressure (bar)
V = Volume of oil in installation (l)

Fig. 13: Impregnation Coefficient Formula [2]

The impregnation coefficient (K) as calculated based on the formula in Fig. 13 must be less than $4.5\text{x}10^{-4}$ bar^{-1}. This test was performed on the repaired cable system. Withdrawing 100 mL of oil led to a drop in pressure of 33 kPa resulting in a K value of $1.42\text{x}10^{-4}$ bar^{-1} which is well below the maximum value. Based on the repairs completed and the tests conducted the cable was determined to be successfully rehabilitated as there was no longer elevated levels of air, gases or moisture in the cable system.

One potential issue performing the Impregnation Coefficient Test is determining the volume of oil in the installation. Many times, with old cable installation such as this one, most of the records have been lost or destroyed. As a result, information such as the oil volume in the system may not be available as was the case for this project. The oil volume can be estimated using the cable cross section and the length of the circuit, if known. In this case the area of the oil ducts and the length were used to estimate the amount of free fluid. The same was done for the volume of oil impregnated in the paper except that it is assumed oil occupies 50% of the volume of the paper insulation and paper fillers. Finally, comparable commercially available SCFF joints and terminations were used to estimate the volume of fluid in the accessories.

After completing the DGA, moisture content and impregnation coefficient tests, the cable fluid was flushed a few more times to further improve the quality of the cable fluid. The final test performed before re-energizing the circuit was a 24-Hour AC Soak Test. The cable system was energized to its rated voltage for a period of 24 hours under no load and monitored to ensure that no faults or breakdowns were present. The system passed the test and the feeder was returned to service.

Typically, a DC Hipot test is recommended to test the electrical insulation of the system. DC Hipot testing is common practice for both SCFF and HPFF cable systems [4]. In this case, the AC Soak Test was used upon request of the facility operator.

Best Practices

<u>Preventive</u>

SCFF cable systems are extremely reliable with proper care and routine maintenance. Some SCFF cable installations have been in service for 80-90 years and continue to operate. One issue that utilities and private companies have with these cable systems is that the knowledge of how to maintain them has been lost as the industry transitioned to extruded cable systems. However, by completing two inexpensive tests on a regular basis many issues can be quickly identified and resolved to ensure the cable remains in good operating condition.

The first recommended test is a jacket test on the cable. One of the primary concerns with these cables is the potential for leaks as was the case for the system described in this paper. The primary cause of cable leaks on fluid filled cables is corrosion of the sheath. This usually occurs because the cable jacket has been damaged exposing the metallic sheath to moisture. Over time the sheath corrodes eventually to the point where fluid is able to escape. Performing routine jacket testing and fault locating ensures that any damage to the cable jacket is quickly identified and can be repaired before a leak occurs. Ideally, a jacket test would be performed every year and definitely should be done at least every 3-5 years. It is also good practice to perform a visual inspection of the circuit quarterly to help identify any leaks, damage or corrosion, such as what was seen on the oil reservoirs.

The second recommended test is an analysis of the cable fluid for dissolved gases and moisture content. It is imperative that the cable fluid samples are taken correctly by someone who has prior experience. If sampling is done incorrectly, it could cause severe damage to the cable system. Completing yearly DGA and moisture content testing allows a baseline to be established. This way anomalies can be detected and investigated to determine their cause. High DGA values may indicate that electrical or thermal stressors have been applied to the cable system. Evaluation of results and trends by a subject matter expert is recommended.

These tests are quick and inexpensive to perform and will identify most potential concerns before they become a more serious and expensive problem. However, once an issue is detected it is imperative that it is dealt with in a timely manner. For example, in this case the leak was not repaired soon enough and it could have caused the entire cable system to fail and need replacement. It is also important to replace problematic cable accessories such as joints and terminations proactively before a catastrophic failure occurs.

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