Power Transformer Condition Management Program for Oil and Gas Industrial Facilities

Hamad Tuaimi
Consulting Services Department
Saudi Aramco
Dhahran, Saudi Arabia
hamad.tuaimi@aramco.com

Ibrahim Alkadi
Consulting Services Department
Saudi Aramco
Dhahran, Saudi Arabia
ibrahim.alkadi@aramco.com

Mufarreh Algahtani
Consulting Services Department
Saudi Aramco
Dhahran, Saudi Arabia
mufarreh.algahtani@aramco.com

***Abstract*—This paper presents the lessons learned and challenges faced during the development and implementation of a transformer condition assessment program at a large oil and gas company. A methodology was developed to identify the condition of large power transformers that are due for replacement or have a risk of failure and require immediate action to rectify. This was achieved by a rational application of assessment criteria and ranking mechanisms. The transformer condition assessment program helps to minimize capital expenditures by using cost-effective alternatives that will extend the economic life of a power transformer. This paper focuses on evaluating aged power transformers (over 20 years old) through an advanced assessment program, which mainly consists of a two-level criteria scoring system. This will allow proactive action of flagging end of life, expediting mitigations, monitoring, and reporting the state of critical power transformers, which can be implemented on conservator type oil-immersed power transformers. A case study is also presented in this paper.**

Keywords—power transformer condition management, advanced assessment program, two-level criteria

I. Introduction

Transformers reliability is crucial and their continuous operation is a desire for all power providers and consumers. Engineers at world-class companies are currently facing the challenge of assessing the condition of aged power transformers that were installed and on duty for more than 20 years. From experience in the oil and gas industry, power transformers are able to operate for more than 40 years especially when they are lightly loaded through double ended switchgear. The advantage of this configuration is to distribute the loads into two feeders that in order will increase power system availability and maintain operation continuity. Power transformers are like any other equipment, it degrades overtime. This is a normal behavior for all type of equipment and the process of this phenomenon for power transformer based on its mechanical strength and the integrity of its insulation system. Kraft paper, pressboard, and mineral oil are the main insulation media in oil-immersed power transformers.

Periodic preventive maintenance and recently developed online monitoring systems are valuable methods to maintain and evaluate the condition of power transformers. Nevertheless, these methods do not take into consideration the analysis of all transformer's parameters and do not present the actual condition of the entire transformer. For this reason, an advanced condition assessment program was developed with high quality condition management system to assess the condition of aged power transformers with high level and detailed assessment results.

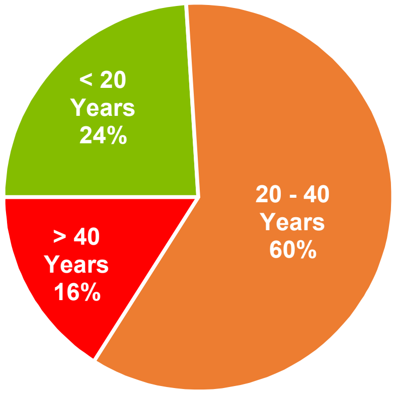

Fig.1. Company's power transformers distribution by age

The most relevant oil and gas facilities were surveyed to consolidate aged and on duty critical power transformers for this program. Fig. 1 represents distribution of transformers by the age of a selected fleet of power transformers with a power range from 20 to 100 MVA and primary voltages 69 to 230 kV. The criticality of a power transformer is based on its failure consequences, which would constitute a safety hazard, facility outage, or catastrophic power interruption. The transformer fleet was categorized based on criticality key factors where a transformer is serving as 1) a main-entrance transformer serving as coupling point between electrical utility network and oil/gas operating plant, 2) a generator step-up transformer as defined by IEEE Std C57.116, 3) a captive transformer feeding a critical motor greater than 7,500 hp, 4) a transformer feeding critical single-ended substation, or 5) a transformer feeding central control room.

The first large-scale assessment of large power transformers at a middle-east oil and gas corporation was completed in 2008. The assessment included eight gas plant main-entrance transformers at a primary voltage of 230 kV and power rating from 90 to 100 MVA manufactured in 1977. The objective of this study, refer to Fig. 2, was to assess the residual life of those transformers feeding a major facility and develop a strategy to ensure a safe and reliable power supply to a major gas plant. As a result, the study identified low probability of failures and a remaining transformer life of 10 to 15 years. This outcome was based on a deterministic criteria utilizing a manufacturer database heavily involved in the condition assessment of power transformers worldwide.

978-1-7281-0653-3/19/$31.00 ©2019 IEEE

In 2014, a cross-departmental team was organized to measure and report on the state of all critical and aging power transformers. The team's goals were to ensure a more reliable electrical system for all aging transformers through analyzing results of major preventive maintenance or electrical faults. The team identified the need to provide a transformer condition assessment program (TCAP) to rank and prioritize aging transformer projects. As a result, an engineering procedure was issued in 2014 [14], including the criteria for governing the identification of transformers at higher risk of failure, a ranking mechanism to assist in planning for their replacement or overhauling, and the development of a program to manage aging large transformers.

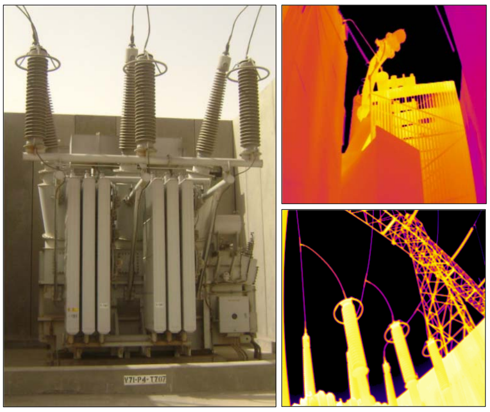

Fig. 2. Part of the first transformers assessment visual inspection and thermography of 230 kV primary to 13.8 kV secondary; 100 MVA feeding a major gas plant

Over the last five years, periodic updates of the TCAP have been carried out, which now encompass hundreds of large and critical power transformers companywide. Additionally, transformer diagnostics guidelines [15] were developed.

II. TRANSFORMER CONDITION ASSESSMENT PROGRAM

The Transformer Condition Assessment Program (TCAP) assisted in reducing major transformer failures and facilitate the continued availability of a safe and reliable power supply. The program consists of the following components:

- Collecting transformer information through site surveys and from previous preventive maintenance records.
- Developing a database to serve in evaluating, scoring, and reporting the condition of critical transformers.
- Applying two-level criteria for identified aged transformers by utilizing advanced scoring system.
- Establishing technical recommendation reports on the status of transformers highlighting specific areas of risks and concerns.
- Developing a short- and long-term strategy based on business opportunities for migration, upgrading, and replacement.

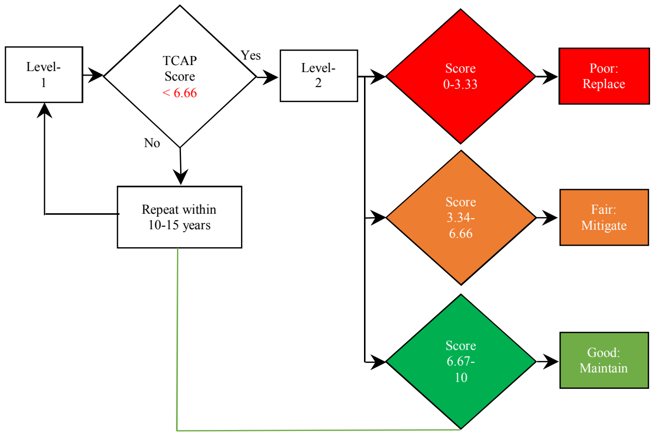

Fig. 3. TCAP level-1 and level-2 scoring system

III. WEIGHTING AND SCORING METHODOLOGY

The condition assessment criteria consists of two levels that cover all transformer condition parameters. Criteria that are at or below the threshold value will be flagged. These measurements provide in-depth indication for the condition of the power transformers and estimation for the remaining lifetime.

Level-1 condition assessment is considered as screening level required to determine the need for more in-depth analysis, namely: level-2 assessment and scoring. The screening level-1 consists of four major components: 1) oil screening test analysis, 2) review of operation and maintenance history, 3) oil dissolved gas analysis, and 4) degree of polymerization. If the weighted sum of the criterions is less than 6.66 (out of 10), then more analysis throughout level-2 assessment is required. Fig. 3 depicts the TCAP scoring system. As listed in Table I, the major components in level-1 and level-2 assessments are from criterion 1.1 to 2.9 and have 0 to 3 scores, with 0 being the lowest score. The score is based on weighting factors (WF) derived from international standards acceptance criteria for all mentioned tests, for example IEC 60599 [2] and IEEE C57.104 [4] for Dissolved Gas Analysis Test (DGA). It is worth mentioning that the degree of polymerization (DP) in level-1 has the highest weighting factor, since it represents the tensile strength of transformer's paper insulation. Kraft paper is an irreversible process and, once the DP value goes below the acceptable value (less than 800), the transformer will degrade more than expected. DP is measured indirectly from the furan compounds dissolved in the oil.

TABLE I. TRANSFORMER MANAGEMENT CRITERIA AND SCORING PROCEDURE

	Criterion	WF	Score
Level-1			
1.1	Oil Screening Test Analysis	0.91	(0 - 3)
1.2	Oil DGA	0.61	(0 - 3)
1.3	Operation and Maintenance History	0.31	(0 - 3)
1.4	DP	1.50	(0 - 3)
Level-2			

2.1	Turns Ratio Test	0.37	(0 - 3)
2.2	Short Circuit Impedance Test	0.37	(0 - 3)
2.3	Winding DC Resistance Measurement	0.37	(0 - 3)
2.4	Frequency Response Analysis (FRA)	0.37	(0 - 3)
2.5	Excitation Current Test	0.37	(0 - 3)
2.6	Winding Power Factor	0.37	(0 - 3)
2.7	Winding Capacitance	0.37	(0 - 3)
2.8	Bushing Power Factor	0.37	(0 - 3)
2.9	Bushing Capacitance	0.37	(0 - 3)

The weighted sum of the first four criterions under level-1 assessment will indicate any abnormal conditions when score is less than 6.66. This score can be improved with standard corrective maintenance solutions or will flag major concerns that require additional investigation and analysis through level-2 assessment. Table II describes the suggested course of actions as a result of level-1 and level-2 assessment. Also, it estimates the remaining life of the transformer that is based on field experience on power transformers.

TABLE II. RECOMMENDED COURSE OF ACTION FOR EACH SCORE RANGE

Score Range	Suggested Course of Actions		Remaining Lifetime Estimation (Years)
	Based on Level-1 Score	Based on Final Score	
0-3.33 ***Poor***	Conduct Level 2 testing.	– Develop short- and long-term O&M plan. – Begin replacement / major repair process.	0 to 5
3.34-6.66 ***Fair***	Conduct Level 2 testing.	– Develop short- and long-term O&M plan. – Repeat assessment per team recommendation.	5 to 10
6.67-10 ***Good***	Continue O&M without restriction.	– Repeat assessment per team recommendation.	10 to 15

Level-2 condition assessment requires the transformer to be taken out of service to perform the needed tests mentioned in Table II. The final score is the aggregate of 40% of level-1 score, plus 60% of level-2 score.

The transformer team built an initial database of power transformers. All selected transformers went through level-1 assessment and 15 units were de-energized for the detailed level-2 assessment. Accordingly, the team developed refined weighting factors for criterions and sub-criterions. The technique considers additional multiplication factors to reflect more accurate scores. Those factors were derived based on experience and benchmark with international standards, guidelines, and manufacturing databases.

Table III describes the scoring methodology of the oil screening criterion with additional multiplication factors as follows:

- If interfacial tension (IFT) score is 0; then, divide aggregate criterion score by 2, if score is 1; then, divide aggregate criterion score by 1.5.
- If acid score is 0; then, divide aggregate criterion score by 2, if score is 1; then, divide aggregate criterion score by 1.5.
- If moisture in paper score is 0; then, divide aggregate criterion score by 1.5, if score is 1; then, divide aggregate criterion score by 1.25.

TABLE III. OIL SCREENING SCORING

Criterion 1.1: Oil Screening Test Analysis	Range	Score	WF
Dielectric Strength (Disk electrodes-gap 2.5 mm)	0 – 24.9	0	0.1
	25 - 27.5	1	
	27.6 - 29.5	2	
	≥ 29.6	3	
Interfacial Tension (IFT)	0 – 27.9	0	0.155
	28 - 29.4	1	
	29.5 – 31.9	2	
	≥ 32	3	
Acid Number	0 - 0.05	3	0.2
	0.06 - 0.084	2	
	0.085 - 0.15	1	
	0.16 - 1	0	
Oil Power Factor (at 25C)	0 – 0.09	3	0.1
	0.1 – 0.2	2	
	0.21 – 0.3	1	
	0.31 - 10	0	
Moisture in Oil (corrected at 20C)	0 - 9.9	3	0.07
	10 – 19.9	2	
	20 – 25.9	1	
	≥ 26	0	
Moisture in Paper (%M/DW)	0 – 1.25	3	0.08
	1.26 – 2.0	2	
	2.01 – 2.50	1	
	2.51 - 10	0	
Corrosive Sulfur Indices	1	0	0.2
	0	3	
Color	3.51 - 100	0	0.045
	0 - 3.5	3	
Quality Index	0 - 1500	0	0.05
	1501 - 10000	3	

Table IV describes the scoring methodology of the Oil DGA with additional multiplication factors as follows:

- If H2 scored condition is 0; then, divide aggregate criterion score by 2.0, if scored condition is 1.0; then, divide aggregate criterion score by 1.5.

- If CH4 scored condition is 0; then, divide aggregate criterion score by 2.0, if scored condition 1.0; then, divide aggregate criterion score by 1.5.
- If C2H2 scored condition is 0; then, divide aggregate criterion score by 3.0, if scored condition is 1.0; then, divide aggregate criterion score by 2.0.
- If C2H4 scored condition is 0; then, divide aggregate criterion score by 2.0, if scored condition is 1.0; then, divide aggregate criterion score by 1.5.
- If C2H6 scored condition is 0; then, divide aggregate criterion score by 2.0, if scored condition is 1.0; then, divide aggregate criterion score by 1.5.
- If CO scored condition is 0; then, divide aggregate criterion score by 2.0, if the scored condition is 1.0; then, divide aggregate criterion score by 1.5.
- If TDCG scored condition is 0; then, divide aggregate criterion score by 2.0, if scored condition is 1.0; then, divide aggregate criterion score by 1.5.

TABLE IV. DGA SCORING

Criterion 1.2: Oil DGA	Range	Score	WF
Hydrogen (H2)	0 - 100	3	0.200
	101 - 700	2	
	701 - 1800	1	
	≥ 1801	0	
Methane (CH4)	0 - 120	3	0.017
	121 - 400	2	
	401 - 1000	1	
	≥ 1001	0	
Acetylene (C2H2)	0 – 1.9	3	0.500
	2 – 9.9	2	
	10 – 35.9	1	
	≥ 36	0	
Ethylene (C2H4)	0 - 50	3	0.017
	51 - 100	2	
	101 - 200	1	
	≥ 201	0	
Ethane (C2H6)	0 – 65.9	3	0.017
	66 - 100	2	
	101 - 150	1	
	≥ 151	0	
Carbon Monoxide (CO)	0 - 350	3	0.017
	351 - 570	2	
	571 - 1400	1	
	≥ 1401	0	
Total Dissolved Combustible Gases (TDCG)	0 - 720	3	0.200
	721 - 1920	2	
	1921 - 4630	1	
	≥ 4631	0	
Carbon Dioxide (CO2)	0 - 2500	3	0.017
	2501 - 4000	2	
	4001 - 10000	1	
	≥ 10001	0	
CO2/CO Ratio	0 – 2.9	0	0.017
	3 – 4.9	1	
	5 – 7.4	2	
	≥ 7.5	3	

The scoring methodology of the operation and maintenance history criterion 1.3 differs as it is based on facility's maintenance checklists and practices. The most common items that require careful attention are 1) tap changer, 2) bushings, 3) cooling system, 4) transformer loading history, 5) monitoring devices, 6) control cabinets and accessories, 7) surge arrestors, and 8) oil containment and fire barriers.

Table V describes the scoring methodology of the DP.

TABLE V. DP SCORING

Criterion 1.4: DP	Range	Score
DP value	0 - 359	0
	360 - 599	1
	600 - 799	2
	≥ 800	3

The score of the turns-ratio test criterion 2.1 consists of only two scores. The score is 3 as the highest score when the difference from nameplate V1/V2 is less than 0.5%. The lowest score is 0 when at any tap; the difference from nameplate V1/V2 is greater than 0.5%.

The score of the short circuit impedance test criterion 2.2 consists of four scores. The score is 3 as the highest score when the difference from nameplate impedance is less than 1%. The score is 2 when the difference from nameplate impedance is 1% to 3% (minor degradation). The score is 1 when the difference from nameplate impedance is 3% to 5% (significant degradation). The score is 0 as the lowest score when the difference from nameplate impedance is greater than 5% (severe degradation).

The score of the winding DC resistance measurement criterion 2.3 consists of four scores. The score is 3 as the highest score when there are no anomalies. The score is 2 when anomalies are present (any reading more than 5% deviation) and in the same time number of on-load tap changer operations between 1 to 2 times the recommended by the assessed transformer's manufacturer and improvement pattern detected. The score is 1 when anomalies are present (any reading more than 5%) and number of tap operations above 2 times the recommended by the assessed transformer's manufacturer and improvement detected. The score is 0 as the lowest score when anomalies are present (any reading more than 5%) and no pattern improvement detected.

The score of the FRA criterion 2.4 consists of only two scores. FRA is only used as an assessment tool of an aged transformer if there is a fingerprint available from a previous test, or factory acceptance test. The score is 3 as the highest score when FRA measurements are in accordance with fingerprints. The lowest score is 0 when anomalies are detected with previous fingerprints.

The score of the excitation current test criterion 2.5 consists of only two scores. The score is 3 as the highest score when the difference between two higher currents is less than 10% for excitation current less than 50 mA, or the difference between two higher currents is less than 5% for excitation current greater than 50 mA. The lowest score is 0 when the difference between two higher currents is greater than 10% for excitation current less than 50 mA, or the difference between two higher currents is greater than 5% for excitation current greater than 50 mA.

The score of the winding power factor criterion 2.6 consists of four scores. The score is 3 as the highest score when the power factor is below 0.5%. The score is 2 when the power factor is in between 0.5% to 0.6%. The score is 1 when the power factor is in between 0.6% to 0.7%. The score is 0 as the lowest score when the power factor is above 0.7%.

The score of the winding capacitance criterion 2.7 consists of four scores. The score is 3 as the highest score when the capacitance reading is less than 3% from fingerprint. The score is 2 when the capacitance reading between 3% to less than 5% from fingerprint. The score is 1 when the capacitance reading is in between 5 to less than or equal 8% from fingerprint. The score is 0 as the lowest score when the capacitance reading is above 8% from fingerprint.

The score of the bushing power factor criterion 2.8 consists of four scores. The score is 3 as the highest score when the power factor is less than 0.5%. The score is 2 when the power factor is in between 0.5% to 0.65%. The score is 1 when the power factor is in between 0.66% to 0.8%. The score is 0 as the lowest score when the power factor is above 8%.

The score of the bushing capacitance criterion 2.9 consists of four scores. The score is 3 as the highest score when the capacitance reading is less than 5% from the nameplate. The score is 2 when the capacitance reading is in between 5% to less than 8% from nameplate. The score is 1 when the capacitance reading is in between 8 to less than or equal 10% from nameplate. The score is 0 as the lowest score when the capacitance reading is above 10% from nameplate.

IV. CASE STUDY DISCUSSION

The established TCAP criteria was performed on oil and gas facilities critical power transformers. Out of the selected transformers, 15 scored poor (less than 3) during level-1 assessment and were recommended for off-line level-2 assessment. One critical power transformer scored (1.46) during level-1 assessment per Table VI. That transformer manufactured in 1984 and rated 20 MVA, 34.5/4.16 kV, Dyn1 during Level-1 assessment per table IV.

TABLE VI. OUTCOME OF LEVEL-1 ASSESSMENT

Indicator	Indicator	TCA (0 to 3)	WF	Score
1.1	Oil Screening	0.72	0.91	0.65
1.2	O&M History	2.23	0.31	0.69
1.3	DGA	0.19	0.31	0.11
1.4	DP	0	1.50	0
Total Level 1 Condition Index (Between 0 to 10)				1.46

This outcome was a result of high level of hydrogen, ethylene, ethane and methane gases, which indicate overheating fault. Source of the fault could be a spot overheating in the core due to flux concentrations, overheating of copper conductor from eddy currents, bad connection on winding to incoming lead, or bad contacts on tap changer. Insulating paper is not involved in the problem. The ratio O_2/N_2 indicates consumption of oxygen. Additionally, the DP value was 318, which is below the acceptable value. The team recommended to immediately de-energize the unit and start investigation source of thermal fault using level-2 assessment.

The computed final score is 5.83, which indicates a fair transformer condition. Based on this final assessment score, the team recommended to isolate the transformer and proceed with internal inspection that revealed discovering signs of high temperature marks on the steel wedges between top frame and tank stops as shown in Fig. 4. It was then recommended to install new core insulations to interrupt current circulation loops within the core frames and between core frames and tank. Accordingly, the program had successfully identified a potential major transformer failure and facilitated the continuity of a safe and reliable power supply system.

Fig. 4. Overheating signs on the steel wedges between top frame and tank stops

V. CONCLUSION

This paper provided an overview of the experience and lessons learned in the development and implementation of a well-established TCAP at a large oil and gas company. The application of a scoring and ranking mechanism, along with supporting condition assessment guidelines, have proven to be effective in managing the aging process of critical power transformers. This condition-based approach will be the management tool used to direct, control, and facilitate making life-cycle decisions such as whether to maintain or repair, or to extend the life of the transformers, or to replace them.

The guidelines presented in this paper have been developed to ensure the operability of power transformers and plant reliability, while optimizing expenditures through the TCAP. The management of power transformers is a continuous process. Every year, more transformers enters into the list of criticality, either due to aging for more than 20 years, major preventive maintenance finding, or following an electrical fault. It is recognized that further enhancements to the process are required, including an objective estimation of the power transformers economical end of life. It is recommended that IEEE guidelines be developed highlighting deterministic measurements and specific scoring methodology.

REFERENCES

[1] IEC 60076-18-2012 Power Transformers - Part 18: Measurement of Frequency Response - Edition 1.0

[2] IEC 60599-2015 Mineral Oil-Filled Electrical Equipment in Service - Guidance on the Interpretation of Dissolved and Free Gases Analysis - Edition 3.0

[3] IEC 62535-2008 Insulating Liquids - Test Method for Detection of Potentially Corrosive Sulphur in Used and Unused Insulating Oil - Edition 1.0

[4] IEEE C57.104-2008 Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers

[5] IEEE Std C57.12.00-2015 IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers

[6] IEEE Std C57.12.10-2010 IEEE Standard Requirements for Liquid-Immersed Power Transformers

[7] IEEE Std C57.12.90-2015 IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers

[8] IEEE Std C57.125-2015 IEEE Guide for Failure Investigation, Documentation, Analysis, and Reporting for Power Transformers and Shunt Reactors

[9] IEEE Std C57.139-2015 IEEE Guide for Dissolved Gas Analysis in Transformer Load Tap Changers

[10] IEEE Std C57.140-2006 IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers

[11] IEEE Std C57.143-2012 IEEE Guide for Application for Monitoring Equipment to Liquid-Immersed Transformers and Components

[12] IEEE Std C57.149-2012 IEEE Guide for the Application and Interpretation of Frequency Response Analysis for Oil-Immersed Transformers

[13] IEEE Std C57.637-2015 IEEE Guide for the Reclamation of Mineral Insulating Oil and Criteria for its Use

[14] Management of Power Transformers Procedure, Engineering Procedure SAEP-137, 2017

[15] Transformers Diagnostics best practice document SAPB-P-009, 2009