IGS-C-CH-044-2(0) Sept. 2008

APPROVED

شرکت ملی گازایران - مدیریت پژوهش وفناوری

امورتدوین استانداردها

IGS

Iranian Gas Standards

دستورالعمل اجرائی

بررسی دوره ای کیفیت روغن ترانسفورمرهای برق

Periodic Inspection of Used Insulating Oils in Power Transformers Part 2

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تاریخ : ۱۳۸۷/۸/۲۶
شماره : گ ۰/دب ۰/۵۷۹ - ۱۴۹۴۹

ابلاغ مصوبه هیأت مدیره

مدیر محترم پژوهش و فناوری

باسلام،

به استحضار می رساند در جلسه ۱۳٤۰ مورخ ۱۲/ ۸/ ۱۳۸۷ هیأت مدیره، نامه شماره گ۹/۹۵۷۱٦/۰۰۰ مورخ ۸۷/۷/۳۰ آن مدیریت درمورد تصویب نهایی استانداردها تحت عناوین "روغن ترانسفورمرهای برق" به شماره IGS-M-CH-044-1(0) ، " بررسی دوره ای کیفیت روغن ترانسفورمرهای برق" به شماره IGS-C-CH-044-2(0) و"روش تست کارآیی برای شیرهای سماوری اندازه ۲ تا ۲٤ اینچ" به شماره IGS-M-PL-002(1), Part 1, APPENDIX ارجاعی از سرپرست شرکت مطرح و تصویب شد.

ناصر آبگون
دبیر هیأت مدیره

رونوشت : سرپرست محترم شرکت ملی گاز ایران و قائم مقام رئیس هیأت مدیره
: اعضای محترم هیأت مدیره/ رئیس محترم امور حسابرسی داخلی / رئیس محترم امور حقوقی

۵۷۹

FOREWORD

This code of practice is intended to be mainly used by NIGC and contractors and has been prepared on interpretation recognized standards , technical documents , knowledge , backgrounds and experiences in gas industries at national and international levels .
Iranian gas standards (IGS) are prepared , reviewed and amended by technical standard committees within NIGC Standardization division and submitted to the NIGC's "STANDARDS COUNCIL" for approval .
IGS Standards are subject to revision , amendment or withdrawal , if required , thus the latest edition of IGS shall be checked/inquired by NIGC users .
This code of practice must not be modified or altered by the end users within NIGC and her contractors . Any deviation from normative references and / or well known manufacturers specifications must be reported to Standardization division .
Any comments from concerned parties on NIGC distributed IGS are welcome to technical standards committees and will receive serious attention and consideration should a revision to standards is recommended .

GENERAL DEFINITIONS :

Throughout this code of practice the following definitions , where applicable , should be followed :
1- "STANDARDIZATION DIV." has been organized to deal with all aspects of industrial standards in NIGC . Therefore , all queries for clarification or amendments are requested to be directed to mentioned div.
2- "COMPANY" : refers to national Iranian gas company .
3- "SUPPLIER" : refers to a firm who will supply the service , equipment or material to igs specification whether as the prime producer or manufacturer or a trading firm .
4- "SHALL " : is used where a provision is mandatory .
5- "SHOULD" : is used where a provision is advised only .
6- "MAY" : is used where a provision is completely discretionary .

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CONTENT

1. SCOPE

This code of practice specification provide guidance on the monitoring and maintenance of the quality of the insulating oil in transformers . The purpose of this code of practice is to assist the operator in evaluating the condition of oil in transformers and in maintaining oil in a serviceable condition .
This code of practice specification gives properties ,test methods , warning limits and action for evaluation .

2. REFERENCES

ASTM D 92 (2002) "Test method for flash and fire points by Cleveland open cup tester"

ASTM D 974 (2002) "Test method for acid and base number by color **–** indicator titration"

ASTM D 1524(1999) "Test method for visual examination of used electrical insulating oils of petroleum origin in the field"

ASTM D 1533 (2000) "Test method for water in insulating liquids by coulometric Karl Fischer"

ASTM D 1698 (1997) "Test method for sediments and soluble sludge in service-aged insulating oils"

ASTM D 3612 (2001) "Test method for analysis of gases dissolved in electrical insulating oil by gas chromatography"

ASTM D 5837 (1999) "Test method for furanic compounds in electrical insulating liquids by high-performance liquid chromatography (HPLC)"

BS 2000 : Part 1 (1995) "Methods of test petroleum and its products **–** Part 1 **–** Determination of acidity , neutralization value **–** colour indicator titration method"

BS 5737 (1979) "Method for the measurement of relative permittivity , dielectric dissipation factor and d.c. resistivity of insulating liquids"

BS EN 22719 (1994) "Methods of test for petroleum and its products part 404 : Petroleum products and lubricants **–** determination of flash point **–** Pensky **–** Martens closed cup method"

BS EN 60156 (1996) "Insulating liquid **–** Determination of the breakdown voltage at power frequency **–** Test method (IEC 156 : 1995)"

IEC 814 (1998) "Insulating liquids **–** Oil impregnated paper and pressboard **–** Determination of water by automatic coulometric Karl Fischer titration"

IEC 61198 (1993) "Mineral insulating oils **–** Method for the determination of 2 **–** furfural and related compounds"

IEC 61620 (1998) "Insulating liquids **–** Determination of the dielectric dissipation factor by measurement of the conductance and capacitance"

3. OIL TESTS AND THEIR SIGNIFICANCE

The tests provided in Table 1 are considered to be sufficient to determine whether the oil condition is adequate for continued operation and to suggest the type of corrective action required .

3.1 Color and Appearance

A rapidly increasing or a high color number may be an indication of oil deterioration or contamination .

Besides color , the appearance of oil may show cloudiness or sediments which may indicate the presence of free water , insoluble sludge , dirt or other contamination .

3.2 Odor

If the oil has an acrid or unusual odor , consideration should be given to carrying out further tests . It is useful for comparative evaluation .

3.3 Dielectric Breakdown Voltage

It is a measure of the ability of an oil to withstand electric stress . The measurement of breakdown voltage serves primarily to indicate the presence of contaminants such as water or conducting particles .

3.4 Water

Water may affect the electrical properties of the oil and invariably results in decreased electric strength and resistivity and an increased dielectric dissipation factor .

3.5 Neutralization Value

It is a measure of the acidic constituents or contaminants in the oil . The neutralization value increases as a result of oxidative ageing and as a general guide for determining when an oil should be replace .

3.6 Sediment and Soluble Sludge

The presence of sediment and sludge may change the electrical properties of the oil , and in addition , deposits may hinder heat – exchange , thus encouraging deterioration of the insulating materials .

3.7 Dielectric Dissipation Factor

This parameter is very sensitive to the presence in the oil of soluble polar contaminants , ageing products or colloids . Changes in the levels of the contaminants can be monitored by measurement of this parameter even when contamination is so slight as to be near the limit of chemical detection .

3.8 Dissolved Gases

The levels of dissolved gas and/or changes in these levels can be an indicator of incipient fault condition or air ingress into the oil .

3.9 Flash Point

A low flash point is an indication of the presence of volatile combustible products in the oil .

4. OIL DETERIORATION

4.1 Deterioration

Oil in service is subject to deterioration due to the conditions of use . Oil is in contact with air ,water and contamination that may change the characteristics of oil .
Some changes in the characteristics of oil may indicate deterioration of other materials used in the construction of the equipment . These changes may affect oil materials , and may interfere with the proper functioning of the equipment and shorten its working life .

The contaminants mentioned in the following subclauses may be found in oil in service . The presence of these contaminants or any kind of deterioration of an oil is made evident by one or more changes of the properties discussed in the following subclauses . The development of an odor , and a change in color may be a useful guide to the nature of any contamination or deterioration of the oil .

4.1.1 Air
Oil is in contact with air and therefore subject to oxidation reactions accelerated by an increase in temperature and the presence of catalysts (either metals or dissolved metallic compounds or both) , there may be a change in color , and acidic compounds are among the oxidation products formed . The viscosity may increase and the viscosity index may decrease and foam may form and , at an advanced stage of oxidation , separation of sludge may occur.

4.1.2 Water
Water may originate from the atmosphere or be produced by oxidation of the oil . Its presence is harmful , it may adversely affect the characteristics of the oil .

4.1.3 Solid particles
Insoluble contaminants , including metallic and nonmetallic materials can cause abrasive wear of bearings , pupms , and seal , faulty control functioning , plugged oil lines , and reduce filter life .
Solid particles comprise :
A **–** insoluble oxidation or degradation products of insulating materials ,
B **–** solid products arising from the conditions of service of the equipment : carbon , metal , metallic oxides .
The presence of these particles may reduce the strength of the oil .

4.1.4 Oil soluble compounds
These result from oxidation of the oil itself , or from the solution in the oil of external contaminants or materials used in the construction of equipment . They can be detected and assessed by measurement of acidity .

4.1.5 The acidity
The acid products formed by the oxidation of the oil actively encourage deterioration . It is , therefore , essential to detect and monitor acidity development .
The determination of organic acidity by the measurement of neutralization value is the most convenient and direct method of assessing the chemical ageing of an oil .
A comparison of the rate of change of the neutralization value with that of any of the other characteristics of the oil gives , to some extent , an indication of the probable cause of the deterioration of the oil .

4.1.6 Volatile hydrocarbon
Small amounts of volatile hydrocarbons may be formed during the degradation of oil under the influence of either heat or other stresses , or both . Larger amounts may be an indication of a fault in the equipment . The presence of volatile hydrocarbon deterioration products may be detectable by a lowering of the flash point of the oil .

4.2 Detection

4.2.1 The detection and action to be taken is detailed in Table 1 which gives characteristics , warning limits , test methods and required action if necessary .

4.2.2 The frequency of testing and the action to be taken shall be in accordance with Table 1 . It is advisable to consult with the transformer manufacturer and/or the oil supplier .

5. SAMPLING

Experience indicates that oil is sometimes rejected unjustifiably because inadequate care has been taken in sampling . Careless sampling procedure or contamination in the sample container will lead to erroneous conclusions concerning quality and incur waste of time , effort and expense involved in obtaining , transporting and testing the sample .
The general rules are provided for sampling in ANNEX A .

Table 1 – Requirements for inspection and testing of oil in service

Items	Properties	Units	Warning Limits	Test Methods	Action	Frequency of Tests	Note
1	Odor	---	Not have an acrid or unusual odor .	Examine in a sample container .	If oil not to passes these tests , perform tests 3,4,5 .	All of tests shall be carried out 1 to 2 weeks after filling or refilling and next tests according to results and recommendation of transformer manufacturer.	If the results of each of these tests are close to warning limits , increase frequency of testing .
2	Appearance and color	---	Clear , without visible contamination .	Examine a layer , 100 mm, at room temperature (see clause 4.4) or ASTM D 1524			
3	Flash point	^{0}C	Maximum decrease :15	ASTM D 92 or BS 22719	If oil not to passes each of these tests , perform tests 6,7.		
4	Neutralization value , max	mg KOH/g	0.15	ASTM D 974 or BS 2000 , Part 1			
5	Dielectric dissipation factor at 40 H_Z to 60 H_Z at 90 ^{0}C , max	---	0.5	BS 5737 or IEC 61620			
6	Dielectric breakdown voltage , min	kV	30	BS 60156	Resample and retest , if same , replace oil .		
7	Water , max	ppm	50	ASTM D 1533 Or IEC 814	Determine source and rectify. Resample and retest , if same , replace oil .		
8	Sediments and soluble sludge	%	Consult with transformer manufacturer	ASTM D 1698	According to recommendation of transformer manufacturer		
9	Dissolved gases	ppm		ASTM D 3612			
10	Furanic compounds	ppm		ASTM D 5837 or IEC 61198			

ANNEX A
(NORMATIVE)
" THE SAMPLING "

The following general rules are considered to be the minimum necessary for successful sampling :

– Accomplish by an experienced person .
– Preferably be carried out while the equipment is operating normally .
– Take sample before filtration and centrifuge .
– Not to take sample before or after make up .
– Take sample from specified places . Normally drawn from the sampling valve or the bottom drain valve .
– Take samples preferably in dry weather and avoid any external contamination . If weather is bad , special precautions shall be taken .

Note : every precaution shall be taken when sampling not to contaminate or moisten . Outdoor sampling in rain , fog , snowfall or strong wind shall be permitted only if all precautions have been taken to avoid the pollution . In this special case the use of cover is necessary . Condensation shall be avoided by warming the sampling equipment so as to be above the ambient air temperature

– Ensure that the oil is at least as warm as the ambient temperature (The temperature of the oil at the time of sampling shall be recorded) .
– Use only clean , dry sample containers such as glass bottles (with a polycone screw cap) . Samples should be protected to avoid unnecessary exposure to light .
– Clean the sampling point prior to the sample being taken .
– First run off a sufficient quantity of oil to remove any contaminants that may have accumulated at the sampling orifice .
– Rinse the containers and caps with the oil being sampled .
– Fill the containers by allowing liquid being sampled to flow against the sides of the containers , thus avoiding trapped air .
– Ensure that each container is filled to about 95% of its capacity to avoid the possibility of leakage due to expansion of the oil during transportation .
– After sampling , close the sampling valve carefully and re-clean to avoid environmental pollution .
– Clean the outside of the sample containers .
– Label the sample containers including at least the following information :
  _ equipment identification ;
  _sampling point ;
  _ testing requirements ;
  _ temperature of the oil during sampling ;
  _ date of sampling ,
  _ date of filling , refilling or make up .
– Check that the label marking are correct and complete .

It is essential that packaging intended to transport sample containers is strong enough to protect the sample container against breakage from mechanical shock .