Reduction in Emissions from the Recycling of Transformer Oil

Submitted to the American Carbon Registry

Submitted by Hydrodec Group PLC

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Section 1: Background and Applicability

1.1 Introduction

The United States is the largest consumer of energy in the world and consequently millions of gallons of transformer oil reach the end of its service each year. Transformer oil or insulating oil is a highly refined oil that is stable at high temperatures and has excellent electrical insulating properties. It is used in oil-filled transformers, as well as some types of high-voltage capacitors, switches and circuit breakers. Its functions are to insulate, suppress corona and arcing and to serve as a coolant. When transformer oil reaches the end of its life, it is usually unfit for further use because of its accumulated contaminants and the loss of electrical, chemical and physical performance. However, using advanced technology, it is possible to treat this oil and recycle it. Recycling this kind of oil avoids emissions because the waste oil is most typically incinerated, destroying its toxic contaminants. This incineration causes CO_2 emissions, which can be avoided through recycling. In addition, the project can displace the emissions associated with the extraction, refining and transport of crude oil that would otherwise be used for transformers. Oil used in the electricity distribution sector also contains Polychlorinated Biphenyls (PCBs), and this project requires the proper treating and disposal of PCBs which are a known carcinogen. One main environmental benefit of the project is therefore the elimination of health and safety risks associated with the destruction of PCBs

1.2 Applicability Criteria

Project Proponents can achieve emissions reductions by recycling transformer oil used in transformers that are used and operated by electric utility customers and large industrial companies that would otherwise be combusted, thus generating CO_2 emissions. This methodology is applicable under the following conditions:

- For projects that treat used transformer oil, remove toxic contaminants like PCBs, and re-use the oil in utility transformers.

- It can be demonstrated that in the absence of the project, the transformer oil would have been incinerated.

- The transformer oils re-refined by the project activity in a waste-oil refinery (hereafter referred to as "Project Site") are of the same quality as the original raw products, as evidenced by the fact that they can definitely be used for the same purpose as the original oil.

- The project complies with all local or national regulations related to proper disposal of toxic substances such as PCBs.

- Projects using this methodology will have a crediting period of 7 years.

1.3 Periodic Reviews and Revisions

The American Carbon Registry® (ACR) may require revisions to this methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project activities. This methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the Project Proponent should ensure that they are using the latest version of the methodology.

Once a GHG Project Plan is certified and validated, it remains valid for the duration of the project Crediting Period regardless of methodology updates. An Annual Attestation by the Project Proponent is required. Validation is required once per Crediting Period, and verification is required prior to any new issuance of ERTs, as described in the *ACR Standard*. ACR will review Annual Attestations and periodic verification statements and notify the Project Proponent of any required adjustments or corrections to these documents. Once a GHG Project Plan has been certified by ACR, the project may be listed. Once ACR has accepted a verification statement, ACR will register verified emission reductions as ERTs.

Section 2: Project Boundaries

ACR defines the GHG offset project boundary to include a project's geographical implementation area, temporal boundary, and the GHG assessment boundary (i.e. GHG sources included).

2.1 Physical Boundary

The physical boundary is defined as the location where the waste oil is collected, the refining and treatment facility, as well as the location where the recycled oil is used. Also considered as part of the project but not explicitly in the project boundary is the infrastructure needed to extract and refine the oil that is used in the baseline situation. See Figure 1 for an illustration of the physical boundary,

Figure 1: Project Boundaries
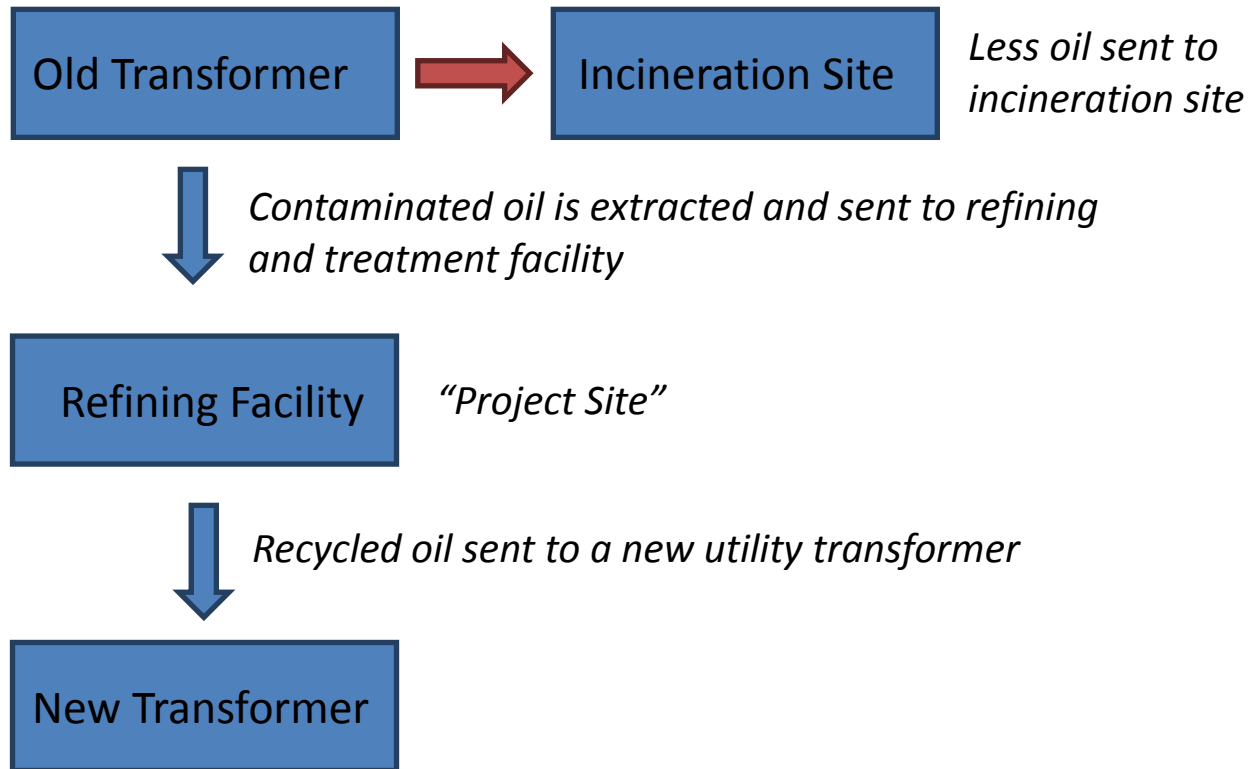
2.2 Temporal Boundary

Per the *ACR Standard,* the project Start Date is the date on which the project began to reduce GHG emissions against its baseline. For projects under this project, the Start Date corresponds to

the project facility's first operating hour. The earliest eligible Start Date for this project type is January 1, 2000. Thus, historic start date projects are eligible to earn ERTs as long as they comply with ACR guidelines on additionality and start-date.

Per the *ACR Standard,* the project Crediting Period is the length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. Projects using this methodology will have a Crediting Period of seven (7) years, with the first Crediting Period beginning on the Start Date. Crediting Periods may be renewed by re-submitting the GHG Project Plan in compliance with current ACR baseline, additionality and monitoring standards at the time of renewal.

2.3 GHG Assessment Boundary

The GHG assessment boundary encompasses all primary effects and significant secondary effects associated with the project. The GHG assessment boundary is used to identify the GHG emission sources that must be examined to quantify a project's GHG reductions, as well as sources that may be excluded either because they are insignificant or because exclusion is conservative (i.e. will lead to an underestimate of net GHG reductions).

Table 1. Emission Sources included in the GHG Assessment Boundary

Greenhouse gases and sources

	Gas	**Included/Excluded**	**Description**
Baseline	CO_2	Included	Main gas emitted from the combustion of used transformer oil in the baseline
	CH_4	Excluded	Some CH_4 may be emitted during combustion of baseline fuel, but these are expected to be negligible.
	N_2O	Excluded	Some N_2O may be emitted during combustion of baseline fuel, but these are expected to be negligible.
	CO_2	Included	Main gas emitted from the operation of the project facility (electricity, fuel usage as well as combustion of syngas)

Project	CH$_4$	Excluded	Some CH$_4$ may be emitted from project-related fossil fuel emissions, but these are expected to be negligible.
	N$_2$O	Excluded	Some N$_2$O may be emitted from project-related fossil fuel emissions, but these are expected to be negligible.

Section 3: Baseline Determination and Additionality

3.1 Baseline Determination

The baseline scenario is the continued incineration of used transformer oil . Project Proponents must demonstrate that the recycling of used transformer oil to meet specifications for re-use in transformers is not common practice per the Additionality assessment in Section 3.2. In some cases, small amounts of transformer oil are recycled to a lesser, technical short-term use, although the vast majority of it is destroyed in incineration or combustion processes, thus emitting CO_2 to the atmosphere. As described in Section 3.2, Project Proponents should demonstrate that the type of oil they refine and recycle cannot be refined and recycled using common technology (e.g.: the oil is too contaminated and requires advanced treatment and cleaning that is uncommon in the market). In these cases, it can be assumed that 100% of the oil would have otherwise been incinerated. Otherwise, Project Proponents should apply a baseline discount factor that accounts for the amount of oil that would, even in the absence of the project, be recycled. For example, in the United States, it is estimated that 5-10% of the used transformer oil is recycled to a lesser secondary one-off use, although this may vary from utility to utility or region to region. If current practice shows that a percentage of the oil is recycled, a discount factor should be applied as described in Section 4. Project Proponents should use interviews with utility or industrial officials, surveys and sampling, third-party data, industry reports or other means to determine the baseline level of oil recycling for a particular project.

3.2 Additionality

Emission reductions from the project must be additional, or deemed not to occur in the business-as-usual scenario. Assessment of the additionality of a project will be made based on passing the three tests cited below. Project Proponents utilizing this methodology should consult the latest version of the *ACR Standard*, which may be updated from time to time. At the time of the drafting of this methodology, the three additionality tests include:

1. Regulatory Surplus Test
2. Common Practice Test, and
3. Implementation Barriers Test

Further guidance on these tests is given below:

TEST 1: Regulatory Surplus: In order to pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect now, or as of the project Start Date, that directly or indirectly affect the credited GHG emissions associated with a project. The Project Proponent must demonstrate that there is no

existing regulation that mandates the project or effectively requires the recycling of transformer oil (including for reasons other than avoiding GHG emissions).

TEST 2: Common Practice Analysis: The common practice test is designed to demonstrate that this project type is not already being undertaken as a matter of common practice. It is to answer the question of whether, in the utility industry, waste transformer oil is routinely recycled instead of combusted. The GHG Project Plan should demonstrate within reason that recycling of used transformer oil is not common practice in the electric utility industry. For example, this assessment could sample market data about how different utilities dispose of their waste transformer oil. While some oil in the market may be recycled, the use of a new or more expensive technology to recycle particularly contaminated oil – such as oil with high levels of silicon – could mean that oil would otherwise be incinerated. Project Proponents can demonstrate that the *use of the technology* is not common practice by providing clear evidence that its technology is more expensive than its competitors and thus has little presence in the market. In addition, the oil may be recycled at a higher cost, which might mean in the absence of the project, that oil would be incinerated.

TEST 3: Implementation Barrier Analysis: The Project Proponent should establish that the project overcomes at least one prohibitive financial, technological, or institutional barrier. In order to demonstrate that there are prohibitive barriers to the project being implemented, the Project Proponent will provide documented evidence, and offer conservative interpretations of this evidence, as to how the project is overcoming the identified barrier. Anecdotal evidence can be included, but alone is not sufficient proof of barriers. Demonstration of the project facing at least one of the three barriers below is required for approval of the project.

Financial Barriers: The financial barriers test is intended to answer the following question: Does the project face capital constraints that carbon revenues can potentially address; or is carbon funding reasonably expected to incentivize the project's implementation; or are carbon revenues a key element to maintaining the project action's ongoing economic viability after its implementation? To pass the financial barriers test, the project should face capital constraints that carbon revenue will play a significant role in helping it overcome. Financial constraints can include, but are not limited to:

- High costs – material and personnel costs associated with construction of the project.
- Immaterial or low returns – project IRR does not meet company thresholds
- Limited access to capital or capital constraints due to the nature of the project
- High risks from new or unproven business models

If the financial barriers test is selected for the project, the Project Proponent should both explain the financial barriers and provide sufficient supporting documentation at the time of the project

validation. In this case, an example of possible financial analysis argument could be that the Project Proponent is forced to buy the old transformer at a higher price to secure the used oil than another company that would simply burn it. In this case, the revenues from the sale of carbon credits could help support the overall project financially enough to outbid competitors without eliminating the project's profitability. If any financial barriers test is used, the Project Proponent should provide a full financial analysis.

Technological Barriers: The technological barriers test is intended to answer the following question: Is a primary reason for implementation of the technology in question its GHG reduction capabilities or benefits, and is the reduction of GHG emissions one of the goals of the project at the Start Date? Technological barriers can include high R&D costs, deployment risk of new technologies, and lack of trained personnel available on-site to install, maintain, or properly operate the equipment or any other relevant technological barriers. If the technological barriers test is selected for the project, the Project Proponent should both explain the technological barriers and provide, at the time of the project validation, sufficient supporting documentation.

Institutional Barriers: The institutional barriers test is intended to answer the following question: Does the project face significant organizational, cultural, or social barriers to achieving GHG emission reductions that the accrual of benefits from the project action will help to overcome? Institutional barriers can include a scarcity of human resources for technology implementation, lack of support from management or operations personnel for new technology practices, an aversion to investment in an area where risks and returns are unfamiliar (as opposed to actual capital constraints), lack of awareness or concern with the benefits of the project, or any other relevant institutional barriers. If the institutional barriers test is selected for the project, the Project Proponent should both explain the institutional barriers and provide, at the time of the project validation, sufficient supporting documentation.

Section 4. Quantification of Baseline and Project Emissions

4.1 Baseline Emissions

Baseline emissions (BE_y) will be determined in the following manner.

$$BE_y = BE_{TOI,y} * DF \qquad (1)$$

Where

$BE_{TOI,y}$ = Baseline emissions from transformer oil incineration (TOI) that is _not_ taking place as a result of the recycling (tCO_2eq).

DF = Discount factor to account for the fact that some transformer oil may be recycled in the baseline case. Project Proponents should use interviews with utility officials, surveys and sampling, third-party data, industry reports or other means to determine the baseline level of oil recycling for a particular project. This analysis should be updated at a minimum of every five years. Alternatively, a conservative default of 10% may be used.

$BE_{TOI,y}$

$$BE_{TOI,y} = \sum FC_{TO,y} * EF_{TO,y} \qquad (2)$$

$FC_{TO,y}$ Is the energy content of baseline fuel, the transformer oil (TO) that would otherwise be combusted in year y (terrajoule or TJ).

$EF_{TO,y}$ Is the emission factor of *TO* in year y (tCO_2/TJ) (see below).

Where fuel data are collected in US gallons, the amount of fuel of a particular kind combusted in year *y* ($FC_{TO,y}$) can be estimated as

$$FC_{TO,y} = \frac{Gallons_{Fuel,TO,y} \times Density_{Fuel,TO,y} \times NCV_{Fuel}}{10^6}$$

$$(3)$$

Where

$FC_{TO,y} =$ Energy content of TO in year y; TJ

$Gallons_{Fuel,TO,y} =$ Quantity of TO collected for recycling year *y*; gal

$Density_{Fuel,TO,y} =$ Density of TO; kg.gal-1.

NCV_{Fuel} =   Net Calorific Value of TO (Gg-1.)

For each of these factors – the emissions factor ($EF_{TO,y}$), the density and the NCV – Project Proponents may elect to use the defaults in Tables 3 to 5 in Section 4.2 for Gas/Diesel Oil because transformer oil most closely matches this type of hydrocarbon. If the transformer oil is different from the energy and carbon content of diesel fuel, then Project Proponents should outline the procedures for measuring these factors or justify an alternative default. *NCV and EF defaults:* The rationale of using diesel fuel as defaults for the NCV and EF can be justified as follows. Transformer oil is a highly specified product therefore highly consistent material. In use, its primary characteristics do not change significantly so it comes to us as a waste, in energy terms, essentially unchanged. The energy content and emission factors for a fuel are substantially determined by its carbon chain length. Transformer oil is typically longer chain than diesel also making it slightly denser giving it a higher carbon and energy content per unit volume or mass. For this reason using diesel is a conservative way to approximate the energy content and emission factors for transformer oil. Doing a direct measure would create a higher CO2 emission than using the known diesel numbers. According to one source, the New Zealand Ministry of Environment, the following table illustrates the length of hydrocarbons, including transformer oil.

Table 2: Carbon chain lengths for typical hydrocarbons

Product	Minimum Carbon number	Maximum Carbon number
Natural gas	1	1
CNG	1	2
LPG	2	3
Ligroine	4	7
Mineral spirits	7	11
Toluol	6	6
Petrol	4	12
Diesel	8	17
Xylol	7	7
Kerosene	8	17
Aviation turbine fuel	8	16
Gas oil, fuel oil	11	High
Transformer oil	15	High

Source: New Zealand Ministry of Environment

Annex B also provides the standard for transformer oil from ASTM International, formerly known as the American Society for Testing and Materials. ASTM is a globally recognized leader in the development and delivery of international voluntary consensus standards.

4.2 Project Emissions

Project Emissions (PE) are determined primarily from the electricity and fuel requirements from the Project Site itself, the location which refines the old transformer oil. PE can be calculated as follows:

$$PEy = PE_{elec} + PE_{ffc} \qquad\qquad (5)$$

Where

PEy = Project emissions for year y of the crediting period

PE_{elec} = Project emissions from the use of electricity at the refining facility.

PE_{ffc} = Project emissions from the combustion of fossil fuels used for the refining facility, such as use in boilers or on-site electricity generation.

PE_{elec}

$$PE_{elec} = (Q_{electricity,y} * RateeGRID / 2,205) \qquad\qquad (6)$$

Where

$Q_{electricity,y}$	Quantity of electricity used by the Project Site in year y (MWh)
Rate*eGRID*	Emission rate for CO_2, by (in order of preference) Power Control Area, eGRID subregion, or State; lb/MWh. The latest available version of eGRID at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html shall be used. See more detail below.
2205	Conversion from lb/MWh to metric tons/MWh

Calculation of Rate*eGRID*: The CO_2 emissions from power generation are estimated using data from the USEPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of electric power generated in the United States, including emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide, net generation, resource mix, and other attributes.[1] As of publication of this methodology, the latest release is eGRID2012 version 1.0, containing data through 2009. The latest published version of eGRID shall always be used.

eGRID2012 provides data organized by power control area (PCA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The PCA, eGRID subregion, and NERC region data are based on electricity generation, transmission and distribution areas so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve load in those areas.

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[1] See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

The Project Proponent must use emission factors from the latest version of eGRID. The Proponent should download, from the eGRID website, the data files spreadsheet; for eGRID2012 Version 1.0, this is called "eGRID2012 year 2009 data files.xls". Note the "Contents" tab shows the various levels of aggregation included in the other spreadsheet tabs.

To calculate CO_2 emissions from the electric power consumed by refining facility included within the project boundary, the Project Proponent will multiply total kWh consumed for that TSE location and reporting period by one of the following eGRID emission factors, drawn from the data spreadsheet. *The data aggregation levels are to be used in the order of preference below; i.e. if the PCA can be identified the emission factor from this tab must be used. Only if it is not possible to use the preferred level of aggregation is it permitted to move to the next level.*

1. In eGRID2012 version 10, the **PCAL09** tab has data for 119 Power Control Areas across the United States. This methodology considers those PCA emission factors to be the most precise representation of emissions caused by TO recycling facilities and thus requires the PCA emission rate to be used as long as the PCA can be identified. In the **PCAL09** tab, look up the appropriate PCA in the left-hand column and scroll across to the column giving the **PCA annual CO_2 non-baseload output emission rate** in lb/MWh.

2. *Only if the PCA is not known*, use the eGRID subregion data in the **SRL09** tab. This includes emission factors for 26 eGRID subregions covering the United States (see "eGRID2012_eGRID subregion representational map," reproduced in Annex A. Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column giving the **eGRID subregion annual CO_2 non-baseload output emission rate** in lb/MWh.

3. *Only if the PCA is not known and it is not feasible to place the TSE facility definitively in an eGRID subregion* (e.g. because it is located near a boundary between two subregions), use the data aggregated by U.S. state in the **ST09** tab. This will be the least precise because electricity generation, transmission and distribution regions do not follow state boundaries. Look up the state where the TSE facility is located in the left-hand column and scroll across to the column giving the **State annual CO_2 non-baseload output emission rate** in lb/MWh.

PE_{ffc}

$$\mathbf{PE_{ffc}} = \sum_{a} FC_{a,y} * EF_{a,y} \qquad\qquad (7)$$

$FC_{a,y}$ — Energy content of fuel type a combusted the year y (terrajoule or TJ).

$EF_{a,y}$ — Emission factor of fuel type *a* in year y (tCO_2/TJ). Project Proponents can use a default for $EF_{a,y}$ as outlined in Table 3 below and on p. 47 of the [ACR Tool for Estimation of Stocks in Carbon Pools and Emissions from Emission Sources.](#)

a — Fuel types combusted during year y

Where fuel data are collected in US gallons, the amount of fuel of a particular kind combusted in year y ($FC_{a,y}$) can be estimated as

$$FC_{a,y} = \frac{Gallons_{Fuel,a,y} \times Density_{Fuel,a,y} \times NCV_{Fuel}}{10^6}$$

(8)

Where

$Fuel_{a,y}=$	Energy content of fuel type a consumed in year y; TJ
$Gallons_{Fuel,a,y}=$	Quantity of fuel of type a consumed in year y; gal
$Density_{Fuel,a,y}=$	Density of fuel type a; kg.gal-1. See Table 4.
$NCV_{Fuel}=$	Net Calorific Value of Fuel type a; TJ.Gg-1. See Table 5 below.

Table 3: Emission Factors for Fuels

Fuel Type	Default effective CO_2 emission factor ($tCO_2.TJ^{-1}$)
Motor gasoline	69.3
Gas/Diesel Oil	74.1
Liquefied Petroleum Gases	63.1
Kerosene	71.9
Lubricants	73.3
Compressed Natural Gas	56.1
Liquefied Natural Gas	56.1

The emission factors assume that 100% of the carbon content of the fuel is oxidized during or immediately following the combustion process (for all fuel types in all vehicles) irrespective of whether the CO_2 has been emitted as CO_2, CH_4, CO or NMVOC or as particulate matter.

Table 4. Typical Density Values for Selected Petroleum Products.

Typical Density Values for Selected Petroleum Products

Fuel Type	Density (kg.ltr^{-1})	Liters per ton	Density (kg.gal^{-1})	Gallons per ton

Motor gasoline	0.7407	1350	2.800	357
Gas/Diesel Oil	0.8439	1185	3.190	313
Naphtha	0.6906	1448	2.610	383
Aviation gasoline	0.7168	1350	2.710	357
Aviation Turbine fuel	0.8026	1246	3.034	330
Other kerosene	0.8026	1246	3.034	330

Table 5. Default Net Calorific Values (NCV) for Selected Petroleum Products.

Default NCVs are presented in tables below.

Fuel Type	Density $(kg.ltr^{-1})$	NCV $(GJ.t^{-1})^a$
Motor gasoline	0.7407	44.75
Gas/Diesel Oil	0.8439	43.38
Naphtha	0.6906	45.34
Aviation gasoline	0.7168	45.03
Aviation Turbine fuel	0.8026	43.92
Other kerosene	0.8026	43.92

[a] 1000 GJ = 1 TJ

Table: Default NCVs (excerpt from table 1.2, Chapter 1, Volume 2, IPCC, 2006 Inventory Guidelines)

Fuel type (English description)	Default Net Caloric Value (NCV) $(TJ.Gg^{-1})^b$
Crude Oil	42.3
Orimulsion	27.5
Natural Gas Liquids	44.2
Motor Gasoline	44.3
Aviation Gasoline	44.3
Jet Gasoline	44.3
Jet Kerosene	44.1
Other Kerosene	43.8
Gas/Diesel Oil	43.0

4.3 Leakage

Leakage (L_y) is defined as an increase in emissions outside the project boundary attributable to the implementation of the project. In cases where leakage occurs, it must be accounted for and subtracted from the reported net GHG emission reductions for the verification period. In this case, all potential sources of emissions are accounted for in the project boundary and it is unlikely that any emissions would occur outside the project boundary. Thus leakage does not need to be considered in this case.

4.4 Emission Reductions

Emission reductions can be calculated by subtracting Project Emissions PE_y (emissions happening as a result of the project) from Baseline Emissions, BE_y (the emissions that would have occurred in the absence of the project).

$$ER_y = BE_y - PE_y \qquad\qquad (9)$$

Section 5: Data Collection and Monitoring

5.1 Monitoring Plan Guidelines

A monitoring plan is a working document that describes procedures for collecting activity data, baseline and project emissions data, and for ensuring and controlling the quality of the collected data. The project monitoring plan will be updated whenever the methodologies used to measure project activity or baseline emissions are changed. Some of the key GHG accounting principles that should drive the design of data collection and monitoring include:[2]

- *Relevance*: levels of accuracy and uncertainty associated with monitoring approaches should reflect the intended use of the data and the objectives of the offset project. Some intended uses may require greater accuracy than others.

- *Accuracy*: measurements, estimates, and calculations should be unbiased, and uncertainties reduced as far as practical. Calculations and measurements should be conducted in a manner that minimizes uncertainty.

- *Conservativeness*: where there are uncertainties in monitored data, values used to quantify GHG reductions should err on the side of underestimating rather than overestimating reductions.

It is critical for the accuracy and transparency of calculating, monitoring and verifying GHG reductions that:

- Amount of oil collected and treated is weighed with industry-standard accuracy using methods and scales that are annually calibrated within the manufacturer's specifications.

- All information required to capture project emissions are calculated using data obtained as accurately as possible, including: electricity consumed at the Project Site and fuel combusted at the project site, if any. Project Proponents should develop a monitoring system and database to transfer records, such as utility bills (providing detailed accounting of power and gas used) as well as diesel or other fuel shipments. This database and individual records, such as utility bills, may be spot-checked during verification.

Table 6: Parameters Monitored

Parameter	Description	Data Unit	Calculated [c], Measured	Measurement frequency	Comment

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[2] Based on World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), *GHG Protocol for Project Accounting*, November 2005.

			[m], Reference [r], Operating records [o]		
$Q_{electricity,y}$	Electricity requirements for the facility	MWh	M	Continuously	On-site records from utility bills
$Gallons_{Fuel,a,y}$	Quantity of fuel of type *a* consumed in year *y* associated with the refining facility *(Project Site)*	Gallons	M	Continuous	On-site records from fuel purchases
Rate*eGRID*	Emission rate for CO_2, by (in order of preference) Power Control Area, eGRID subregion, NERC region, or State	Lb CO_2/MWh	R	Annual	Use most recently available eGrid Database[3]
$Gallons_{Fuel,TO,y}$ and $Gallons_{Fuel,a,y}$	Quantity of transformer oil that is captured and recycled in year *y* (baseline) and quantity of fossil fuel used in Project Site (project)	Gallons	M	Continuous	On-site records
$Density_{Fuel,TO,y}$ and $Density_{Fuel,a,y}$	Density of transformer oil (TO) (baseline) and of fossil fuel used in Project Site (project)	kg.gal-1.	R	Once	See Table 4
$EF_{TO,y}$ and $EF_{a,y}$	Emission factor of *TO* baseline) and of fossil fuel used in Project Site	tCO_2/TJ	R	Once	See Table 3

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[3] See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

	(project) in year y				
NCV_{Fuel}	Net Calorific Value of TO baseline) and of fossil fuel used in Project Site (project)	(GJ/t)	R	Once	See Table 5
EF_{COP}	Default emissions factor for methane emissions associated with crude oil production	tCH4/PJ	R	Once	See Table 2

5.2 Validation and Verification Interval

Per the *ACR Standard*, validation of the GHG Project Plan will occur once per Crediting Period. Verification of GHG assertions is at the discretion of the Project Proponent, provided it conforms to ACR requirements. Verification must occur prior to any new issuance of ERTs. ERTs may be created and issued annually, or at the Proponent's request, more or less frequently. At each request for issuance of new ERTs, the Project Proponent must submit a verification statement from an approved verifier based on a desk audit. No less than once every five years, Proponents must submit a verification statement based on a full verification including a field visit to the Project Site, the location where the transformer oil is being re-refined.

Section 6: Emissions Ownership

6.1 Statement of Direct Emissions

The Project Proponent shall attest that all emission reductions occur on the property owned and/or controlled by the Project Proponent and that none of the emissions claimed by the project are indirect emissions.

6.2 Permanence

Project Proponents should demonstrate that the emissions reduced by the project are permanently reduced. In this case, it can be reasonably expected that the emission reductions are permanent because in the absence of the project, the transformer oil would have been incinerated. Even if the recycled oil is used only once and then incinerated, is has still displaced once oil that would have otherwise been incinerated. This can therefore be considered a net emissions reduction. No buffer contribution or other risk mitigation mechanism is therefore required under this methodology.

6.3 Title

Project Proponents should provide evidence that they have title or contractual rights to the emission reductions claimed in the GHG Project Plan and monitoring reports and that no other entity has a conflicting claim over the emission reduction claimed in the in the GHG Project Plan and monitoring reports. Project Proponents seeking ERTs must deal with potential scenarios in which other parties involved in these projects can possibly claim ownership of the credits. These parties must have contractual arrangements necessary to ensure that ownership of emission reductions is clear, uncontested and rests with only one party. In this scenario the Project Proponent would need to ensure that the user of the recycled oil is not also claiming carbon credits.

6.4 Community and Environmental Impacts

If there are any significant impacts from the proposed project, the Project Proponent should take into account ACR's Community and Environmental Impacts criteria when applying this methodology to specific projects. These criteria require analysis of any adverse environmental or social impacts on the communities near the project boundary. If there are any adverse environmental problems that may result from the project itself, Project Proponents should conduct stakeholder meetings with community groups or other appropriate NGOs to ensure that any concerns associated with the project are addressed. All applicable environmental permitting and review regulations shall be complied with and all relevant stakeholders shall be consulted.

Per the *ACR Standard*, community and environmental impacts must be net positive overall. Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts, and shall disclose in their Annual Attestations

any negative environmental or community impacts or claims by community members of negative environmental and community impacts.

6.5 Warranties

The Project Proponent shall include in the GHG Project Plan the following warranty: "I hereby warrant that all information provided by [Project Proponent] in this GHG Project Plan is true and factual, and all matters affecting the validity of this GHG Project Plan or consequent emission reduction credit claims have been fully disclosed. This project has not been previously registered with any other emission reduction program or regulatory agency. [Project Proponent] has title to the GHG emission reductions created by this project, and warrants that no security has been granted over those rights, and said rights are valid. Any ERT delivery risks associated with lack of statutory rights, governmental agency recognition, or future emission reduction creation operations commensurate with potential ERT forward option volumes will be mitigated by [Project Proponent] via clearinghouse, registry, and/or insurance instruments, as appropriate."

6.6 Annual Attestations

The Project Proponent shall submit Annual Attestations, as required in the *ACR Standard*, in a format to be provided by ACR. The Annual Attestations address continued undisputed ownership of emission reductions, any claims of negative environmental or community impacts, and a mitigation plan in the case of such claims.

Section 7: QA/QC Procedures and Risk Mitigation

The Project Proponent should maintain a Quality Assurance/Quality Control (QA/QC) program including measures such as:

- Accurate measurements of weighing of waste transformer oil. The Project Proponent should retain all weigh scale receipts generated either on- or off-site indicating the weight and source of all waste oil delivered to the project facility. In the case of any missing or poor-quality data, adjustments or assumptions made as part of the QA/QC process should be made in a conservative direction, i.e. where data or assumptions used to compensate for missing data should tend to underestimate net emission reductions.

- Calibrations on key monitoring instrumentation are made at least annually or per the manufacturer specifications, whichever is more frequent. More frequently calibrations may be necessary if any QA/QC issues are indicated.

- Responsible entities: field personnel and corporate data system manager shall be responsible for data capture, to ensure data are properly recorded into the database.

- A designated corporate QA/QC officer shall be responsible for the following:

  a. Development, implementation, and oversight of QA/QC procedures for measurement, calibration, and data collection of CO_2-related data;

  b. Assess calculation results to ensure data have been properly processed; and

  c. Strategies for identifying and managing missing or poor-quality data, and making any necessary adjustments to data based on findings from the QA/QC measures.

  d. Daily log sheets, calibration and maintenance records, utility bills/receipts, and other electronic and hard copy data records shall be archived for a minimum of three (3) years to support future auditing and verification activities.

- Emission reduction estimates shall be made so as to overstate project emissions and understate baseline emissions, thereby erring on the side of understating net GHG emission reductions.

Annex A: Emission Rates for eGRID Subregions

The following map and table show the eGRID subregions and GHG emission rates, used in section 4.3 to calculate CO_2 emissions from TSE use. Note these eGRID subregion rates may only be used in the case that the Power Control Area is not known. See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.
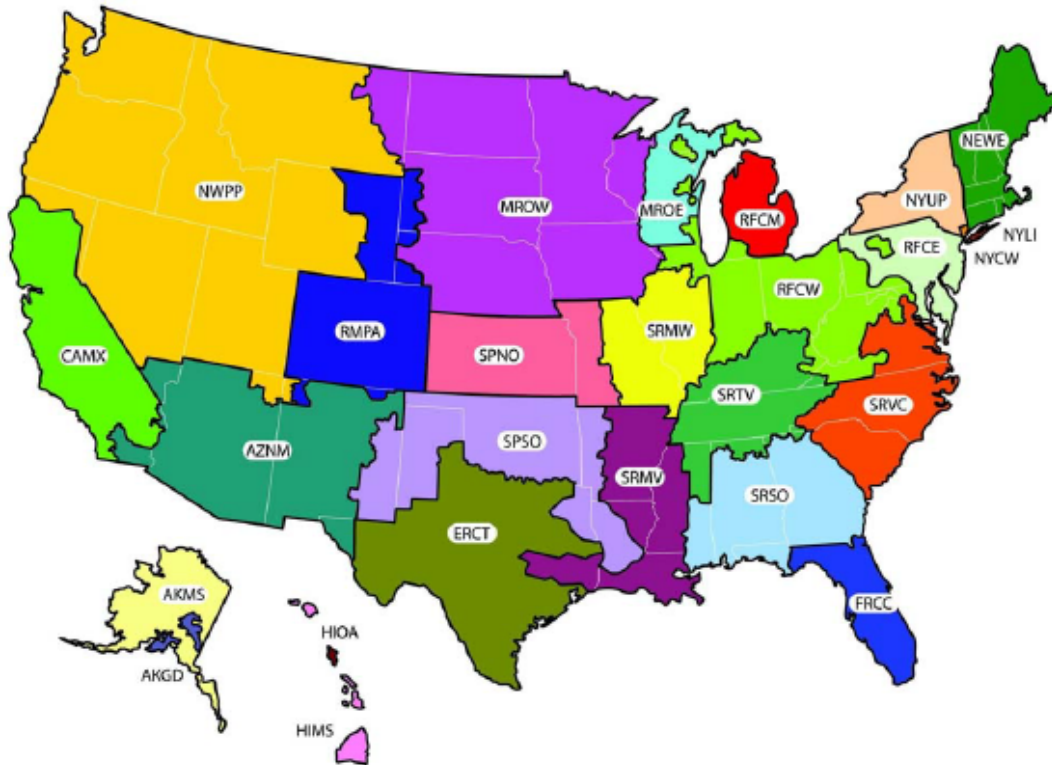
eGRID subregion acronym	eGRID subregion name	Annual total output emission rates			Annual non-baseload output emission rates		
		Carbon dioxide (CO_2) (lb/MWh)	Methane (CH_4) (lb/GWh)	Nitrous oxide (N_2O) (lb/GWh)	Carbon dioxide (CO_2) (lb/MWh)	Methane (CH_4) (lb/GWh)	Nitrous oxide (N_2O) (lb/GWh)
AKGD	ASCC Alaska Grid	1,280.86	27.74	7.69	1,320.75	33.16	6.34
AKMS	ASCC Miscellaneous	521.26	21.78	4.28	1,469.44	61.53	12.10
AZNM	WECC Southwest	1,191.35	19.13	15.58	1,187.67	22.25	9.12
CAMX	WECC California	658.68	28.94	6.17	993.89	33.52	4.07
ERCT	ERCOT All	1,181.73	16.70	13.10	1,155.44	19.66	7.59
FRCC	FRCC All	1,176.61	39.24	13.53	1,301.40	36.04	11.91
HIMS	HICC Miscellaneous	1,351.66	72.40	13.80	1,615.98	91.06	17.19
HIOA	HICC Oahu	1,593.35	101.74	21.98	1,621.42	107.94	18.73
MROE	MRO East	1,591.65	23.98	27.04	1,868.23	29.40	30.40
MROW	MRO West	1,628.60	28.80	27.79	2,114.93	61.83	37.41
NEWE	NPCC New England	728.41	75.68	13.86	1,157.44	61.72	14.43
NWPP	WECC Northwest	819.21	15.29	12.50	1,404.55	38.56	18.79
NYCW	NPCC NYC/Westchester	610.67	23.75	2.81	1,118.06	22.47	2.31
NYLI	NPCC Long Island	1,347.99	96.86	12.37	1,336.59	30.78	3.51
NYUP	NPCC Upstate NY	497.92	15.94	6.77	1,347.12	41.08	16.87
RFCE	RFC East	947.42	26.84	14.96	1,628.97	32.94	22.46
RFCM	RFC Michigan	1,659.46	31.41	27.89	1,834.66	35.17	29.15
RFCW	RFC West	1,520.59	18.12	25.13	2,001.76	24.56	32.10
RMPA	WECC Rockies	1,824.51	22.25	27.19	1,756.62	23.54	22.51
SPNO	SPP North	1,815.76	21.01	28.89	2,147.53	26.32	31.82
SPSO	SPP South	1,599.02	23.25	21.79	1,513.73	25.22	15.11
SRMV	SERC Mississippi Valley	1,002.41	19.45	10.65	1,201.66	25.72	7.11
SRMW	SERC Midwest	1,749.75	19.57	28.98	2,192.85	25.04	35.89
SRSO	SERC South	1,325.68	22.27	20.78	1,622.00	27.22	23.50
SRTV	SERC Tennessee Valley	1,357.71	17.28	22.09	1,921.12	25.16	30.61
SRVC	SERC Virginia/Carolina	1,035.87	21.51	17.45	1,677.35	38.55	25.56
U.S.		1,216.18	24.03	18.08	1,555.48	30.83	19.76

Annex B: ASTM International Standard Specification for Mineral Insulating Oil Used in Electrical Apparatus

Standard Specification for
Mineral Insulating Oil Used in Electrical Apparatus[1]

This standard is issued under the fixed designation D3487; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

This standard has been approved for use by agencies of the Department of Defense.

1. Scope

1.1 This specification covers new mineral insulating oil of petroleum origin for use as an insulating and cooling medium in new and existing power and distribution electrical apparatus, such as transformers, regulators, reactors, circuit breakers, switchgear, and attendant equipment.

1.2 This specification is intended to define a mineral insulating oil that is functionally interchangeable and miscible with existing oils, is compatible with existing apparatus and with appropriate field maintenance,[2] and will satisfactorily maintain its functional characteristics in its application in electrical equipment. This specification applies only to new insulating oil as received prior to any processing.

1.3 The values stated in SI units are to be regarded as standard. No other units of measurement are included in this standard.

2. Referenced Documents

2.1 *ASTM Standards:*[3]

D88 Test Method for Saybolt Viscosity

D92 Test Method for Flash and Fire Points by Cleveland Open Cup Tester

D97 Test Method for Pour Point of Petroleum Products

D445 Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and Calculation of Dynamic Viscosity)

D611 Test Methods for Aniline Point and Mixed Aniline Point of Petroleum Products and Hydrocarbon Solvents

D877 Test Method for Dielectric Breakdown Voltage of Insulating Liquids Using Disk Electrodes

D923 Practices for Sampling Electrical Insulating Liquids

D924 Test Method for Dissipation Factor (or Power Factor) and Relative Permittivity (Dielectric Constant) of Electrical Insulating Liquids

D971 Test Method for Interfacial Tension of Oil Against Water by the Ring Method

D974 Test Method for Acid and Base Number by Color-Indicator Titration

D1275 Test Method for Corrosive Sulfur in Electrical Insulating Oils

D1298 Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method

D1500 Test Method for ASTM Color of Petroleum Products (ASTM Color Scale)

D1524 Test Method for Visual Examination of Used Electrical Insulating Oils of Petroleum Origin in the Field

D1533 Test Method for Water in Insulating Liquids by Coulometric Karl Fischer Titration

D1816 Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Using VDE Electrodes

D1903 Practice for Determining the Coefficient of Thermal Expansion of Electrical Insulating Liquids of Petroleum Origin, and Askarels

D2112 Test Method for Oxidation Stability of Inhibited Mineral Insulating Oil by Pressure Vessel

D2300 Test Method for Gassing of Electrical Insulating Liquids Under Electrical Stress and Ionization (Modified Pirelli Method)

D2440 Test Method for Oxidation Stability of Mineral Insulating Oil

D2668 Test Method for 2,6-*di-tert*-Butyl- *p*-Cresol and 2,6-*di-tert*-Butyl Phenol in Electrical Insulating Oil by Infrared Absorption

D2717 Test Method for Thermal Conductivity of Liquids

D2766 Test Method for Specific Heat of Liquids and Solids

D3300 Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Under Impulse Conditions

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[1] This specification is under the jurisdiction of ASTM Committee D27 on Electrical Insulating Liquids and Gases and is the direct responsibility of Subcommittee D27.01 on Mineral.

Current edition approved Dec. 1, 2009. Published December 2009. Originally approved in 1976. Last previous edition approved in 2008 as D3487 – 08. DOI:10.1520/D3487-09.

[2] Refer to American National Standard C 57.106. Guide for Acceptance and Maintenance of Insulating Oil in Equipment (IEEE Standard 64). Available from American National Standards Institute (ANSI), 25 W. 43rd St., 4th Floor, New York, NY 10036, http://www.ansi.org.

[3] For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

D4059 Test Method for Analysis of Polychlorinated Biphenyls in Insulating Liquids by Gas Chromatography

D4768 Test Method for Analysis of 2,6-Ditertiary-Butyl Para-Cresol and 2,6-Ditertiary-Butyl Phenol in Insulating Liquids by Gas Chromatography

D5837 Test Method for Furanic Compounds in Electrical Insulating Liquids by High-Performance Liquid Chromatography (HPLC)

3. Terminology Definitions

3.1 *Type I Mineral Oil*—an oil for apparatus where normal oxidation resistance is required. Some oils may require the addition of a suitable oxidation inhibitor to achieve this.

3.2 *Type II Mineral Oil*—an oil for apparatus where greater oxidation resistance is required. This is usually achieved with the addition of a suitable oxidation inhibitor.

NOTE 1—During processing of inhibited mineral oil under vacuum and elevated temperatures, partial loss of inhibitor and volatile portions of mineral oil may occur. The common inhibitors, 2,6-ditertiary-butyl para-cresol (DBPC/BHT) and 2,6-ditertiary-butyl phenol (DPB), are more volatile than transformer oil. If processing conditions are too severe, oxidation stability of the oil may be decreased due to loss of inhibitor. The selectivity for removal of moisture and air in preference to loss of inhibitor and oil is improved by use of a low processing temperature.

Conditions that have been found satisfactory for most inhibited mineral oil processing are:

	Minimum Pressure	
Temperature, °C	Pa	Torr, Approximate
40	5	0.04
50	10	0.075
60	20	0.15
70	40	0.3
80	100	0.75
90	400	3.0
100	1000	7.5

If temperatures higher than those recommended for the operating pressure are used, the oil should be tested for inhibitor content and inhibitor added as necessary to return inhibitor content to its initial value. Attempts to dry apparatus containing appreciable amounts of free water may result in a significant loss of inhibitor even at the conditions recommended above.

3.3 *additives*—chemical substances that are added to mineral insulating oil to achieve required functional properties.

3.4 *properties*—those properties of the mineral insulating oil which are required for the design, manufacture, and operation of the apparatus. These properties are listed in Section 5.

4. Sampling and Testing

4.1 Take all oil samples in accordance with Test Methods D923.

4.2 Make each test in accordance with the latest revision of the ASTM test method specified in Section 5.

4.3 The oil shall meet the requirements of Section 5 at the unloading point.

NOTE 2—Because of the different needs of the various users, items relating to packaging, labeling, and inspection are considered to be subject to buyer-seller agreement.

NOTE 3—In addition to all other tests listed herein, it is sound engineering practice for the apparatus manufacturer to perform an evaluation of new types of insulating oils in insulation systems, prototype structures, or full-scale apparatus, or any combination thereof, to assure suitable service life.

4.4 Make known to the user the generic type and amount of any additive used, for assessing any potential detrimental reaction with other materials in contact with the oil.

5. Property Requirements

5.1 Mineral insulating oil conforming to this specification shall meet the property limits given in Table 1. The significance of these properties is discussed in Appendix X2.

TABLE 1 Property Requirements

Property	Limit Type I	Limit Type II	ASTM Test Method
Physical:			
Aniline point, °C, min	63[A]	63[A]	D611
Color, max	0.5	0.5	D1500
Flash point, min, °C	145	145	D92
Interfacial tension at 25°C, min, dynes/cm	40	40	D971
Pour point, max, °C	−40[B]	−40[B]	D97
Relative Density (Specific gravity), 15°C/15°C max	0.91	0.91	D1298
Viscosity, max, cSt (SUS) at:			D445 or D88
100°C	3.0 (36)	3.0 (36)	
40°C	12.0 (66)	12.0 (66)	
0°C	76.0 (350)	76.0 (350)	
Visual examination	clear and bright	clear and bright	D1524
Electrical:			
Dielectric breakdown voltage at 60 Hz:			
Disk electrodes, min, kV	30	30	D877
VDE electrodes, min, kV 0.040-in. (1.02-mm) gap	20[C]	20[C]	D1816
0.080-in. (2.03-mm) gap	35[C]	35[C]	
Dielectric breakdown voltage, impulse conditions			D3300
25°C, min, kV, needle negative to sphere grounded, 1-in. (25.4-mm) gap	145[D]	145[D]	
Gassing tendency, max, µL/min	+30	+30	D2300
Dissipation factor (or power factor), at 60 Hz max, %:			D924
25°C	0.05	0.05	
100°C	0.30	0.30	
Chemical:[E]			
Oxidation stability (acid-sludge test)			D2440
72 h:			
% sludge, max, by mass	0.15	0.1	
Total acid number, max, mg KOH/g	0.5	0.3	
164 h:			
% sludge, max, by mass	0.3	0.2	
Total acid number, max, mg KOH/g	0.6	0.4	
Oxidation stability (rotating bomb test), min, minutes	—	195	D2112
Oxidation inhibitor content, max, % by mass	0.08[F]	0.3	D4768 or D2668[G]
Corrosive sulfur	noncorrosive		D1275
Water, max, ppm	35	35	D1533
Neutralization number, total acid number, max, mg KOH/g	0.03	0.03	D974
PCB content, ppm	not detectable	not detectable	D4059

[A] The value shown represents current knowledge.

[B] It is common practice to specify a lower or higher pour point, depending upon climatic conditions.

[C] These limits by Test Method D1816 are applicable only to as received new oil (see Appendix X2.2.1.2). A new processed oil should have minimum breakdown strengths of 28 kV and 56 kV for a 0.04 in. (1.02 mm) or 0.08 in. (2.03 mm) gap respectively.

[D] Currently available oils vary in impulse strength. Some users prefer oil of a 145 kV minimum for certain applications, while others accept oil with impulse strength as low as 130 kV for other applications.

[E] Furanic compounds, as determined by Test Method D5837, are useful for assessing the level of cellulose degradation that has occurred in oil impregnated paper systems. Specifying maximum allowable furan levels in new oils for this purpose should be by agreement between user and supplier.

[F] Provisions to purchase totally uninhibited oil shall be negotiated between producer and user.

[G] Both 2,6-ditertiary-butyl para-cresol (DBPC/BHT) and 2,6-ditertiary butylphenol (DBP) have been found to be suitable oxidation inhibitors for use in oils meeting this specification.

Preliminary studies indicate both Test Methods D2668 and D4768 are suitable for determining concentration of either inhibitor or their mixture.

APPENDIXES

(Nonmandatory Information)

X1. SUPPLEMENTARY DESIGN INFORMATION

X1.1 The following values are typical for presently used mineral insulating oils. For oils derived from paraffinic or mixed-base crudes, the apparatus designer needs to know that these properties have not changed.

Property	Typical Values	ASTM Test Method
Coefficient of expansion,/° C from 25 to 100°C	0.0007 to 0.0008	D1903

Property	Typical Values	ASTM Test Method
Dielectric constant, 25°C	2.2 to 2.3	D924
Specific heat, cal/g, 20°C	0.44	D2766
Thermal conductivity, cal/ cm·s·°C, from 20 to 100°C	$(0.30 \text{ to } 0.40) \times 10^{-3}$	D2717

X2. SIGNIFICANCE OF PROPERTIES OF MINERAL INSULATING OIL

X2.1 Physical Properties

X2.1.1 *Aniline Point*—The aniline point of a mineral insulating oil indicates the solvency of the oil for materials that are in contact with the oil. It may relate to the impulse and gassing characteristics of the oil.

X2.1.2 *Color*—A low color number is an essential requirement for inspection of assembled apparatus in the tank. An increase in the color number during service is an indicator of deterioration of the mineral insulating oil.

X2.1.3 *Flash Point*—The safe operation of the apparatus requires an adequately high flash point.

X2.1.4 *Interfacial Tension*—A high value for new mineral insulating oil indicates the absence of undesirable polar contaminants. This test is frequently applied to service-aged oils as an indicator of the degree of deterioration.

X2.1.5 *Pour Point*—The pour point of mineral insulating oil is the lowest temperature at which the oil will just flow and many of the factors cited under viscosity apply. The pour point of $-40°C$ may be obtained by the use of suitable distillates, refining processes, the use of appropriate long life additives, or any combination thereof. If a pour point additive is used, it is necessary to make known the amount and chemical composition.

X2.1.6 *Relative Density (Specific Gravity)*—The specific gravity of a mineral insulating oil influences the heat transfer rates and may be pertinent in determining suitability for use in specific applications. In extremely cold climates, specific gravity has been used to determine whether ice, resulting from freezing of water in oil-filled apparatus, will float on the oil and possibly result in flashover of conductors extending above the oil level. See, for example, "The Significance of the Density of Transformer Oils."[4]

X2.1.7 *Viscosity*—Viscosity influences the heat transfer and, consequently, the temperature rise of apparatus. At low temperatures, the resulting higher viscosity influences the speed of moving parts, such as those in power circuit breakers, switchgear, load tapchanger mechanisms, pumps, and regulators. Viscosity controls mineral insulating oil processing conditions, such as dehydration, degassification and filtration, and oil impregnation rates. High viscosity may adversely affect the starting up of apparatus in cold climates (for example, spare transformers and replacements).

X2.1.8 *Visual Examination*—A simple visual inspection of mineral insulating oil may indicate the absence or presence of undesirable contaminants. If such contaminants are present, more definitive testing is recommended to assess their effect on other functional properties.

X2.2 Electrical Properties

X2.2.1 *Dielectric Breakdown Voltage, 60 Hz*—The dielectric breakdown voltage of a mineral insulating oil indicates its ability to resist electrical breakdown at power frequencies in electrical apparatus.

X2.2.1.1 *Dielectric Breakdown—Disk Electrodes*—The test utilizing disk electrodes is useful in assessing the quality of the mineral insulating oil as received in tank cars, tank trucks, or drums. It is not sensitive enough to determine if an oil meets the minimum acceptable breakdown strength needed for processed oil used in some equipment.

X2.2.1.2 *Dielectric Breakdown—VDE Electrodes*—The VDE method (Test Method D1816) is sensitive to contaminants, such as water, dissolved gases, cellulose fibers, and conductive particles in oil. Processing involves filtering, dehydration, and degassing, which generally improve the breakdown strength of the oil. As a general guide, the moisture and dissolved gas content by volume in processed oils should be less 15 ppm and 0.5 % respectively. The minimum breakdown strength for as received oils is typically lower than that of processed oils because of higher levels of contaminants.

X2.2.2 *Dielectric Breakdown Voltage–Impulse*—The impulse strength of oil is critical in electrical apparatus. The impulse breakdown voltage of an oil indicates its ability to resist electrical breakdown under transient voltage stresses (lightning and switching surges). The functional property is sensitive to both polarity and electrode geometry.

X2.2.3 *Dissipation Factor*—Dissipation factor (power factor) is a measure of the dielectric losses in an oil. A low

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[4] Mulhall, V. R., "The Significance of the Density of Transformer Oils," *IEEE Transactions on Electrical Insulation*, Vol 15, No. 6, December 1980, pp. 498–499. DOI: 10.1520/D3487-09_WIP_#872079.

dissipation factor indicates low dielectric losses and a low level of soluble contaminants.

X2.3 Chemical Properties

X2.3.1 *Oxidation Inhibitor Content*—Oxidation inhibitor added to mineral insulating oil retards the formation of oil sludge and acidity under oxidative conditions. It is important to know if an oxidation inhibitor has been added to the oil and the amount. 2,6-Ditertiary-butyl para-cresol and 2,6-ditertiary butylphenol have been found suitable for use in mineral insulating oils complying with this specification. It is anticipated that other oxidation inhibitors will be accepted.

X2.3.2 *Corrosive Sulfur*—The absence of elemental sulfur and thermally unstable sulfur-bearing compounds is necessary to prevent the corrosion of certain metals such as copper and silver in contact with the mineral insulating oil.

X2.3.3 *Water Content*—A low water content of mineral insulating oil is necessary to achieve adequate electrical strength and low dielectric loss characteristics, to maximize the insulation system life, and to minimize metal corrosion.

X2.3.4 *Neutralization Number*—A low total acid content of a mineral insulating oil is necessary to minimize electrical conduction and metal corrosion and to maximize the life of the insulation system.

X2.3.5 *Oxidation Stability*—The development of oil sludge and acidity resulting from oxidation during storage, processing, and long service life should be held to a minimum. This minimizes electrical conduction and metal corrosion, maximizes insulation system life and electrical breakdown strength, and ensures satisfactory heat transfer. The limiting values in accordance with Table 1, as determined by Test Methods D2112 and D2440, best achieve these objectives.

X2.3.6 *Gassing*—The gassing tendency of a mineral insulating oil is a measure of the rate of absorption or desorption of hydrogen into or out of the oil under prescribed laboratory conditions. It reflects, but does not measure, aromaticity of the oil. Most oil-filled transformers are blanketed with nitrogen or oxygen-depleted air. The gassing tendency of oil under nitrogen does not directly relate to its gassing tendency under hydrogen. No quantitative relationship has been established between the gassing tendency of an oil, as indicated by the results of Test Method D2300, and the performance or life of that oil in service.

X2.3.7 *PCB Content*—United States regulations specify procedures to be followed for the use and disposal of electrical apparatus and electrical insulating fluids containing PCB (polychlorinated biphenyls). The procedure to be used for a particular apparatus or lot of insulating fluid is determined from its PCB content. New mineral insulating oil of the type covered by this specification should not contain any detectable PCB. A nondetectable PCB concentration measured by Test Method D4059 provides documentation to permit the insulating oil and apparatus containing it to be used without the labeling, recordkeeping, and disposal restrictions required of PCB-containing materials.

X3. CRUDE OILS, REFINING PROCESSES, AND SHIPPING CONTAINERS

X3.1 *Crude Oils*—Mineral insulating oils are presently refined from predominantly naphthenic crude oils. As the supply of such crude oils diminishes, paraffinic or mixed base crudes may be used to provide mineral insulating oil for use in electrical apparatus. As the new crudes are developed for this use, additional tests peculiar to the chemistry of these oils will need to be defined.

X3.2 *Refining Processes*—Distillates from crude oils may be refined by various processes such as solvent extraction, dewaxing, hydrogen treatment, or combinations of these methods to yield mineral insulating oil meeting the requirements of this specification. The generic process should be specified upon request.

X3.3 *Shipping Containers*—Mineral insulating oil is usually shipped in rail cars, tank trucks (trailers), or drums. Rail cars used for shipping mineral insulating oil are usually not used for shipping other products and are more likely to be free of contamination. Tank trucks may be used for many different products and are more subject to contamination. Oil drums are most often used for shipping small quantities. All shipping containers, together with any attendant pumps and piping, should be cleaned prior to filling with oil and should be properly sealed to protect the oil during shipment.

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