RECLAMATION
Managing Water in the West

Alternate Insulating Fluids for Power Transformers

Research and Development Office
Science and Technology Program
(Final Report) ST-2019-100-01

U.S. Department of the Interior
Bureau of Reclamation
Research and Development Office

October 1, 2019

Mission Statements

The U.S. Department of the Interior protects America’s natural resources and heritage, honors our cultures and tribal communities, and supplies the energy to power our future.

The Department of the Interior protects and manages the Nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors its trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities.

REPORT DOCUMENTATION PAGE		*Form Approved* *OMB No. 0704-0188*
T1. REPORT DATE: SEPTEMBER 2019	**T2. REPORT TYPE:** RESEARCH	**T3. DATES COVERED** 2015-2019

T4. TITLE AND SUBTITLE
Alternate Insulating Fluids for Power Transformers

5a. CONTRACT NUMBER
XXXR4524KS-RR4888FARD1805201 (8)

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER
1541 (S&T)

6. AUTHOR(S)
Jeremiah Bradshaw, Professional Engineer, jbradshaw@usbr.gov
Benjamin Few, Profession Engineer, bfew@usbr.gov (Appendix A)
Sherri Pucherelli, Biologist, spucherelli@usbr.gov (Appendix B)

5d. PROJECT NUMBER
ST-100-01

5e. TASK NUMBER

5f. WORK UNIT NUMBER
86-68460

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
Bureau of Reclamation, Technical Service Center

8. PERFORMING ORGANIZATION REPORT NUMBER

9. SPONSORING / MONITORING AGENCY NAME(S) AND ADDRESS(ES)
Research and Development Office
U.S. Department of the Interior, Bureau of Reclamation,
PO Box 25007, Denver CO 80225-0007

10. SPONSOR/MONITOR'S ACRONYM(S)
R&D: Research and Development Office
BOR/USBR: Bureau of Reclamation
DOI: Department of the Interior

11. SPONSOR/MONITOR'S REPORT NUMBER(S)
ST-100

12. DISTRIBUTION / AVAILABILITY STATEMENT
Final report can be downloaded from Reclamation's website: https://www.usbr.gov/research/

13. SUPPLEMENTARY NOTES

14. ABSTRACT
This paper presents the benefits and cautions to using alternate insulating fluids for large power transformers. Specific topics that pertain to key characteristics of the fluids, transformer design, transportation, installation, operations, and maintenance are provided. Written with a focus on insulating fluid choice, specific site condition concerns are listed that assist in the final decision.

15. SUBJECT TERMS
Power Transformers, Insulating Fluids, Natural ester fluid, synthetic ester fluid, SF_6 insulating fluid

16. SECURITY CLASSIFICATION OF:			**17. LIMITATION OF ABSTRACT**	**18. NUMBER OF PAGES**	**19a. NAME OF RESPONSIBLE PERSON**
a. REPORT	**b. ABSTRACT**	**c. THIS PAGE**	U		Jeremiah Bradshaw
U	U	U			**19b. TELEPHONE NUMBER** (303) 445-2812

S Standard Form 298 (Rev. 8/98)
P Prescribed by ANSI Std. 239-18

BUREAU OF RECLAMATION

Research and Development Office
Science and Technology Program

Technical Service Center
Electrical Equipment Group, 86-68460

(Final Report) ST- ST-2019-100-01

Alternate Insulating Fluids for Power Transformers

JEREMIAH BRADSHAW
Digitally signed by JEREMIAH BRADSHAW
Date: 2019.09.30 18:07:41 -06'00'

Prepared by: Jeremiah Bradshaw, P.E.
Electrical Engineer, Electrical Equipment Group, 86-68460

ERIC MENDLIN
Digitally signed by ERIC MENDLIN
Date: 2019.09.30 19:14:17 -06'00'

Checked by: Eric Mendlin, P.E.
Manager, Electrical Equipment Group, 86-68460

JEREMIAH BRADSHAW
Digitally signed by JEREMIAH BRADSHAW
Date: 2019.09.30 18:07:59 -06'00'

Technical Approval: Jeremiah Bradshaw, P.E.
Electrical Engineer, Electrical Equipment Group, 86-68460

JAY BOGGESS
Digitally signed by JAY BOGGESS
Date: 2019.09.30 19:57:21 -06'00'

Peer Review: Jay Boggess, P.E.
Manager, Electrical Controls Group, 86-68430

Acronyms and Abbreviations

AC: Alternating Current.

CRGO: Cold-Rolled Grain-Oriented.

CTC: Continuously Transposed Conductor.

DGA: Dissolved Gas Analysis.

DF: Dissipation Factor.

EPA: Environmental Protection Agency.

FIST: Facility Instructions, Standards, and Techniques.

GSU: Generator Step-Up.

MPaG: Megapascal read from Gauge.

PF: Power Factor.

RS: Relative Saturation.

SF_6: Sulfur Hexafluoride.

Executive Summary

With growing environmental and fire protection awareness, insulating fluids for power transformers are evolving. Historically, mineral oil has been used in power transformers and this fluid is the reason for many of the design parameters, testing standards, and operating analysis tools used today. Significant benefits in alternate insulating fluids are causing a shift in the type of insulating fluid used in power transformers. These fluids have different properties which impact the design, manufacturing, and service of power transformers.

This paper presents the benefits and cautions to using alternate insulating fluids for large power transformers. Specific topics that pertain to key characteristics of the fluids, transformer design, transportation, installation, operations, and maintenance are provided. Written with a focus on insulating fluid choice, specific site condition concerns are listed that assist in the final decision.

Outcomes of investigations, testing results, and industry development provide enough information to support the use of natural ester fluid, synthetic ester fluid, and SF_6 gas as alternate insulating fluids for power transformers within the Bureau of Reclamation.

Maximum benefits of these fluids are based on the topics of concern for existing locations. The following table provides a rough summary for each fluid.

Table 1 - Summary of Insulating Fluids

Topic	**Mineral Oil**	**Natural Ester Fluid**	**Synthetic Ester Fluid**	**SF_6 Gas**
Fire Safety	Disadvantage	Advantage	Advantage	Advantage
Environmental Impact to Waterways	Disadvantage	Advantage	Advantage	Advantage
Life Expectancy	Disadvantage	Advantage	Advantage	Neutral
Oxidation Stability	Advantage	Disadvantage	Advantage	Advantage
High Temperature Operation	Disadvantage	Advantage	Advantage	Neutral

Contents

Tables

Figures

Background and Purpose

The backbone of power generation consists of the generator and generator step-up (GSU) power transformer. These assets are of the utmost importance for a generation entity and come with great investment through sophisticated designs, meticulous hand-built manufacturing, in-depth operations testing, and monitoring systems producing trending data that is analyzed to understand the life of these investments. Of these two assets, the power transformer for hydroelectric facilities typically operates in a weathered environment near or directly over a water resource which increases the risk of damage during a failure. Losing this asset unexpectedly may not only be financially detrimental but could also have high impacts to the surrounding environment.

Power transformer design, operation, and maintenance have been well documented and understood for many years. As the industry's GSU power transformer fleet reaches end of life, many utilities are investigating ways to reduce environmental impact and increase energy production, reliability, and safety during the replacement of these transformers. The growing awareness in environmental sustainability, fire protection measures, and optimization of existing space has caused the power transformer to evolve by using different insulating fluid types.

This paper provides current knowledge of the benefits and drawbacks to different dielectric insulating fluid types for GSU power transformers. Background information is provided in the design, operation, and maintenance of GSU power transformers to help illustrate impacts with respect to four insulating fluids: mineral oil, natural ester fluid, synthetic ester fluid, and SF_6 gas. Additionally, this paper will discuss project specific circumstances that may influence the choice of a certain insulating fluid type over the next. The replacement of GSU power transformers are specific to each installation and a large investment for a power generation entity; this paper does not suffice for engineering analysis and judgement specific to each project, but it can be used to help determine the correct insulating fluid for the application.

Power Transformers

Purpose

Transformers have been in use since the inception of alternating-current (AC) electrical systems. A transformer takes advantage of the power equation, which is a product of voltage and current. Using magnetic induction, a GSU power transformer increases the generator voltage to transmission voltage levels and proportionally decreases the current being transmitted from the source to the load. This directly reduces the losses of the system by allowing power to be transferred long distances with low heat losses.

To make sure these losses are reduced as much as possible, the transformer is connected as close as possible to the generator, limiting the distance of high ampacity busbars. Well-designed power transformers have high efficiencies: averaging 98% or higher. The losses of a transformer are produced by the copper windings and steel core. To reduce these losses as much as possible, sophisticated manufacturing processes have been perfected over time.

Manufacturing

GSU power transformers consist of three major internal components: windings, magnetic core, and insulating systems consisting of solid and fluid. Each of these components have evolved over time to current practices resulting in extremely high efficiencies.

The windings for large power transformers are typically made of copper due to the material properties and conductivity. The copper conductors of a transformer can be made of Continuously Transposed Conductors (CTC) which are multiple copper strands used to reduce overall size and cost of the transformer, reduce losses via stray currents, and improve malleability to ease the winding process. Typically, these conductors are wrapped with a thermal insulating material, cellulose or other, which provides isolation between winding layers, assists in mechanical properties of the coils, and is a medium for exchange of heat from the windings to insulating fluid. The copper conductors arrive on large drums and are wound by hand using either vertical or horizontal machines. Each winding is wound separately and designed with axial and radial spacers in specific locations that act as fluid channels. These channels are designed specifically to optimize the heat transfer from winding to insulating fluid.

Figure 1 - Cut Away of Transformer Windings

The magnetic coupling circuit is executed through the transformer core, which is necessary for the voltage induction between windings. A transformer core is constantly exposed to alternating magnetic fields in which hysteresis losses and circulating current losses, referred to as eddy current, are generated. These losses generate heat and, as with all electrical equipment, must be reduced to increase efficiencies and equipment life. Both shell and core form transformers can have an optimized core made of cold-rolled grain-oriented (CRGO) silicon steel. To combat against hysteresis, the steel is CRGO which means that the cubic crystal structure of the steel is oriented in such a way that all 'edges' of the structure are aligned and oriented in the same direction as the magnetization. This alignment increases the permeability and allows the core to operate at higher flux densities. Silicon is added to the steel material to slightly reduce the conductivity of the steel which helps to resist the eddy currents. These sheets of steel are constructed in an overlapping pattern to produce step laps which reduces the sharp edges of the overall core. By using CRGO silicon steel laminations and patterns that produce step laps, losses are reduced which in turn reduces heat production and energy losses in the transformer core. In addition to these measures, cooling channels can be inserted into the core to increase heat transfer. These cooling channels are designed based on heat generation of the core and insulating fluid type used.

Figure 2 - Transformer Core Showing Step Laps and Cooling Channel

The insulating system of a transformer consists of solid and fluid materials that are categorized separately by the thermal rating of each element. Both solid and fluid materials contribute to the overall thermal rating of the insulation system. Solid insulation materials such as cellulose paper, epoxy films, and pressboard provide insulation and structure for conductive components. Fluid insulation materials such as mineral oil, ester fluid, and electrical grade insulating gas assist in providing insulation for the conductive components and also provide a means for heat transfer. Although solid and fluid insulation systems have separate thermal class ratings as defined in IEEE C57.154 [1], these systems are not mutually exclusive. The solid insulation system relies on the fluid insulation system to fill voids and prevent contaminants, such as oxygen, moisture, dissolved combustible gases, and foreign materials from entering the system. The ability of solid insulation to absorb fluid insulation increases the overall insulation system's electrical strength.

Figure 3 - Solid Insulation Systems

The life of a power transformer is largely dependent on the quality and durability of the solid insulation. Normal operating temperatures of a transformer will cause aging and degradation of the insulation system; however, operating a transformer such that the insulation system is above its hottest spot temperature will result in decreased life and/or failure. The ability of the fluid insulation to remove heat from the active parts (core and coil) and limit the amount of contamination into the system is critical in maintaining a healthy, long life transformer.

Investment in Critical Assets

GSU power transformers are custom built pieces of equipment specific to each individual installation. Replacement of these units imposes significant costs and requires long lead times for procurement, manufacturer selection, purchase of materials, manufacturing, testing, special transportation, and meticulous assembly. With copper and steel playing major roles in the process, global demands of these two commodities directly affect lead times. Rough estimates for replacement of a GSU power transformer range from eight (8) to twenty-four (24) months from time of contract award to operation at the site.

North America's electrical infrastructure is one of the most reliable and advanced systems in the world. The interconnected system of over 6,000 power plants relies heavy on custom built transformers to meet the demands of the growing system. Based on a study in 2014 by the Department of Energy, 70% of these critical assets are estimated to be in operation for 25 years or more with some units in operation for over 65 years [2]. As explained previously, the useful life of a power transformer is defined by the insulation system life. Deterioration of the insulation system is a time function based on contaminants and operating temperature (loading). This is a complicated function that must address temperature uniformity issues, loading schemes, cooling methods, ambient temperature situations, age acceleration factors, and many other variables. In the simplest form a transformer's insulation life is approximately 20 years based on a continuous operation at the maximum hot spot temperature of 110-degrees Celsius [3]. Given that most critical assets in the electrical grid are reaching the end of life, the lead time on power transformers is estimated to increase.

The Bureau of Reclamation provides irrigation to 10 million farmland acres and water to 31 million people. This water resource is also used to produce an average of 44 billion kilowatt hours annually making Reclamation the 2nd largest hydroelectric power producer in the U.S. [4]. With approximately 300 power transformers in the fleet, Reclamation invests substantial time and money into maintaining this critical asset. The aging power transformer asset requires dedicated experts to analyze and determine the most suitable insulating fluids for each location.

Fluid Insulation Systems

In fluid filled transformers, the fluid insulation system provides a key role of both electrical insulation and cooling of the active part (core and coil). While in general terms, a transformer's life expectancy is directly related to the exposure of the insulating system to the maximum operating temperature, the key to temperature management is uniformity. As discussed in Manufacturing, the active parts of a transformer have cooling channels strategically placed to maximize the heat transfer to the fluid insulation system. This heat transfer process is performed via natural convection or with the assistance of pumps. The fluid insulation system is coolest at the bottom of the tank and extracts heat as it is directed up through the active part. At the top of the transformer, the fluid insulation is at its highest temperature where it then exits the main tank and enters external heat exchangers which can be radiators or water coolers. The fluid insulation sinks to the bottom of the heat exchangers as it cools and is returned into the bottom of the tank. Over the history of power transformers, several different insulating fluids have emerged and subsided. For this topic, it is good to understand some of these and why they have continued to be used or have been removed.

Naphthenic based oils have been used in transformers since as early as 1900. These fluids provide excellent heat transfer and electrical insulation; however, their ignition temperature is close to the maximum operating temperature of a power transformer. Where flammable oils were not acceptable, products like Askarel and Pyranol, which are polychlorinated biphenyls (PCBs) based, were used from the mid-1930s to 1970s [5]. With the Toxic Substances Control Act of 1976, the U.S. banned PCB based fluids due to environmental concerns. Tetrachloroethylene was introduced in 1980 by Westinghouse as a substitute, but due to the likeness to the PCB based fluids that had come before and the burden they presented once banned, the industry shied away from this fluid. Instead, silicone-based fluids took the role as the less flammable fluid of choice. Although silicones have great electrical properties, it can produce formaldehyde at high temperatures which can irritate skin and respiratory systems as well as other harmful effects on animals and humans [6]. As these fluid developments continued, the industry identified key elements for an insulating fluid: electrical insulation, chemical stability, fire resistance, water solubility, environmentally friendly, and thermal conductivity.

Due to the nature of facilities within the Bureau of Reclamation and the uniqueness of application, the focus of this paper will be specific to four insulating fluids: mineral oil, natural ester fluid, synthetic ester fluid, and SF_6 gas.

Mineral Oil

Naphthenic oil, most commonly known as transformer mineral oil, has been used since the early 1900s. This fluid comes from refined crude oil. This fluid has the longest track record of performance in power transformers. The electrical insulation properties and thermal conductivity are outstanding. The maintenance and diagnostics are well understood, and the flammability is accepted and accounted for with fire protection measures. This petroleum-based fluid comes from a limited natural resource, is not biodegradable, and has low moisture acceptance.

Natural Ester Fluid

The main goal of natural ester fluid is to provide a renewable source from which to produce the fluid. This vegetable-based fluid typically comes from seed oil and contains saturated and unsaturated fatty acids. This fluid has been used in power transformers since the early 2000s. International standards specific to this fluid have been developed and released to the industry. While the maintenance and diagnostics are understood, long-term data is still being gathered to support theoretical assumptions. This fluid is biodegradable and has a very high resistance to fire; however, the oxidation and pour point properties restrict this fluid to be used in sealed type transformers and not exposed to continuous cold weather outage times.

Synthetic Ester Fluid

Although coming from raw materials, synthetic ester fluid is manufactured to alter the properties of the fluid to best fit the application of transformer insulating fluid. Its first use in a power transformer was in 1999. The maintenance and diagnostics are understood; however long-term data is still being gathered to support theoretical assumptions. This fluid is manufactured to be biodegradable, have a high resistance to fire, excellent oxidation stability, and a low pour point temperature. This fluid can be used in all types of power transformers without concerns of adverse effects.

Sulfur Hexafluoride

Investigated as an alternate insulating fluid for transformers in the 1940s, Sulfur hexafluoride (SF_6) was found to be an excellent electrical insulation fluid, but high costs ended research in the U.S. Due to high population densities, Japan continued research on the medium and installed the first gas-insulated transformer in 1967. Currently, there are over 350 transformers installed worldwide using SF_6 insulation with the largest at 400-megavolt amperes, 330-kilovolts [7]. This fluid is nonflammable, requires no secondary containment or fire protection, and uses similar material as a liquid filled transformer. However, it is listed as a greenhouse gas due to its extremely high global warming potential. The maintenance and diagnostics are understood with similar techniques to liquid filled transformers.

Key Characteristics

Throughout the history of power transformers, the characteristics of a dielectric fluid have been refined. Although petroleum-based oils have provided predictable monitoring values and excellent thermal conductivity, their fire potential, environmental impact, and water solubility concerns have pushed the development of new fluids. With respect to the highlighted fluids of this paper, key characteristics include: fire safety, environmental impact, moisture saturation, electrical breakdown voltage, oxidation resistance, pour point temperature, thermal conductivity, and high temperature operating performance.

Fire Safety

Fire safety concerns are applicable for any energy-based equipment and although power transformer fires are extremely rare (1 fire in 1000 in-service transformers per year), the extent of damage can be catastrophic [8]. Specific to the ignition of the insulating fluid of a power transformer, there are two key elements to address: flash point and fire point. The flash point of an insulating fluid is defined by the temperature to which the fluid is heated that will produce an ignitable air mixture. A fluid's fire point is defined as the temperature at which enough fumes are produced to be ignited and continue to burn after the ignition source is removed. These values are important when considering that a transformer can operate up to 65-degrees C above ambient temperature during full load conditions and are frequently running with a top fluid temperature of 80-degrees C rise. These conditions put mineral oil insulation systems at risk for ignition. High temperature insulating fluids have such a high margin from operating temperature to flash point, it is near impossible to ignite these fluids.

Although flash and fire points are significant discussion points, it is not the only topic for fire safety. Hypothetically, if a fire was to occur, first the fluid must be heated to a temperature which would allow for a fire to start, then this temperature would have to be generalized (not in a single location) to sustain a fire, and finally how much energy does the fluid present to fuel a fire. To reach a fluids fire point, the mass of the fluid must be heated. For ester fluids with high fire points, this energy has been shown to be up to three times the amount of mineral oil [9]. If this amount of energy was available and a fire started, what would be the damage? To get a generalization of this, the low heat value can be analyzed. The low heat value is a way to represent the amount of energy available to a fire; the lower the number, the less available energy.

Table 2 - Fire Safety Properties

Insulating Fluid	Flash Point (°C)[1]	Fire Point (°C)[1]	Energy to Reach Fire Point (MJ)[2]	Low Heat Value (MJ/kg)[2]
Mineral Oil	145	160	147	46
Natural Ester	330	360	476	37.5
Synthetic Ester	275	316	430	31.6
SF_6	N/A	N/A	N/A	N/A
[1]: Based on [1] [2]: Based on [9]				

Many fire safety tests are performed specifically with the fluid involved and not in a practical application for power transformers. Generally, a transformer can be involved in a fire via two methods. The first being that a fire is started outside of the transformer which if the tank does not rupture there is a very slim chance the fluid would be involved in the fire. This circumstance can be ignored for the purpose of this paper. The second is during the situation in which the transformer has an internal fault and the fluid exits the tank and is ignited. To rupture a transformer tank, high pressures must be experienced inside due to fault conditions.

During an internal fault, local temperatures can cause the physical state of the fluid to change. Liquid insulation changes into a gaseous state which increases the pressure substantially. This causes a pressure wave to occur which will reverberate in the tank until equalized. If the tank cannot withstand the increase in pressure during this occurrence, the tank will rupture. A key thing to note here is that SF_6 is already in a gaseous state and therefore the increase in tank pressure is minuscule compared to fluid insulation systems. With the proper electrical protection systems in place, it is almost impossible to rupture a SF_6 transformer tank.

During research investigations no data was found showing a sustained ester or SF_6 fluid transformer fire. Appendix A – Fire Testing shows test methods performed by the Technical Service Center of the Bureau of Reclamation to better understand ester fluid's fire resistance properties. In summary, it was found that natural ester fluids are self-extinguishing and synthetic ester fluids would perform the same.

Environmental Impact

With respect to the environment, fluid insulation systems have two concerning topics. The first is how the insulating fluid is manufactured. Does it use renewable or limited resources? The global transformer market has seen a steady increase in manufacturing since the 1990s and with many forecasts showing increased electrical generation capacity, fluid insulation systems will be in high demand. In addition, aging infrastructure and emerging country connectivity will also increase the need for manufacturing. With these projected demands, petroleum-based oil could experience a major shortage as early as the middle of the twenty first century [2] [5]. Natural ester fluids are produced from vegetable oils which are renewable and readily available. Synthetic esters are produced from organic compounds and alcohols, both of which are readily available resources. SF_6 comes from raw materials such as sulfur, fluorine, bromine, and cobalt fluoride. Although available, these materials are hazardous and come with a high cost due to the compound manufacturing process [10].

The second topic is the impact on the environment if the insulating fluid is released from the transformer via spill or catastrophic failure. Insulating fluids are designed to have a strong chemical bond to resist breakdown while in operation, yet when released into the environment, this strong bond can be harmful. The higher the biodegradability, the less of an impact these fluids would have on the environment. The Environmental Protection Agency (EPA) and other governing bodies have established testing procedures for the breakdown of fluids into carbon dioxide. This decaying process occurs through the action of living organisms, sunlight, and water. To be considered “inherently biodegradable,” 20-60% of a substance must break down naturally within a 28-day period; additionally, a substance is considered “readily biodegradable” or “ultimately biodegradable” when 60-100% is broken down within the 28-day period [11]. While mineral oil and other petroleum-based fluids are not biodegradable, the vegetable based natural ester and acid/alcohol based synthetic ester fluids are listed as “readily biodegradable.” SF_6 is not a liquid and, when released into the environment, does not affect waterways and soils as much as the atmosphere. SF_6 is a listed greenhouse gas that has 23,900 times more global warming potential than CO_2; however, due to low amounts in production, the global warming impact is estimated at 0.2% [12]. Due to this, regulations are in place on SF_6 to prevent harming the environment.

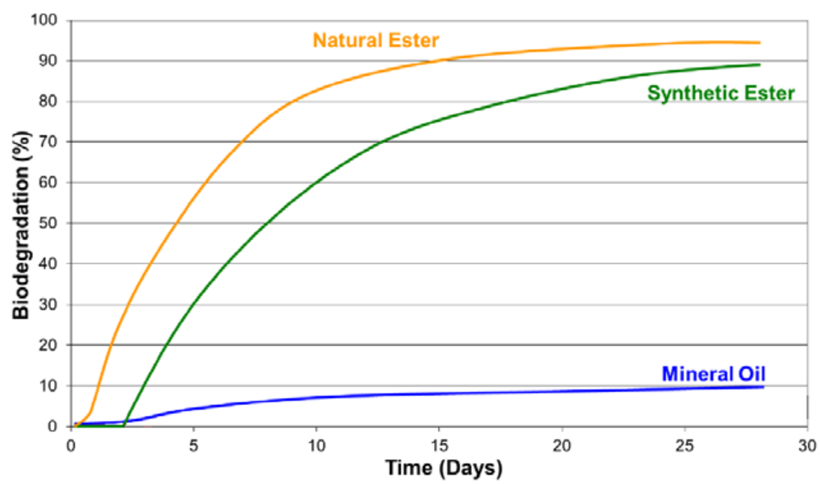

Figure 4 - Biodegradation Levels of Insulating Fluids [13]

Specific to environmental impact is aquatic reactions to a release of fluids into waterways near hydroelectric power plants. Some countries such as Germany have implemented a water hazard class which represents the damage to waterways and range from 1, low hazard, to 3, high hazard. Mineral oil has a classification of ‘high hazard’ while natural ester and synthetic ester have a classification of ‘low hazard’ [14]. Appendix B – Toxicity Testing shows test methods and results of aquatic toxicity tests performed by the Technical Service Center of the Bureau of Reclamation. In summary, it was found that natural and synthetic ester fluids, even at high concentrations, do not kill fish.

Moisture Saturation

One of the main purposes of the fluid insulation system is to provide electrical insulation to the active part. When moisture or other contaminants enter a transformer, they lower the dielectric strength of the fluid which leads to deterioration of the solid insulation system and ultimately reduces the life of the transformer. External water sources are not the only issue on this topic. As the cellulose paper in a transformer is aged, it has a water byproduct, as well as oxides and furans, and thus internal moisture is increased over a normal life cycle. This internal moisture is constantly exchanged between the solid and fluid insulation as temperature changes; higher temperatures allow more moisture to be dissolved into the fluid insulation which effectively ‘dries out’ the solid insulation while lower temperatures reduce the amount of moisture that can be dissolved into the fluid insulation which pushes moisture into the solid insulation. As a transformer reaches a certain moisture saturation level, it must be deenergized, so the moisture can be extracted from the insulation system. These outages are costly for a power generation station. Moisture extraction is difficult to perform due to most of the moisture residing in the solid insulation during an outage.

Each fluid insulation has a different relative saturation (RS) level. RS is the ratio of actual water content to the maximum water content that fluid can hold at a certain temperature. Once the water content in parts per million (ppm) reaches the maximum water content of the fluid, liquid water is formed in the transformer; also referred to as ‘free water’. Mineral oil and water are immiscible and thus mineral oil has a very low ppm allowance of water. Conversely, ester fluids act as a magnet to water molecules by forming a weak bond, called a hydrogen bond, where the water molecule is captured [15].

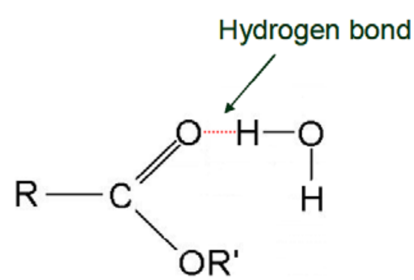

Figure 5 - Ester Fluid Hydrogen Bond with Water [13]

This bonding allows ester fluids to have a much higher relative saturation level. With respect to SF_6 insulated transformers, there is not a saturation limit because there is no water present. This is due to the internal pressure of the gas preventing the ingress of water as well as the solid insulation using a different material than a cellulose-based one. More details on this topic can be found in the Transformer Designs section.

Table 3 - Saturation Limits for Fluid Insulation

Insulating Fluid	Saturation Limit at 20°C (ppm)[1]	Saturation Limit at 60°C (ppm)
Mineral Oil	55	207
Natural Ester	1100	1900
Synthetic Ester	2700	4500
SF_6	N/A	N/A
[1]: Based on [16]		

Electrical Breakdown Voltage

Dielectric breakdown voltage of fluid insulating systems is one of the most important characteristics for a power transformer. Breakdown occurs when the insulating fluid reaches a voltage in which the fluid becomes conductive. At these voltage levels, free electrons build and cause a collapse of the insulating material. While under constant electrical stresses, the insulation system must be able to handle transient voltage stresses without failure. In fluids, it is difficult to understand the conditions that occur right before electrical breakdown happens. This topic of pre-breakdown phenomena, known as streamers, has differing results between testing with uniform versus non-uniform electrical fields. A transformer is manufactured to remove sharp points to reduce losses and areas of higher electrical stresses, which is best represented by a uniform electrical field [17]. To simulate this circumstance, prescribed conditions are established using a two-electrode method for testing.

Breakdown voltage of insulating fluids can be affected by voids in the fluid. These voids could be due to contamination such as particulates, water, or gas bubbles produced during high voltage electrical testing in liquid insulation, or impurities and low-pressure levels in gas insulation. Particulates can be controlled with sealed tank transformer designs, and the buildup of gas bubbles during testing can be handled as discussed further in Factory Testing Procedures. Breakdown voltage correlates to moisture content in liquid insulation systems, as shown in Figure 6. As moisture content increases in a liquid, the electrical insulation value decreases, which reduces the breakdown voltage. Although breakdown voltage levels of the three liquids are similar with limited moisture content, mineral oil drastically drops off when water contaminates the liquid. A well-maintained transformer will be free of large amounts of moisture and thus ‘free water’ is typically is not a concern. Due to ester fluids having a higher moisture solubility, they will require less drying of the liquid over the life of the transformer.

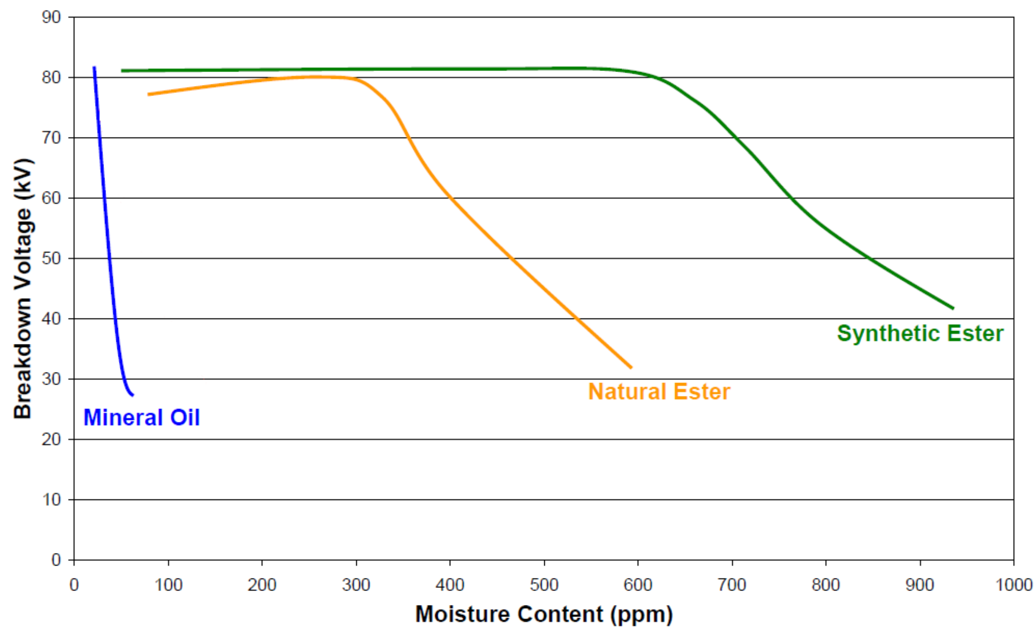

Figure 6 - Breakdown Voltage with Respect to Water Content [13]

As discussed previously in the Moisture Saturation section, there is no water present in SF_6 insulated transformers. However, the purity of the gas and the pressure directly affects the breakdown voltage levels. SF_6 has defined electrical properties that are maintained based on pressure; as the pressure increases, the breakdown voltage increases. Due to this, the transformer tank is designed differently, which is discussed further in Transformer Designs. SF_6 has excellent dielectric properties due to its ability to bind free electrons, hence preventing electron avalanches, which propagate to failures [18].

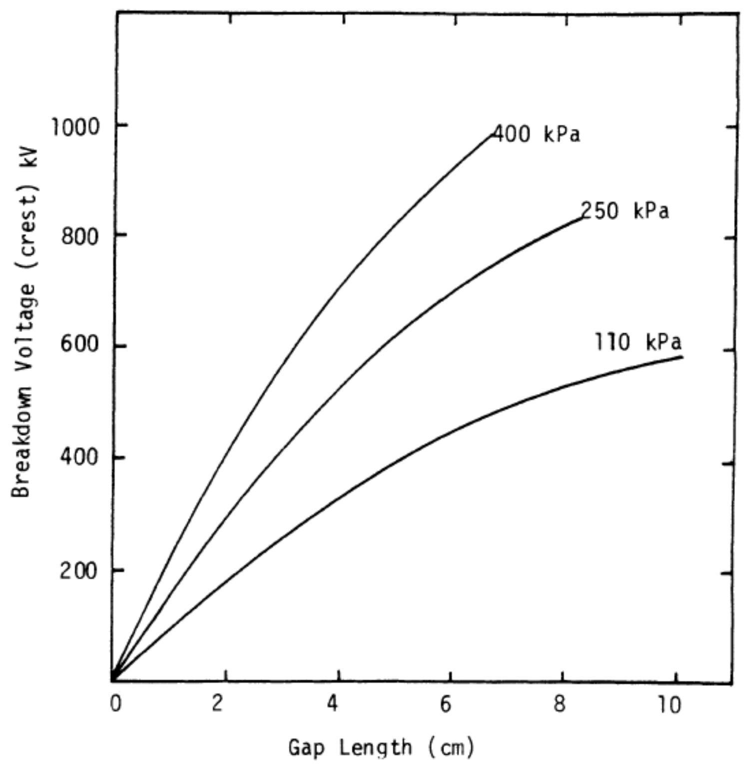

Figure 7 - SF_6 Breakdown Voltage with Respect to Pressure and Gap Distance [18]

With the dielectric breakdown voltage being highly dependent on quality of the fluid or the pressure of the gas, it is key to understand that this value will be different for fluids in containers or installed in a transformer due to the processing procedure to dry-out and degas the fluid. Table 4 shows the minimum acceptable values for the receipt of new insulating liquid in bulk containers.

Table 4 - Dielectric Breakdown Voltage in Bulk Containers [19] [20] [21]

Insulating Fluid	**Dielectric Breakdown at 1-mm gap (kV)**	**Dielectric Breakdown at 2-mm gap (kV)**
Mineral Oil	20	35
Natural Ester	20	35
Synthetic Ester	30	45

Once the liquid has gone through installation procedures, such as dry-out and filtering, the final dielectric breakdown voltage must be at or higher than the minimum values shown in Table 5.

Table 5 - Dielectric Breakdown Voltage in Electrical Equipment [19] [20]

Insulating Fluid	Dielectric Breakdown at 1-mm gap (kV)			Dielectric Breakdown at 2-mm gap (kV)		
	≤69	>69 & <230	≥230[1]	≤69	>69 & <230	≥230[1]
Mineral Oil	25	30	35	45	55	60
Natural Ester	25	30	35	45	52	60
Synthetic Ester	30	35	40	45	55	60
[1]: Note that additional values are provided for voltages between 230 and 345 but are not shown in this table for clarity purposes. Refer to the referenced materials for those values.						

For SF_6 insulation systems, transformers can be designed with two pressure levels at 20-degrees C: 0.14-megapascal read from a gauge (MPaG) for voltages at or below 139-kV and 0.43-MPaG for voltages above 139-kV [22]. In addition to dielectric voltage, the pressure of the gas is required for cooling purposes as discussed in Cooling Methods.

In liquid insulated transformers, the cellulose wrapped on the windings obtains its full electrical properties by soaking in the liquid insulation in a process called impregnation during manufacturing. Electrical stresses can be seen between the solid and fluid insulation when the permittivity of these materials is different. Permittivity indicates the ability of a material to polarize and gain electrical capacitance. The closer the permittivity of the two materials, the less electrical stress is seen in these areas. Ester fluids have a permittivity closer to that of the cellulose insulation which means the overall structural has a more consistent electrical field distribution. Ester fluids also have lower electrical stresses which pushes these stresses to the solid insulation. This is a benefit since the solid insulation is a stronger dielectric when properly impregnated with the insulating fluid. However, this also means that the peak stresses effect the fluid greater and thus adjustments in design clearances are needed [13].

Oxidation Resistance

Although a power transformer is one of the most reliable pieces of electrical equipment in a power generation plant, it still requires maintenance which includes visual inspections, standard tests, and sometimes major repairs that require draining the insulating fluid. During instances that require the active part to be exposed to the environment, special care must be taken to reduce contamination. One key element that comes into play here is oxidation stability. Oxidation stability is the ability of a liquid to resist reactions with oxygen which would produce harmful byproducts in a transformer, such as viscosity increases (thickening), sludge, varnish, and acids, which would degrade the overall insulation system. This chemical reaction is accelerated with high temperatures, water, acids, and catalysts such as copper. The higher the stability, the better the overall life of the transformer.

Standardized tests rate oxidation stability based on time during an accelerated aging condition in controlled environment conditions. While these tests do not accurately reflect conditions inside of a transformer, they do provide characteristics of the fluid during times where the active part is exposed to the environment. For the three insulating liquids in this report, synthetic ester fluids provide the best oxidation stability with a time of 400-minutes or more. Naphthenic based mineral oil has an excellent oxidation stability when in a controlled state; however, due to its low moisture allowance, the oxidation is accelerated once past inception. Mineral oil has a time of approximately 300-minutes. Natural esters have a poor oxidation stability when a thin film is exposed and record a time less than 40-minutes. The standardized tests do not accurately reflect the conditions in a transformer and should only be used as information [23].

Knowing and understanding the oxidation stability of each liquid allows users to put precautionary measures into place to reduce the potential for oxidation to occur. To limit the possibility of oxidation for natural ester fluid transformers, it is recommended for the transformer to be of the sealed type; either sealed conservator or sealed-tank type (nitrogen blanket). Additionally, exposure of the active part after impregnation of the cellulose paper should be limited to no more than 32-hours at a time at the manufacturer factory and as described in Assembly.

Pour Point Temperature

One of the major functions of an insulating fluid is thermal conductivity: the ability to remove heat from the active part of the transformer. To do this effectively, the fluid needs to be a temperature that increases the thermal delta between fluid and active part. Flow of the fluid allows a constant thermal delta and increases the rate of heat transfer via convection. In cold weather environments, insulating fluids increase viscosity and thus reduce the thermal conductivity of the overall system. Although reduced, thermal conduction still occurs with no flow of the insulating fluid.

Pour point is defined as the lowest temperature at which a fluid is observed to flow. The insulating fluids used in power transformers do not make an immediate change from fluid to solid at a defined temperature, but rather experience a thickening and gelling effect. During de-energization, a transformer may take days or weeks to reach equilibrium temperatures with the environment due to their mass and thermal time constant. Daily low temperatures are not of a concern, but daily average temperatures are the key factor when looking at realistic environmental data. In the continental U.S., less than 1% experiences temperatures below -25-degrees C for a prolonged, more than 3-day, period [24].

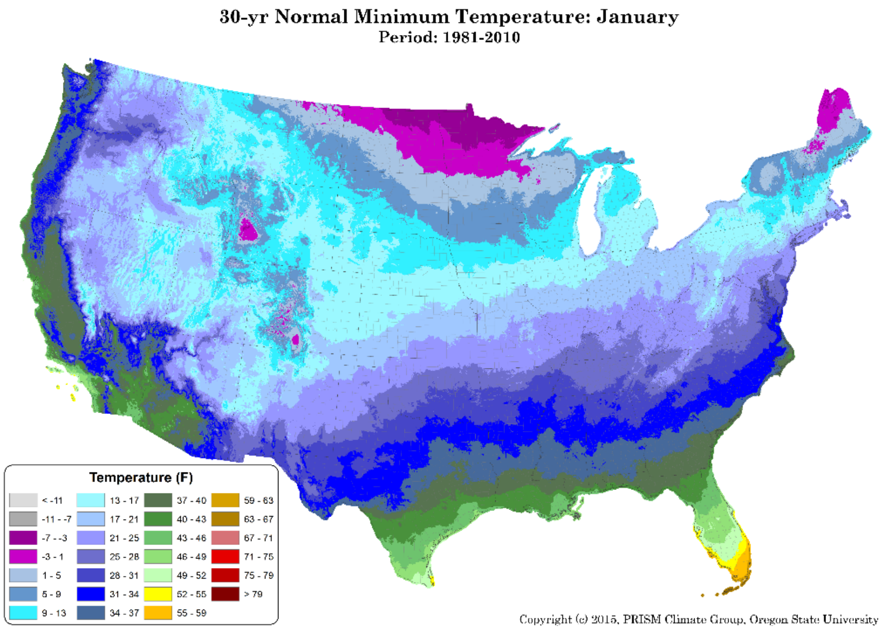

Figure 8 - Minimum Average Daily Temperatures in U.S. [25]

These concerns are valid when the transformer is de-energized over a prolonged period. Even under no-load conditions, the internal losses of a transformer will generate enough heat to prevent gelling of any fluid. With respect to higher viscosities of the fluid and potential gelling, two topics become a concern: dielectric strength and moving apparatuses. As temperature drops on mineral oil fluids, the water saturation level also drops which increases the potential of forming 'free water' in the transformer. Even though mineral oil has a low pour point temperature, cold start procedures are required to prevent a fault due to high moisture levels in the insulating fluid.

Table 6 - Pour Point Temperatures of Liquid Insulation [19] [20] [21]

Insulating Fluid	**Pour Point (°C)**
Mineral Oil	-40
Natural Ester	-10
Synthetic Ester	-45

Due to the relative saturation being higher in ester fluids, the dielectric strength of the fluid is not reduced due to cold temperatures. These fluids may thicken and possibly gel in extreme conditions; however, the dielectric properties remain intact. Although this allows the transformer to remain dielectrically stable, moving apparatuses are a concern. If pumps are used for cooling, these pumps must be off during cold start situations until the fluid has warmed up enough to allow for flow within the pumps' operating range.

Cold temperature situations are of concern no matter the insulating fluid installed. Thickening of any fluid not only impacts the cooling system and possibly dielectric properties, but also limits diagnostics, such as dissolved gas monitoring. Thickening of the fluid reduces the ability for the dissolved gasses to be available at the sampling port. Outside of liquid insulating systems, cold temperature also introduces issues in gas insulation. SF_6 has a liquefaction pressure around 0.52MPa at -30-degrees C. Due to this relatively high liquefaction, SF_6 must be kept at a higher temperature when installed in a power transformer.

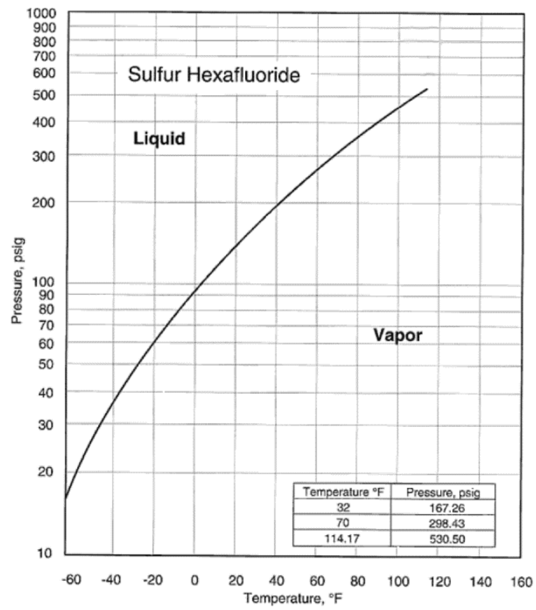

Figure 9 - Liquefaction Curve of SF_6 Based on Temperature and Pressure [26]

During the replacement of any GSU transformer, the operations procedures should include cold start measures that are specific to the location and insulating fluid being used.

Thermal Conductivity

Rivaling dielectric strength as one of the most important characteristics of an insulating fluid for a power transformer is the thermal conductivity, or better known as the cooling property. During the design of a transformer, thermal models are produced showing temperature rise characteristics, hot spot locations, and fluid flow. This modeling helps to produce items like correct cooling channels, pipe diameters, and pump characteristics when applicable.

The properties of the insulating fluid drive these designs as viscosity, thermal expansion, heat capacity, thermal conductivity, specific heat, and relative density are different in each type of fluid. Typically, natural ester fluid is more viscous than synthetic ester fluid, while mineral oil is less viscous than both esters. SF_6, being a gas, does not have a viscosity value that is comparable to the liquids, but it is key to note that temperature has an inverse effect on gas viscosity; the increase in pressure of gas increases the viscosity as well. This increase in viscosity increases the heat transfer ability which is necessary for the transformer design. Additionally, the gas must be passed constantly through the active part to allow for the proper heat transfer.

Although this paper will not go into the specifics of each property listed above, it is key to know that each of them have differing features that govern the thermal design of a transformer. A transformer may be designed to properly extract the heat from the active part using any of the insulating fluids addressed in this paper; however, that specific design may not be applicable to a different type of fluid. This is the reason that retrofilling is not applicable to all transformers.

High Temperature Operation

The heat generation of a transformer is important for the impact it has on the insulation system, which directly equates to the transformer life. Based on years of in-service data, transformer standards have been written such that the insulation system ages at a normal rate when operated at a standard temperature rise and hot spot. This is due to the understanding of how the insulation system ages or deteriorates as a function of temperature and time. The thermal performance of different materials changes with respect to their thermal aging limits. This is defined by a thermal class of the material and given in international standards such as IEEE C57.154 and IEC 60085.

As previously discussed, insulation systems are made of a fluid insulation and a solid insulation. These two subparts can have different thermal classes which contribute to the thermal class of the overall system. Additionally, enamels that hold the separate strands of copper conductors together and pressboard that provides internal structure to the transformer may have separate thermal classes.

Table 7 – Typical Thermal Classification of Solid Insulating Materials

Material	Thermal Class [1, 2]	Hottest Spot Temperature (°C)	Typical Use
Cellulose Paper	105	95	Winding insulation
Pressboard Cellulose Based[3]	105[2]	95	Internal structure
Thermally Upgraded Cellulose Paper	120	110	Winding insulation
Polyethylene Terephthalate (PET) Film	120[4]	110	Winding insulation
Polyphenylene (PPS)	155	145	Winding insulation
Aramid	220	210	Winding insulation
Pressboard Aramid Base	220	210	Internal structure

[1]: Based on IEEE C57.154-2012 and IEC 60076-14-2013 except for PET.
[2]: All measurements taken in air.
[3]: Classification is based on air. When immersed in liquid insulation, the thermal class is 120.
[4]: Based on testing as defined in IEEE C57.100.

These thermal classifications define the hottest spot temperature as a point at which the material is expected to provide a normal transformer life. These materials may be used in combination to provide the optimal thermal and economic design of the transformer. While many signs can help determine the aging of a transformer, the key elements are water formation and organic acid buildup. Depending on the insulating fluid and its relative saturation, water formation can be absorbed and reduce the deterioration of the solid insulation. As previously discussed, the amount of water that can be dissolved in the insulating fluid depends on temperature and aging of the fluid. As the temperature increases, the fluid can absorb more water. The upper temperature limits of these fluids are limited by the flash and fire points from the discussion in Fire Safety. When an insulating fluid can be operated at higher temperatures, it can absorb more water and effectively reduce the aging effect on the solid insulation.

With respect to the topic of this paper, using an insulating fluid with a higher operating temperature has two potential effects on a transformer. The first is extended transformer life. By absorbing more water content at traditional operating temperatures, the insulating fluid reduces the aging effect of the solid insulation which extends the overall life of the system. In accelerated tests it has been shown that the life expectancy of cellulose solid insulation in natural ester fluid is extended by five times normal life when compared to being in mineral oil fluid insulation [27].

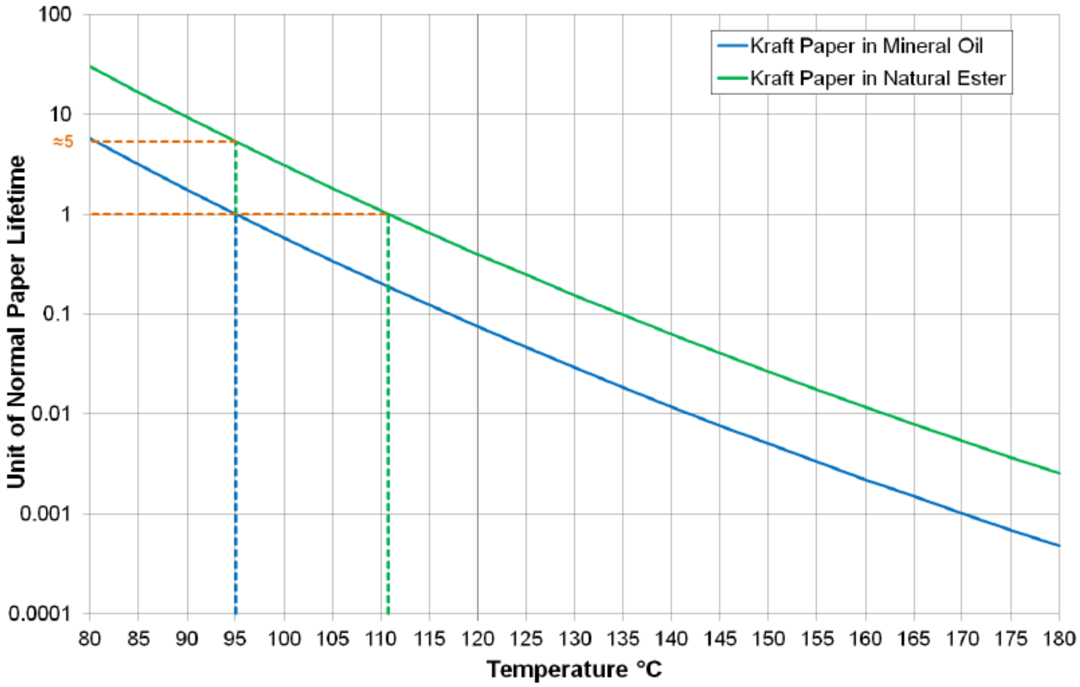

Figure 10 - Cellulose Paper Life Expectancy

Additionally, thermally upgraded cellulose paper has a life expectancy of seven times more than when used in mineral oil [27].

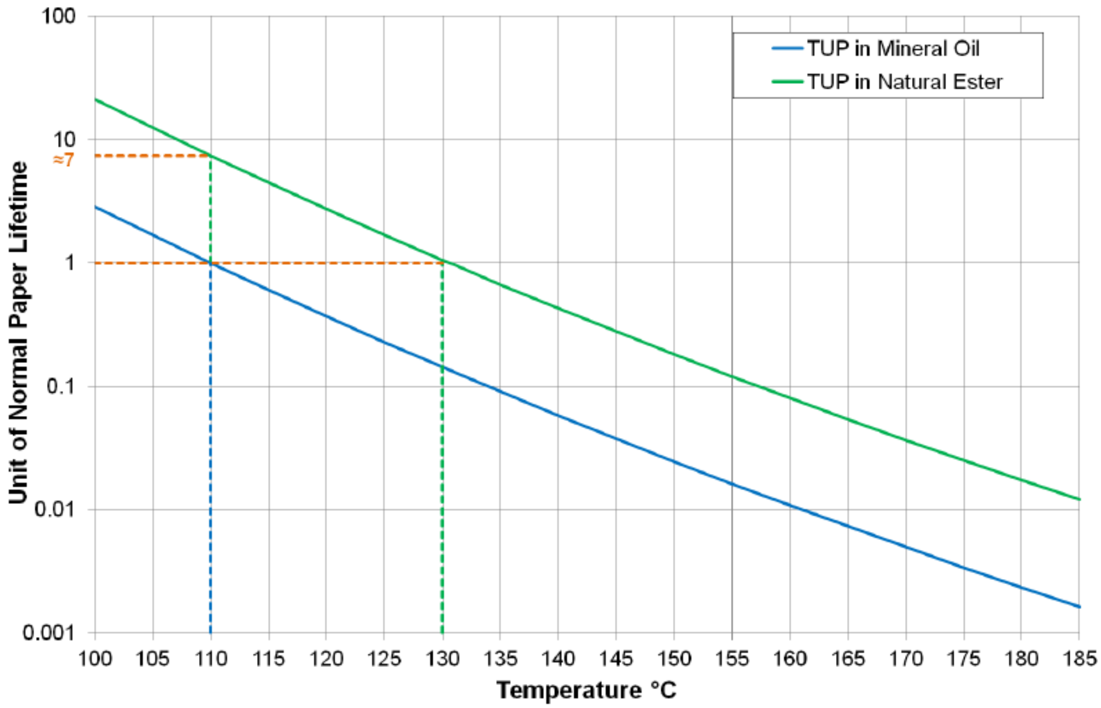

Figure 11 - Thermally Upgraded Cellulose Paper (TUP) Life Expectancy

Understanding that water content is the leading reason for this effect, in theory, we can assume synthetic ester fluid would produce the same effects, if not greater, due to its ability to hold more moisture. If we use these graphs to compare operating temperatures during a life expectancy of 1, we see that cellulose may be operated at 110-degrees C and thermally upgraded cellulose may be operated at 130-degrees C. These higher operating temperatures allow for more thermal capacity of the transformer; essentially meaning the transformer has a higher power rating. Although these values are based on accelerated tests performed in controlled environments and cannot be taken as operating criteria values, this information is thorough enough that international standards have produced higher temperature operating criteria when using high temperature materials. These materials may be used in a combination of ways to optimize the economic and thermal design of the transformer. Table 8 summarizes the different insulation system combinations.

Table 8 - Insulation System Combinations [27]

C: Conventional H: High-Temperature		Conventional System	Hybrid System			High Temperature System[2]
			Semi-hybrid	Mixed Hybrid	Full Hybrid	
Type of Insulating Component[1]	Liquid	C or H	C or H	C or H	C or H	H
	On Conductor	C	H	C and H	H	H
	Spacers	C	C	C and H	H	H
	Barrier	C	C	C	C	H
Insulating Component Application Temperature	Top Liquid Rise	C	C	C	C	H
	Average Winding Rise	C	H	C	H	H
	Hot-Spot Winding Rise	C	H	H	H	H

[1]: Only basic components are shown.
[2]: Some conventional insulation is acceptable in areas where thermal mapping shows conventional temperatures are maintained.

Conventional liquid insulation is typically mineral oil and conventional solid type insulation is cellulose paper. Both natural ester fluid and synthetic ester fluid are considered high-temperature. With these defined systems, transformers may be operated at higher temperatures and maintain the same life expectancy. While conventional systems have an average winding temperature rise of 65-degrees C, hybrid systems can range from 75-degrees to 105-degrees C rise, and high-temperature systems can range from 85-degrees to 125-degrees C depending on the type of solid insulation used [27].

By allowing a transformer to operate at higher temperatures, the space necessary for cooling the active part can be reduced which reduces the transformer's overall footprint. This space reduction can be monumental for locations with existing restrictions.

Transformer Designs

Understanding the key characteristics of power transformers brings the impacts of differing insulating fluids to life. From the impregnation of the winding insulation to the width and frequency of the cooling channels, each transformer is designed to maximize efficiency while limiting costs. Although the insulating fluid will have an impact on each chosen component, this section will only discuss select topics with respect to the design.

Design Differences

Transformers come in three major components: the active part (core and coils), the insulating fluid, and the containment of both (tank). The interdependence of these parts requires that each transformer design consider the insulating fluid being used. Not every type of transformer is suited for each fluid. To avoid oxidization issues, natural ester fluid is not recommended to be installed in a free breather transformer, while SF_6 insulation requires a pressure vessel for the tank. These decisions also impact the exterior components such as bushings which use an electrical insulating medium as well. For a transformer that is using an alternate insulating fluid due to fire protection or environmental concerns, the bushings should be designed to follow this intent by not using mineral oil, but rather using resin impregnated or other types.

Using alternate insulating fluids opens possibilities for transformers to operate at higher temperatures. By using a high temperature insulating fluid, designers have more flexibility to strategically place different insulation materials in areas to maximize the economics of the transformer.

Cooling Methods

Due to cooling being one of the major tasks of the insulating fluid, it is clear that cooling methods are greatly affected by the type of insulating fluid used. For more viscous fluids, larger cooling channels are used in the windings and core stacking process which is shown in Manufacturing. Additionally, pumps, if used, must be sized appropriately to handle the thicker fluid.

As explained in Thermal Conductivity, gas-insulated transformers require the gas to be pressurized and constantly passed through the active part of the transformer to extract heat. This type of cooling method requires large blowers or fans to be placed in the gas channel.

Figure 12 - Gas Blowers on a Gas-insulated Transformer

Fabrication Processes

As detailed in Manufacturing, building a power transformer is a meticulous process. The schedule at a transformer manufacturing facility is compressed as much as possible for the company to be competitive around the globe. These processes have been refined over many years with mineral oil as the insulating fluid. When changing the insulating fluid, these processes must be modified to obtain the proper outcome of the power transformer.

Increasing cooling channels requires the vertical or horizontal winding machine to have different spacers placed. Also, the winding is slightly enlarged which effects clearance distances within the transformer. Increasing cooling channels is not the only obstacles faced with this change. Once the windings are completed, they are passed through a drying oven where moisture is extracted and, in the case of liquid insulation, the windings are impregnated with the insulating fluid. When using mineral oil, this process can take approximately 24 hours. Due to the difference in properties, ester fluids take approximately 3 days to complete this same process.

When a transformer uses gas as the insulating fluid, cellulose cannot be used as the insulating material for the windings; rather, gas-insulated transformers use a material called Polyethylene Terephthalate (PET) film or polyphenylene sulfide (PPS) film. Aramid or other high temperature insulating material is used for blocking or other means. These materials do not require impregnation but do go through the same dry-out procedure. The tank design for gas-insulated transformers limits the number of penetrations to reduce the potential for leaks. This means that additional protection and monitoring devices, such as fiber optic temperature and partial discharge monitoring that require tank penetrations, have potential draw backs if designed into the transformer.

Factory Testing Procedures

The details in the manufacturing process are fully vindicated when a transformer passes factory testing. In each facility, the testing bay is a bottle neck for transformer manufacturers. In many companies, the testing bay has multiple shifts of people that work around the clock to pass transformers through. Most of the transformer factory tests are the same regardless of insulating fluid type; however, some of the dielectric tests do require some modification, which can further impact the schedule.

As a result of the insulating fluids' Electrical Breakdown Voltage and viscosity, each insulating fluid experiences different characteristics with respect to breakdown voltage. Clearances are designed into the transformer to prevent failures due to electrical stresses. During high voltage testing, a transformer's insulation system is tested for weaknesses that may result in a future failure. These tests expose the transformer to very high local electrical fields which dissipate energy into the transformer causing localized gas bubbles. Once the gas bubbles travel away from the windings in which they were developed, the insulation system may be tested again. In impulse testing, a transformer is exposed to a series of tests that represent lightning and switching surges. Due to the viscosity of the fluid in use, these tests may require additional rest time to allow the gas bubbles to escape from areas of high stress. It is key to note that ester fluids require a minimum rest time of 15-minutes in addition to traditional rest times required for mineral oil [19]. Without this additional rest time, a transformer can fail impulse testing. For high BIL level transformers, more rest time may be required.

Transportation

The movement of a power transformer is a demanding feat that requires trained and experienced personnel to reduce the risks of damage. Many transportation companies are not knowledgeable of the differences in insulating fluids and cautions that should be taken in the planning and execution for moving these pieces of equipment. Traditionally, large transformers are not shipped with the insulating fluid but rather filled with a pressurized gas to prevent ingress of contaminates. The insulating fluid adds weight to the shipment and is best installed at the site to reduce shipping costs and risks associated with moving the transformer with fluid installed. The bushings are also removed and replaced with 'shipping bushings' to reduce the overall size of the shipment.

This disassembly process takes place at the transformer manufacturer's facility under controlled conditions to prevent contamination of the active part. As the insulating fluid is drained and removed, the active part becomes exposed. In addition to normal contamination, duration of exposure to air becomes a factor when using natural ester fluid due to the oxidation stability properties as explained in Oxidation Resistance. With heat and oxygen combining to reduce the overall resistance, time limits should be employed for natural ester fluid transformers. It is recommended to have a maximum exposure of 32 hours. This duration of exposure is more than adequate to perform the disassembly process; however, it does require monitoring to make sure unnecessary exposure time is not experienced.

Once disassembly is complete and the transformer is sealed, the tank is filled with a pressurized gas to help keep contamination out during transportation. Typically, breathable dry air is used with a regulated air supply to maintain positive pressure. This is the case with all insulating fluid types except for natural ester fluid. Once again due to the oxidation resistance properties, transformers using natural ester fluid should require the transformer to be filled with dry nitrogen instead of air. When shipping with nitrogen, labels are required to alert personnel of the conditions prior to entering the tank. Evacuation of the nitrogen is required prior to reassembly or internal inspections.

Installation

The duration from when a power transformer arrives on site to the time it is ready for energization can be two weeks or more depending on the project. Once the transformer arrives on site, it must be assembled, fluid filled, and field tested prior to energization. Each of these steps requires trained personnel and the choice of insulating fluid can affect these procedures.

Assembly

After a transformer has arrived on site and passed frequency response analysis testing, the unit must be purged of the pressurized gas and filled with breathable air. As explained in Transportation, the duration for assembly and exposure to oxygen must be closely monitored for natural ester fluid transformers in comparison to the other insulating fluid types. Typically, on-site assembly does not occur in a controlled environment and requires the schedule to be based on fair weather conditions. To limit the risk potential for oxidation of natural ester fluid, it is recommended to have to the tank open for no more than 32-hours during assembly and fluid filling. For insulating fluids other than natural ester fluid, the assembly process is unchanged.

Fluid Filling

During vacuum filling, the type of insulating fluid can affect the degassing and dry out procedures. Fluid filling a transformer with gas insulation is slightly different than liquid insulation, although each type follows a degassing and dry out process. Vacuum levels follow international standards for percent moisture and wait times and will not be discussed here. The SF_6 for gas-insulated transformers arrives in cylinders typical of installations in other electrical equipment. Once the transformer is ready to receive the insulating fluid, the cylinders are connected to the tank via gas handling equipment and the gas is transferred into the transformer. During the transfer process, the purity of the gas is checked and verified to be higher than 99% SF_6 for electrical technical grade gas. Once the gas transfer is complete, a sample is taken to verify the purity. If this purity is not met, the gas is evacuated and filtered until meeting these levels.

For liquid insulating fluid, a processing rig is used to degasify and dehydrate the fluid. A key thing to note for all types of insulating fluid is that the processing rig must be thoroughly flushed and cleaned prior to filling with the transformer insulating fluid. Although permissible, the high temperature properties of ester fluids are diminished if certain amounts of mineral oil are mixed in. While performing the degassing and dehydrating process, ester fluids may be heated to a higher value than mineral oil to help with extracting moisture. Mineral oil is typically heated to a temperature between 60 and 90-degrees C while ester fluids may be heated to a temperature between 60 and 100-degrees C [28] [19]. The hotter the insulating fluid, the easier it is to extract moisture.

As discussed in Moisture Saturation, ester fluids can hold much more water content than mineral oil. This should be noted when looking at test limits for the insulating fluid after processing. Values listed in international standards like IEEE C57.106 should only be used for mineral oil insulation. The appropriate standard must be consulted when installing an alternate insulating fluid.

Commissioning

Commissioning of a power transformer involves wiring checkout, device checks, field tests, and startup procedures. Although different protection devices are available for different insulating fluids in a transformer, the process of commissioning does not change. Depending on the fluid chosen, additional ancillary systems may need to be commissioned as well.

Operations

There are many properties to understand when discussing insulating fluids; however, all fluid insulating systems allow the transformer to perform its main objective. The alarm and trip signals that monitor these transformers are very similar with minor adjustments in alarm points. Yet, when discussing gas insulation, a key component must be discussed: cooling operations. Liquid insulation systems have excellent heat transfer ability due to their material density. For a gas-insulated transformer to have similar thermal capabilities, the gas must be pressurized and circulated constantly in the tank. To properly perform this, gas circulating fans are used in the heat exchange portion of the transformer to circulate the gas, which allows the heat to be extracted at a rate which will prevent damage to the active part. The internal losses of a transformer can produce enough heat to damage the solid insulation. Even during a no-load state, gas circulation must continue if the transformer is energized.

Start Up Procedures

Start-up procedures are similar for all insulating fluid types. Although Pour Point Temperature explains why cold start procedures are required, depending on the insulating fluid type, there are different reasons for this. Due to water saturation, ester fluids do not lose dielectric properties at lower temperatures like mineral oil; however, they will thicken and make the pumps inoperable. SF_6 gas could liquefy under extreme cold temperatures. For insulating fluids that thicken in cold temperatures, the cooling pumps should be turned off during startup and allow time for the mass of the fluid to warm. For temperatures below -20-degrees C, the transformer should be energized at no load for at least 2-hours and then slowly add load in 25% increments at least 30-minutes apart [28].

Retrofilling Fluids

With the realization of mineral oil's short comings in moisture tolerance, fire safety, and environmental concerns, one cost effective way to improve existing transformer installations is to replace the mineral oil with a high temperature fluid in a process referred to as retrofilling. Although retrofilling has many attractions, it is not applicable to all transformers. As explained throughout this paper, the insulating fluid type has impacts on design, manufacturing, and testing. Because of these differences, every transformer is not a candidate for a replacement of the fluid type. If retrofilling is a solution worth pursuing, the manufacturer of the transformer should be consulted, along with technical experts in the field of transformer design and testing to determine if the transformer's fluid can be changed without negative consequences.

Maintenance

A power transformer's life is estimated at 180,000-hours (20-years) based on continuous operation at full load, however the life on these pieces of equipment are based on temperature experienced during operations with mineral oil insulation [29]. Reclamation's operating criteria at many power plants allows for the average life of a mineral oil transformer to be estimated at 45-years [30]. These estimates are based on proper design, manufacturing, factory testing that is performed according to international standards, correct installation, and adequate maintenance over the transformer's lifespan. As discussed in High Temperature Operation, alternate insulating fluids have a substantial impact on a transformer's insulation system, which could increase their operating life significantly.

Understanding differences between insulating fluids does not stop at the design level but rather this knowledge must be used throughout the service life of a transformer. Many typical service and diagnostics tests have result ranges based on mineral oil fluid experiences. This section will highlight key maintenance tests that have different results and analysis techniques based on the insulating fluid of the transformer. It is important to state that this paper does not suffice for expert diagnostics and many times it is necessary to contact specialists with the proper knowledge for analysis.

Dissolved Gas Analysis Testing

A transformer's insulation system breaks down over time and releases gases as a byproduct during thermal and electrical disturbances. These gases can be extracted and analyzed to determine the life of the insulation system and help identify localized overheating, partial discharge, and electrical faults. This testing method of dissolved gas analysis (DGA) is very particular and typically requires a high frequency of testing to develop trending patterns over the life of a transformer. DGA is one of the most important tools to assess the life of a transformer and it is critical to understand the differences when looking at alternate insulating fluids. Mineral oil has been used in power transformers for more than a century and its limitations and diagnostics are well understood. Although this paper will not discuss DGA for mineral oil insulation systems, gassing results for mineral oil will be used as the basis for comparison in this section. Information on the gases developed and acceptable ranges in mineral oil can be found in international standards such as IEEE C57.104 and Reclamation's book on Transformers: Basics, Maintenance, and Diagnostics. Alternate insulating fluids do not have the same lineage and require more diagnostic analysis to be performed, however international standards have been developed to assist in these ventures.

Natural and Synthetic Ester Fluids

Due to ester fluids having limited in-service DGA data with minimal transformer failures, information has been developed based on accelerated laboratory tests to indicate normal operation, failure conditions, and trend patterns. The analysis of these fluid types should be performed by a trained professional and consulted with multiple experts in the field when making critical decisions. The types of gases generated in ester fluids are the same as mineral oil; however the ratios, rates of generation, and development causes can be very different [31].

- During electrical fault conditions where the fluid and volume are the same:
  - Natural ester fluid would produce ten times less fault gas when compared to mineral oil.
  - Synthetic ester fluid would produce similar amounts when compared to mineral oil.
- When exposed to thermal stresses, ester fluids generally produce two or more times more gas when compared to mineral oil.
- Carbon oxides are produced in higher quantities in ester fluids which could exceed amounts produced by solid insulation in the transformer. This could result in misinterpretation of the conditions inside of the transformer.
- Ethylene is produced in higher quantities at lower temperatures in ester fluids; however, at higher temperatures, the ethylene production is like mineral oil.
- Methane and ethane are produced in higher quantities at lower temperatures in ester fluids. In some high temperature ranges, methane and ethane are produced in similar quantities; this is different than mineral oil.

Differences in gassing results like shown above require the DGA to be interpreted differently than in a mineral oil transformer. Additionally, natural ester fluid is sensitive to sunlight and ultraviolet light from fluorescent lights therefore the procedures for sampling may need to be adjusted to limit contaminating the sample. International standards such as IEEE C57.155 and IEEE C57.147 should be used as reference material for understanding interpretation criteria and identifying acceptable gas ranges for a transformer with natural ester fluid.

SF_6 Gas

Although SF_6 is an insulating gas, the internal components of the transformer still produce gas byproducts during operations like other transformers. These gases can be extracted from the SF_6 using similar, but much simpler methods due to the gases being dissolved into the insulating gas. A gas detector tube can be used to quantify the elements, or a sample can be sent to a laboratory for gas chromatography extraction and analysis.

The byproducts for this type of transformer are completely different because of the difference in solid insulation (PET/PPS vs cellulose) and fluid insulation. PET/PPS is used to wrap the windings as explained in Design Differences for SF_6 insulated transformers and decomposition byproducts include carbon monoxide (CO), carbon dioxide (CO_2), acetaldehyde (CH_3CHO), dimethylacetamide ($CH_3C(O)N(CH_3)_2$), and methane (CH_4). Cellulose is still used for structural areas and produces byproducts CO, CO_2, CO_4, C_2H_4, and CH_4. SF_6 has decomposition byproducts like SF_4 which react with other elements to form sulfuryl fluoride (SO_2F_2), sulfur dioxide (SO_2), hydrogen fluoride (HF), carbon tetrafluoride (CF_4), and carbon hexafluoride (C_2F_6).

These decomposition elements provide the necessary information for assessing the condition of the transformer. The following provides some insight to diagnostics.

Table 9 - Decomposition Elements for SF_6 Transformer

Element	**Diagnostic**	**Effected Area**
HF	Discharge / Overheating	Coils / Insulation Fluid
SO_2	Discharge / Overheating	Coils / Core / Insulation Fluid
CO	Overheating	Cellulose breakdown
CH_3CHO	Overheating	PET/PPS breakdown

Site Conditions

Original construction of many facilities occurred during a time before environmental and fire protection concerns were closely examined. The GSU power transformer infrastructure is aging and replacements are occurring regularly. With these replacements, many facilities are faced with working within the means of their existing facilities while trying to figure out ways to meet the demands of current standards and codes. Many hydroelectric generating facilities have GSU power transformers located directly above waterways with little space between the power plant wall and the edge of the deck that drops to the tailrace.

Figure 13 - GSU Power Transformer Deck

This section will point out many obstacles faced by power generation facilities during the replacement of their power transformers and how the use of an alternate insulating fluid may alleviate or reduce the impact of these situations.

Location and Containment

No matter the location of a facility, the local and regional environment is always a concern. Most hydroelectric facilities have their GSU power transformers located near or above the waterway used to create electricity. These installations pose a great risk to the local environment if a spill or failure was to occur. If an insulating fluid was released, the impact to the regional environment, financial burden during cleanup, and future project considerations will be greatly affected. Federal regulations in the U.S. and many insurance providers list requirements for control and countermeasure plans for spills. Generally, these requirements include secondary containment systems to reduce the risk of contaminating the local area. These regulations are not restricted to new installations; however, must be applied to all facilities.

To reduce the impact on the environment, use a biodegradable insulating fluid such as natural ester fluid or synthetic ester fluid. As shown in Appendix B – Toxicity Testing, these insulating fluids do not show toxic characteristics to marine life. These fluids still require secondary containment but will reduce the impact on the environment if a spill occurred.

To eliminate the possibility of contaminating the waterways with an insulating fluid, use SF_6 as the insulating medium. In addition to eliminating the risk of contaminating the waterways, SF_6 does not require a secondary containment system.

Table 10 - Location and Containment Summary

Insulating Fluid	Secondary Containment	Hazard to Waterways
Mineral Oil	Required	High
Natural Ester Fluid	Required	Low
Synthetic Ester Fluid	Required	Low
SF_6	Not Required	None

Fire Protection

GSU power transformers are extremely reliable devices. If a failure does occur, only one in every ten result in an explosion or fire [8]. With proper monitoring, maintenance, and protection devices, transformer failures are reduced. In the rare occasion that a tank rupture does occur, there is a potential for a mist fire to start with the insulating fluid being the fuel for the fire. To limit the damage caused by such an event, use a high temperature insulating fluid or a fluid without the potential to ignite.

As previously discussed in Fire Safety, the insulating fluids in this paper have different fire potentials. For installations with major concerns for adjacent property damage due to a transformer fire, consider natural ester, synthetic ester, or SF_6 insulating fluids.

Table 11 - Fire Protection Summary

Insulating Fluid	Fire Risk
Mineral Oil	High
Natural Ester Fluid	Low
Synthetic Ester Fluid	Low
SF_6	No fire potential

Control Systems

No matter the insulating fluid, the control system of the transformer will operate the same with subtle differences in protection and monitoring devices. Outside of these minor differences, one major topic must be discussed; cooling operation. If considering a gas-insulated transformer, note that during a trip signal, the transformer will still produce heat after deenergization. Due to this, emergency power must be provided to maintain operation of the cooling fans for a minimum of 20-minutes. This would require an emergency generator with the ability to pick up emergency loads within a short period of time to prevent damage to the internal systems of the transformer. If the facility preparing for the transformer replacement does not have an emergency system sized for the transformer cooling fans and with a short-time startup ability, a gas-insulated transformer should not be considered, or an emergency power system would need to be installed.

Conclusion and Future Research

As the industry's power transformers are replaced, power generating companies will continue to look for ways to reduce environmental impact while increasing fire safety, reliability, and energy production. A growing awareness of the insulating fluid options for power transformers has caused a shift in transformer research, development, and use. More transformers are being designed and installed using an insulating fluid other than mineral oil. This migration will provide more data to further analyze the advantages and disadvantages of alternate insulating fluids.

The research that the Bureau of Reclamation has performed thus far provides sufficient information to justify the use of alternate insulating fluids. Natural ester fluid, synthetic ester fluid, and SF_6 gas insulating fluid are viable options when considering a power transformer replacement or attempting to mitigate the risks of the effects of transformer failures. Each project must be analyzed for the best insulating fluid type to use based on existing conditions.

Ester fluids, natural and synthetic, are a viable choice for insulating fluid in power transformers. Both fluids are biodegradable, non-toxic, thermally uprate the cellulose system within the transformer, and greatly improve the fire safety of the transformer. These fluids outperform mineral oil in many ways. Oxidation stability is an issue for natural ester fluid and can be overcome with attention to detail when opening the transformer for inspections/processing and ensuring the conservator on the transformer is always maintained. Pour point is only a concern for cold climates when a transformer is de-energized for several weeks. In most cases Reclamation generator step-up (GSU) transformers stay energized even when the generator is not online, so cold start issues are not as big of a concern. In the case that an ester fluid transformer is installed in a cold climate facility the standard operating procedures may need to be adjusted.

SF_6 insulated transformers almost eliminate fire safety and water/soil contamination concerns. This type of insulating fluid is obviously only available during a complete replacement of a transformer. SF_6 outperforms mineral oil in many ways but does introduce the concern of future regulations due to its high global warming potential. Research and development is ongoing for an alternate insulating gas for power transformers but currently SF_6 is the only available gas for this application at high voltages.

Reclamation will continue researching these alternate insulating fluids. Next goals are to develop life cycle cost values for installing transformers using each of the insulating fluids. These values will be developed for existing conditions that do not currently have fire protection and containment, have minimal fire protection and containment, and already have fire protection and containment installed. Currently, Reclamation is installing ten of the world's first 345-kV class, short-circuit tested, power transformers as well as four 230-kV class transformers at Glen Canyon Dam in Page, Arizona. Over the coming years, Reclamation will gather data on the operation and maintenance for these transformers. Measures are also being taken to install synthetic ester fluid and SF_6 gas-insulated transformers at other facilities. The Bureau of Reclamation's power transformer design specifications and Facility Instructions, Standards, and Techniques (FIST) manuals used for maintenance will be updated with findings as we progress through this shift in the industry.

References

[1] IEEE Std C57.154, IEEE Standard for the Design, Testing, and Application of Liquid-Immersed Distribution, Power, and Regulating Transformers Using High-Temperature Insulation Systems and Operating at Elevated Temperatures, IEEE Power & Energy Society, 2012.

[2] U.S. Department of Energy, Large Power Transformers and the U.S. Electric Grid, 2014.

[3] IEEE Std C57.91, IEEE Guide for Loading Mineral Oil-Immersed Transformers and Step-Voltage Regulators, IEEE Power & Energy Society, 2011.

[4] U.S. Bureau of Reclamation, "About," 25 April 2017. [Online]. Available: https://www.usbr.gov/projects/about.php. [Accessed 29 09 2019].

[5] S. V. a. P. Vishal, "Transformer's History and its Insulating Oil," in *Proceedings of the 5th National Conference on Computing for Nation Development*, New Delhi, 2011.

[6] D. Hart, "Dielectric Fluids for Transformer Cooling, History and Types," 2008.

[7] Toshiba, "SF6 Gas Transformers," 2019. [Online]. Available: https://www.toshiba.com/tic/transmission-distribution-systems/sf6-gas-transformers. [Accessed 29 09 2019].

[8] Factory Mutual Insurance Company FM 5-4 Transformers, "FM Global Property Loss Prevention Data Sheets," 2019.

[9] M&I Materials, "The Use of Ester Transformer Fluids for Increased Fire Safety and Reduced Costs," in *CIGRE 2012 Session Papers & Proceedings*, 2012.

[10] G. V. Research, "Sulfur Hexafluoride Market Size & Forecast Report, 2014-2025," Grand View Research, 2018.

[11] OECD, Test No. 301: Ready Biodegradabilitiy, OECD Guidelines for the Testing of Chemicals, Paris: OECD Publishing, 1992.

[12] IEEE Std C37.122.3, IEEE Guide for Sulfur Hexafluoride (SF6) Gas Handling for High-Voltage (over 1000 Vac) Equipment, IEEE Power & Energy Society, 2011.

[13] M. Lashbrook, "Use of Alternate Insulation Liquids," in *Doble Engineering Company - Life of a Transformer*, 2016.

[14] G. F. E. Agency, "Substances Hazardous to Waters," 03 12 2018. [Online]. Available: https://www.umweltbundesamt.de/en/topics/chemicals/substances-hazardous-to-waters. [Accessed 29 09 2019].

[15] M. L. R. Martin, "Fluid Maintenance and Dissolved Gas Analysis for Ester-based Transformer Liquids," M&I Materials Ltd, United Kingdom, 2015.

[16] M. L. Russell Martin, "Retrofilling with Ester Based Transformer Dielectric Fluid to Improve Fire Safety, Moisture Tolerance and Environmental Behaviour," M&I Materials Ltd, United Kingdom, 2011.

[17] O. Lesaint, "Prebreakdown Phenomena in Liquids and Their Relation with Breakdown Properties in High Voltage Applications," in *CIGRE*, 2007.

[18] A. Q. N.H. Malik, "Breakdown Mechanisms in Sulphur-Hexafluoride," *IEEE Transactions on Electrical Insulation,* Vols. EI-13, no. 3, pp. 135-145, 1978.

[19] IEEE Std C57.147, IEEE Guide for Acceptance and Maintenance of Natural Ester Fluids in Transformers, IEEE Power & Energy Society, 2008.

[20] IEEE Std C57.106, IEEE Guide for Acceptance and Maintenance of Insulating Mineral Oil in Electrical Equipment, IEEE Power & Energy Society, 2015.

[21] IEC 61099, Insulating Liquids - Specifications for Unused Synthetic Organic Esters for Electrical Purposes, International Electrotechnical Commission (IEC), 2010.

[22] Toshiba Transmission Distribution & Industrial Systems Company, "Toshiba Gas Insulated Transformer," Toshiba Corporation, Tokyo, Japan, 2012.

[23] CIGRE Working Group A2-35, "Experiences in Service with New Insulating Liquids," CIGRE, United Kingdom, 2010.

[24] Cargill, "Envirotemp FR3 Fluid Behavior in Cold Temperature Environments," Cargill, Hopkins, Minnesota, 2012.

[25] O. S. University, "PRISM Climate Group," [Online]. Available: http://prism.oregonstate.edu. [Accessed 14 08 2019].

[26] Metatech Corporation, "Cold Weather Operating Problems," 20 01 2000. [Online]. Available: http://www.metatechcorp.com/aps/cold_weather_operating_problems_.htm. [Accessed 19 08 2019].

[27] IEC 60076-14, Power Transformers - Part 14: Liquid-Immersed Power Transformers Using High-Temperature Insulation Materials, International Electrotechnical Commission (IEC), 2013.

[28] IEEE Std C57.93, IEEE Guide for Installation and Maintenance of Liquid-Immersed Power Transformers, IEEE Power & Energy Society, 2007.

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

[30] Bureau of Reclamation, US Army Corps of Engineers, Bonneville Power Administration, Western Area Power Administration, Federal Replacements - Units, Service Lives, Factors, Bureau of Reclamation, 2017.

[31] IEEE Std C57.155, IEEE Guide for Interpretation of Gases Generated in Natural Ester and Synthetic Ester-Immersed Transformers, IEEE Power & Energy Society, 2014.

[32] N.G.B. III et al, "2017 NESC(R) Handbook, Eighth Edition," *National Electrical Safety Code (NESC) Handbook, Eighth Edition*, 2016.

[33] IEEE Std C57.152, IEEE Guide for Diagnostic Field Testing of Fluid-Filled Power Transformers, Regulators, and Reactors, IEEE Power & Energy Society, 2013.

Appendix A – Fire Testing

The research was to understand the operating characteristics of ester fluids installed in power transformers. Originally the plan was to gather operating data from Glen Canyon Dam on their new power transformer, but due to manufacturing delays the first install of those transformers is happening now. Factory visits to witness inspections and testing of the transformers was a substitute task instead of gathering field data. Extensive literature searches of standards and papers were performed throughout the research to evaluate any new information as it emerged in industry. Aquatic toxicity testing of three ester fluids was performed by Hydraulic Investigations and Lab Services Group of the USBR Technical Service Center to verify the non-toxic classification of these fluids.

Ester fluids have a “Less-Flammable” fluid rating [32] and some scale fire testing was performed to gain more confidence in ester fluid fire protection ratings. The test method was put together from what was commercially available and cost effective. Fortunately, there is West Metro Fire Training Center near our office and leased us a space to conduct the testing safely. The test goal was to see what happens when the Envirotemp® FR3™ (hereafter referred to as FR3) is preheated to 150 ℃, which is the fire point of mineral oil, and set off a thermite pod inside the fluid. We wanted to see if the fluid would continue to burn or put itself out. The thermite pod was used as it was a readily available/portable energy source that would simulate an internal electrical fault. Thermite pods are used for exothermic welding of ground wires amongst other things.

The calculations for temperature rise of 2 gallons of FR3 are:

Specific Gravity = 0.92 @ 25 ℃ Specific Heat = 0.45 cal/g/m^3

Density of Water is 1000 kg/m^3 Density of FR3 0.92 * 1000 kg/m^3 = 920 kg/m^3

Volume of 2 Gallons = 0.00757082 m^3 Mass equals Volume * Density thus:

0.00757082 m^3 * 920 kg/m^3 = 6.965 kg or 6965 g

To convert calories to Joules: 1 cal = 4.184 J, 0.45 cal/gm/m^3 * 4.184 = 1.8828 J/g ℃

1.8828 J/g ℃ * 6965 g = 13113.7 J/℃

Theoretical energy content of the thermite pods = 5600 kJ

$$5{,}600{,}000J \div 13113.7\frac{\text{J}}{℃} = 427\ ℃$$

The theoretical temperature rise if we set off one of the thermite pods in 2 gallons of FR3 fluid is 427 ℃. FR3 has a fire point of 360 ℃ and the fluid was preheated to 150 ℃, so the fluid should burn if we can raise the temperature an additional 210 ℃ and provide significant oxygen/ignition. Approximately 50 % of the energy in the thermite pod would be able to raise the fluid 210 ℃. The time for the pod to release its energy is orders of magnitude slower than an electrical arc, but small portable sources of energy are hard to come by.

Two tests were performed:

- **Test 1.)** Thermite pod lowered to 2" below the surface of the fluid
- **Test 2.)** Thermite pod lowered to 4" below the surface of the fluid

Significant fires were produced with both tests as seen in Figure 14 and Figure 15. The fluid extinguished itself in both tests: **Test 1.) 30 s Test 2.) 28 s.**

Fire testing verified that once the ignition source is removed the fluid is self-extinguishing. Several Ester fluids are K class fluids which means they have a fire point greater than 300 ℃. Even though natural ester has a higher fire point than synthetic ester it has a lower overall fire safety class than synthetic. It is due to synthetic ester having a significantly lower calorific value. Lower calorific value is what aids in the self-extinguishing behavior when the energy source has been removed. In combination with a high fire point, low calorific value makes synthetic ester the top choice when choosing a "less flammable" fluid with a fire safety class rating of K3 as seen in Table 13.

Table 12 – Fire classification of liquids from IEEE C57.147-2018

Class	Fire Point	Class	Net calorific value
O	≤ 300°C	1	≥ 42 MJ/kg
K	> 300°C	2	< 42 MJ/kg & ≥ 32 MJ/kg
L	Not measurable	3	< 32 MJ/kg

Table 13 – Summary of Insulating Fluid Types and Fire Characteristics

Property	Mineral Oil	Natural Ester	Synthetic Ester
Flash Point	145 ˚ C	330 ˚ C	275 ˚ C
Fire Point	160 ˚ C	360 ˚ C	316 ˚ C
Auto Ignition	280 ˚ C	400 ˚ C	435 ˚ C
Calorific Value	46.0 MJ/kg	37.5 MJ/kg	31.6 MJ/kg
Fire Safety Class	O1	K2	K3

Figure 14 - Fire Test 1

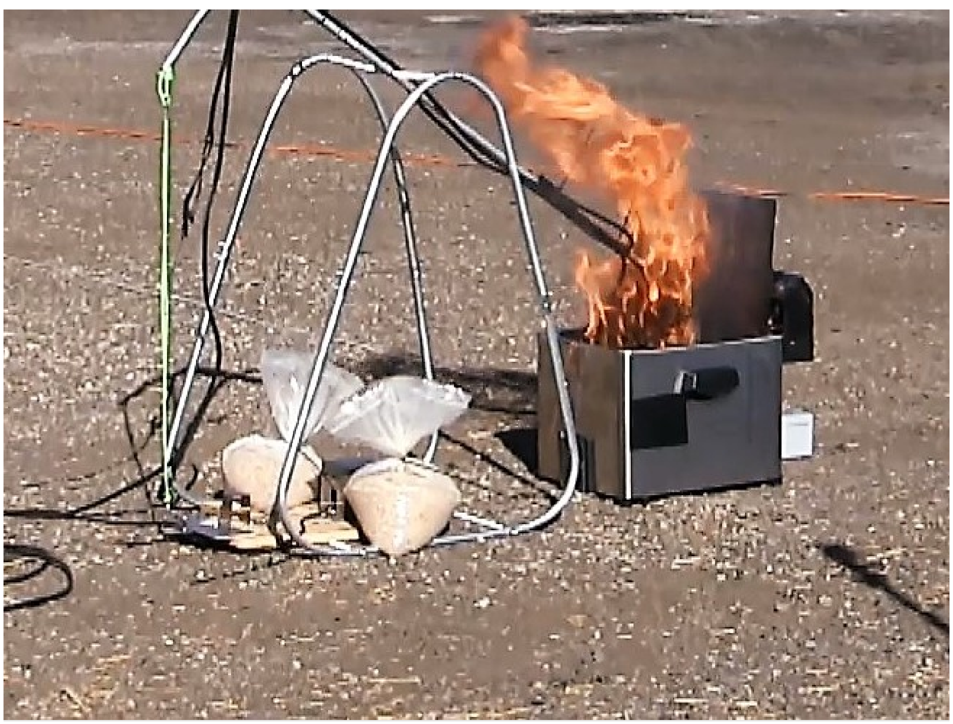

Figure 15 - Second Fire Test

Appendix B – Toxicity Testing

Envirotemp® FR3™, MIDEL 7131, and MIDEL eN 1204 Toxicity Tests

Prepared by: Sherri Pucherelli, Hydraulic Investigations and Lab Services

Acknowledgements

Assistance with study design, toxicity testing, and colony maintenance was provided by Denise Hosler, Yale Passamaneck, Jacque Keele, Diane Mench, Annie Quattlebaum, and Aaron Murphy of the Hydraulic Investigations and Lab Services Group. Additional support was provided by student interns, including Ben Hoffman and Rachel Banuelos. Chuck Hueth and Shaun Root of the Fisheries and Wildlife Resources Group provided space in the Reclamation, Technical Service Center Fish Lab, built the water bath, and secured and maintained the fish used in this test.

Introduction

Envirotemp FR3 (hereafter referred to as FR3) is a vegetable oil-based dielectric fluid, also referred to as a natural ester fluid, developed as an electrical insulating medium in liquid-filled electrical apparatus such as transformers. Although FR3 is comprised of >98.5% vegetable oil and <1.5% additives, end-users are subject to the United States Environmental Protection Agency (EPA) federal oil pollution prevention regulations under 40CFR112. The state of California (Cal/EPA) has developed acceptable toxicity characteristics for wastes, which includes such dielectric oils. According to the Code of California Regulations, Title 22, Section 66261.24(a)(6), a waste is considered to exhibit a toxic characteristic if the median lethal concentration (LC_{50}) is less than 500 mg/L when measured in soft water (total hardness 40 to 48 milligrams per liter of calcium carbonate).

Two laboratories have analyzed the toxicity of FR3 and the results are conflicting (Cal/EPA, 2002). The first tests were performed by Global Tox, an independent laboratory contracted by the original manufacturer (Cooper), and the second tests were performed by Associated Laboratories, an independent laboratory, which performed the work under contract with the Cal/EPA Department of Toxic Substances Control (DTSC). Global Tox reported an LC_{50} >1,000 mg/L for juvenile fish, while Associated Laboratories reported LC_{50} values <250 mg/L for juvenile fish and LC_{50} values for adult fish, ranging between 250 and 386 mg/L. The LC_{50} values reported by the Cal/ EPA contractor were well below the 500 mg/L California Toxicity Criteria. A description of the conflicting results is described in the Environmental Technology Verification Report prepared by the Cal/EPA DTSC (Cal/EPA, 2002). A DTSC aquatic toxicologist reviewed the reports prepared by both laboratories and found the main difference between the studies was the sample preparation method.

Global Tox analyzed samples per the Organization of Economic Cooperation and Development (OECD) procedure 203, *Fish Acute Toxicity Test*, using juvenile *Oncorhynchus mykiss* (rainbow trout) and oil samples prepared using an acetone carrier solvent to make the oil miscible in water. Associated Laboratories analyzed samples per the U.S. EPA method, Methods for measuring the Acute Toxicity of Effluents and Receiving Waters to Freshwater and Marine Organisms, EPA/600/4-90/027F, August 1993, testing juvenile and adult *Pimephales promelas* (fathead minnow). Samples were prepared by the "Static Acute Bioassay Procedures for Hazardous Waste Samples" developed by the California Department of Fish and Game, Water Pollution Control Laboratory in the Code of California Regulations, Title 22, Section 66261.24(a) (6), which requires shaking the sample for six hours using a wrist-action or similar type of shaker to dissolve the oil in 200 mL of water before the sample is added to the bioassay fish tank.

The oil in samples prepared by the wrist-action shaker method does not completely dissolve and stratifies at the top of the tank. Fish can become coated with the oil, which may impair gill function. Samples prepared with acetone carrier solvent method are thought to provide results that reflect systemic or chemical impacts on fish. California DTSC typically requires that both sample preparation methods are used to prepare insoluble, viscous waste samples, and the method yielding the most conservative LC_{50} is used for the definitive tests. Oil samples prepared with the wrist-action shaker method are thought to provide a more realistic result for an environmental release. The LC_{50} results and physical effects observed by Associated Laboratories have been observed in other tests on vegetable based oils and oils in general.

Reclamation is considering using ester fluids in transformers at hydropower facilities. The primary goal of this research was to independently conduct toxicity tests using the freshwater crustacean *Daphnia pulex* and fathead minnow (*Pimephales promelas)* to more clearly understand the potential toxic effects of FR3 in the case of an environmental spill. Toxicity testing was also completed using MIDEL eN 1204 for natural ester fluids and MIDEL 7131 for synthetic ester fluid using the fathead minnow (*Pimephales promelas)*.

Methods

Daphnia pulex

Test animals and culture

Daphnia pulex colonies were cultured and tested following the methods described in Standard Methods for the Examination of Water and Wastewater. Colonies were maintained in three, 3-L glass tanks containing synthetic (reconstituted) moderately hard water. Culture water was prepared by dissolving 96 mg/L $NaHCO_3$, 60 mg/L $CaSO_4 \cdot 2H_2O$, 60 mg/L $MgSO_4$, and 4 mg/L KCL in deionized water and was aerated for several hours prior to use. Culture water was replaced, and tanks were cleaned weekly.

Culture vessels were placed in a water bath where water temperature was maintained at 22 ± 2°C with a water chiller and heater (Figure 16). Colonies were continuously aerated. *D. pulex* were fed a suspension of trout chow, alfalfa, and yeast. Each culture vessel received 1.5 mL of prepared food per 1,000 mL of water, three times per week.

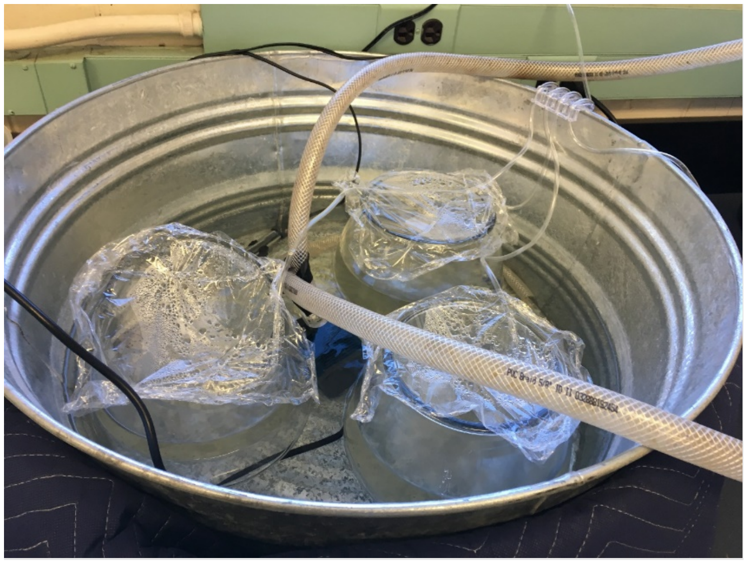

Figure 16 - Daphnia Culture Vessels in Water Bath

Test system, exposures and assessments

Short-term, static, non-renewal tests were run for 72 hours. Two, 72-hour range-finding tests were conducted in order to determine the approximate concentration range to be included in the definitive test. The range-finding tests were designed to include concentrations that would kill all organisms and others that would kill very few organisms. Six concentrations of FR3 were examined in the first range-finding test, and five, lower concentrations were examined in the second range-finding test (Table 14). The five concentrations used in the definitive test were based on the findings of the initial tests, and represent concentrations that produced *D. pulex* mortality near and around 50% after 72 hours (Table 14).

Table 14 - FR3 Concentrations Examined in each D. pulex toxicity test

Range-finding test 1	Range-finding test 2	Definitive test
500,000 mg/L	7,812 mg/L	125,000 mg/L
250,000 mg/L	3,906 mg/L	62,500 mg/L
125,000 mg/L	1,953 mg/L	31,250 mg/L
62,500 mg/L	976 mg/L	15,625 mg/L
31,250 mg/L	488 mg/L	7,812 mg/L
15,625 mg/L		

Each concentration was tested in replicates of three with a control in 150-mL glass beakers, containing 100 mL of solution. Solutions were prepared by combining the appropriate concentration of FR3 and fresh culture water in a Nalgene bottle. Controls were comprised of culture water only. Each bottle was placed on a shaker-table for 6-hours. Solutions were transferred into 150-mL glass beakers and placed in a water bath maintained at 22 ± 2°C (Figure 17). Ten, daphnid neonates (first instar ≤ 24 h old) were introduced into each beaker, below the surface of the solution, with a large-bore plastic pipet. *D. pulex* were not fed or aerated for the duration of the test. Each daphnid was examined for mortality at 24 hour intervals for a total of 72 hours. Only nonmotile *D. pulex* were considered dead. Survival rates of at least 90% in control tests were required for test validation.

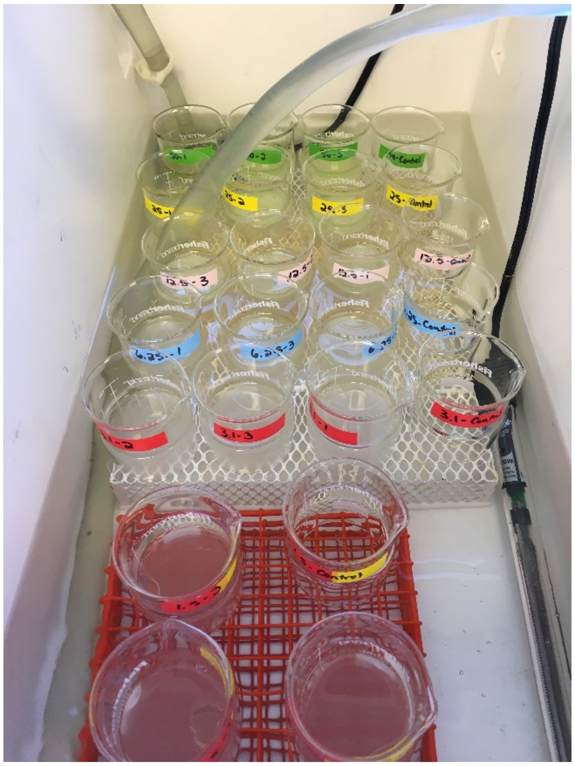

Figure 17 - Water Bath Containing D. pulex Toxicity Test Breaker Replicates Containing FR3 Solutions

Data analysis

The median lethal concentration (LC_{50}) and 95% confidence limits were calculated using probit analysis (Finney, 1971), which is a specialized regression model of binomial response variables. The LC_{50} value tells you the concentration at which 50% of the test organisms would be killed within a specified time frame, 48 and 72 hours in this case. Higher LC_{50} values are less toxic than lower LC_{50} values because a greater concentration is required to produce 50% mortality.

Pimephales promelas

Test animals and culture

Juvenile *Pimephales promelas* (fathead minnow) were maintained and tested in the Reclamation, Technical Service Center Fish Laboratory, following the methods described in Standard Methods for the Examination of Water and Wastewater. Fish were treated with Paracide Green and 5 ppt salt bath for 3 days prior to initiating testing to insure they did not carry disease. Fish were held in 600 gallon tanks that were regularly cleaned and maintained at 17.2°C with proper aeration and a 16h light/ 8h dark photoperiod. Water quality was closely monitored as per the Reclamation Fish Lab Standard Operating Procedure. The alkalinity and hardness of culture water was determined via titration method and was found to be 39 mg/L and 74 mg/L, respectively, which is considered soft to moderately hard.

Test system, exposures, and assessments

Short-term, static, non-renewal tests were run for 96 hours. Two, 96-hour range-finding tests were conducted in order to determine the approximate concentration range to be included in the definitive test. Five concentrations of FR3 were examined in the first range-finding test, and four higher concentrations were examined in the second range-finding test (Table 15). Controls were included in each test. Definitive tests were not conducted because none of the concentrations tested caused mortality anywhere near 50%. Similar concentrations of MIDEL 7131 and MIDEL eN 1204 were examined in three range-finding tests (
Table 16). Space availability on the shaker-table required three range-finding tests for the MIDEL tests.

Table 15 - FR3 Concentrations Examined in each Fathead Minnow Toxicity Test

Range-finding test 1	Range-finding test 2
3,906 mg/L	125,000 mg/L
1,953 mg/L	62,500 mg/L
976 mg/L	31,250 mg/L
488 mg/L	7,812 mg/L
244 mg/L	

Table 16 - MIDEL 7131 and eN 1204 Concentrations Examined in each Fathead Minnow Toxicity Test

Range-finding test 1	Range-finding test 2	Range-finding test 3
3,906 mg/L	62,500 mg/L	125,000 mg/L
1,953 mg/L	31,250 mg/L	
976 mg/L	15,625 mg/L	
488 mg/L	7,812 mg/L	
244 mg/L		

Each concentration was tested in replicates of two, in 10-gallon glass fish tanks, containing 30 L of solution. Solutions were prepared by combining the appropriate concentration of FR3 or MIDEL oil with at least 200 mL fresh culture water. Each solution was prepared in a Nalgene bottle and placed on a shaker-table for 6-hours. The solutions were then added to the fish tanks containing the rest of the water and test fish, controls received culture water only. Ten fish were included in each replicate. Prior to loading fish, a group weight was recorded to confirm the load densities did not exceed 0.8 g/L. Fish weights were limited to minimize oxygen depletion, metabolic weight accumulation, and crowding induced stress.

The tanks were placed in a water bath, maintained at 17.2 ± 2°C, and each tank received aeration for the duration of the tests (Figure 18). The temperature, dissolved oxygen (DO), pH, and ammonia were monitored during the 96-hour tests. Temperature and DO were measured with a Hydro-lab multi-probe, and pH and ammonia were measured with Hach test strips. Fish feeding was terminated 48 hours prior to the start of the tests, and fish were not fed during the study to reduce the amount of ammonia produced. Each fish was examined for mortality at 24-hour intervals for a total of 96 hours. Dead fish were weighed and measured (total length and fork length) (Figure 19). All surviving fish were euthanized at the end of the tests by tricaine methanesulfonate (MS-222) overdose and each fish was individually weighed and measured to compare sizes between each treatment and control replicate.

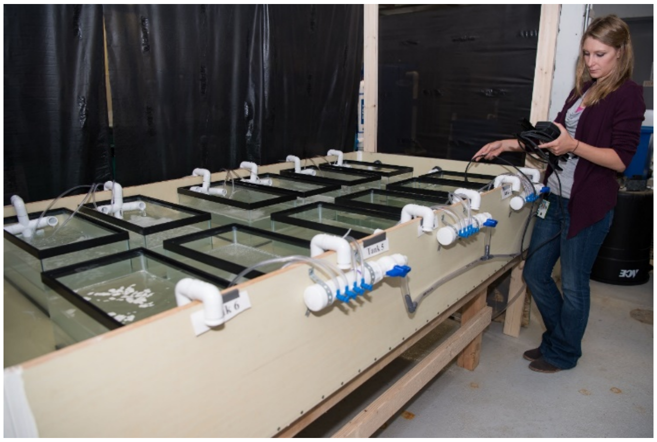

Figure 18 - Test Tank Replicates Containing FR3 Solution in Water Bath for Fathead Minnow Toxicity Testing

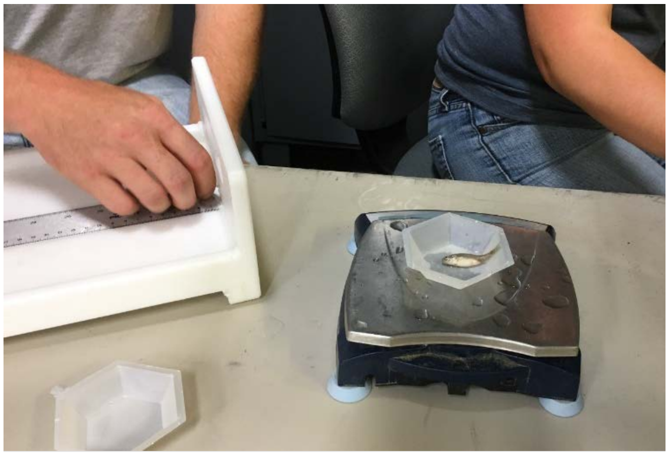

Figure 19 - Fish Weight and Length Measurements

Data analysis

Statistix analytical software was used to determine mean and standard deviation of water quality parameters, fish weight, total length, and fork length between concentration groups. Factorial analysis of variance (ANOVA) was used to test for differences in fish weight, total length, and fork length between FR3 concentration groups. If the overall F test was significant, values were compared with the Least Significant Difference (LSD) method.

Results

Daphnia pulex

Solutions were prepared via the wrist-action shaker method instead of the acetone carrier solvent method because it was not possible to completely dissolve most of the FR3 oil in 0.5 mg/L or less of acetone. Although most of the oil eventually stratified at the top of the beaker, we believe the shaking method provided an exposure that was more comparable to an environmental spill. In the first range-finding test, daphnia mortality was greatest at 48 and 72 hours in the 125,000 and 62,500 mg/L concentrations, despite not being the highest concentrations tested (Figure 20). After 48 hours, mortality was lowest at the highest concentrations.

These results may be in-part due to the limited mixing of the oil and water at the higher concentration. Visual comparisons of the higher and lower concentration solutions indicate that the oil was more thoroughly homogenized in lower concentration replicates. This difference is obvious between the 500,000 mg/L and 62,500 mg/L solutions shown in Figure 21. *D. pulex* may have been able to escape the oil in the higher concentration tests by staying below the stratified oil (Figure 21). *D. pulex* would frequently become caught on small oil droplets on the sides of the beaker or in larger oil clusters at the surface. Many *D. pulex* caught in the oil were able to survive for several days. Dead *D. pulex* were typically found with some amount of oil on their body. None of the lower concentrations tested in the second range-finding test produced 50% mortality after 72 hours (Figure 22).

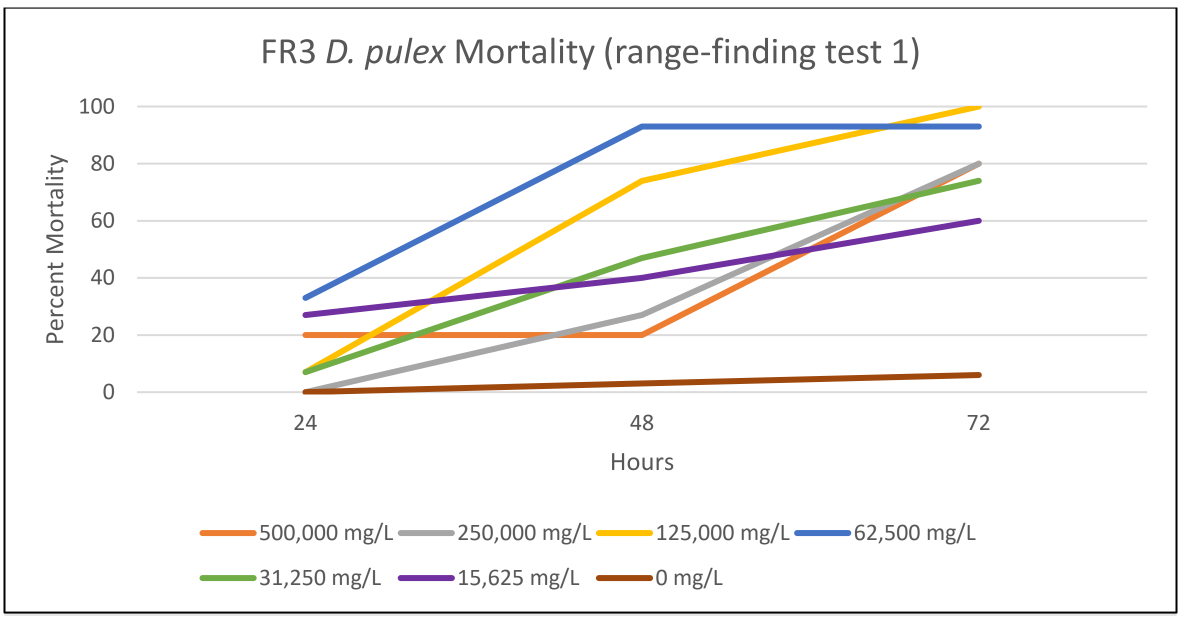

Figure 20 - D. pulex Mortality Observed at Six FR3 Concentrations in the First Range Finding Test

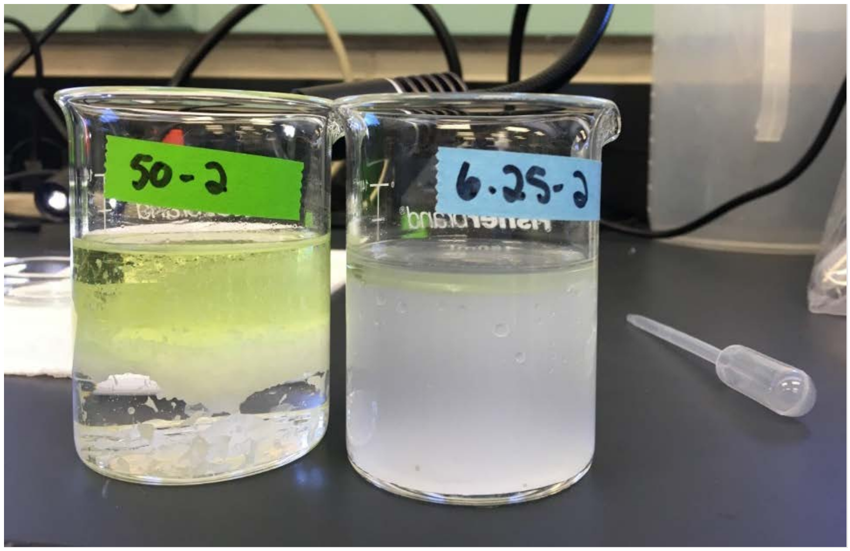

Figure 21 - Comparison of FR3 Mixing in the 500,000 mg/L (left) and 62,500 mg/L (right) Solutions

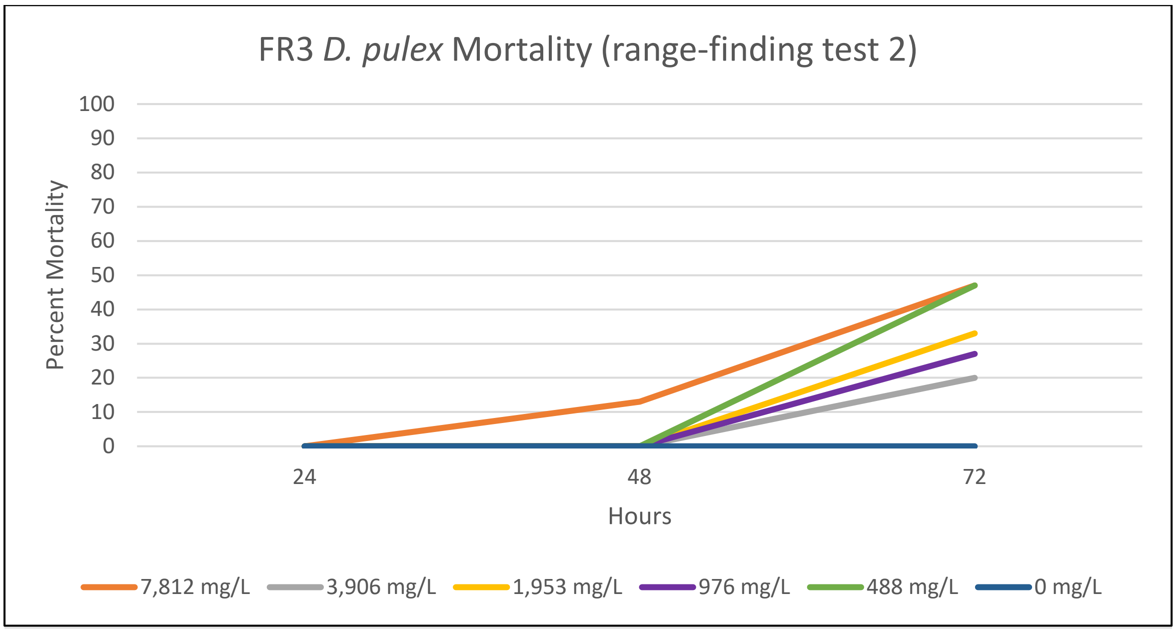

Figure 22 - D. pulex Mortality Observed at Five FR3 Concentrations in the Second Range Finding Test

Similar mortality results were observed in the definitive test (Figure 23). Probit analysis of data collected during the definitive test found the 48 hour LC_{50} to be 36,738 mg/L with a 21,104 mg/L lower confidence limit (95% fiducial CI) and 63,953 mg/L upper confidence limit (Figure 24). The 72 hour LC_{50} was 15,784 mg/L with a 10,172 mg/L lower confidence limit and 24,490 mg/L upper confidence limit (Figure 25). Higher LC_{50} values indicate lower toxicity and the LC_{50} values obtained in the study are significantly higher than the 500 mg/L California toxicity standard.

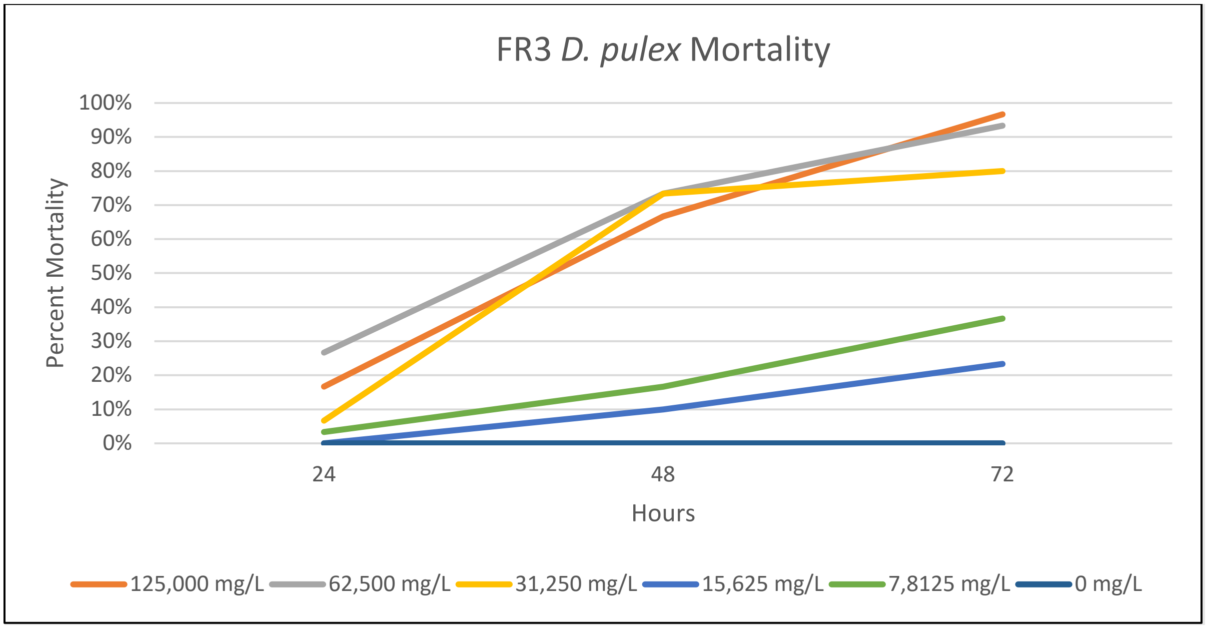

Figure 23 - D. pulex Mortality Observed at Five FR3 Concentrations During the Definitive Test

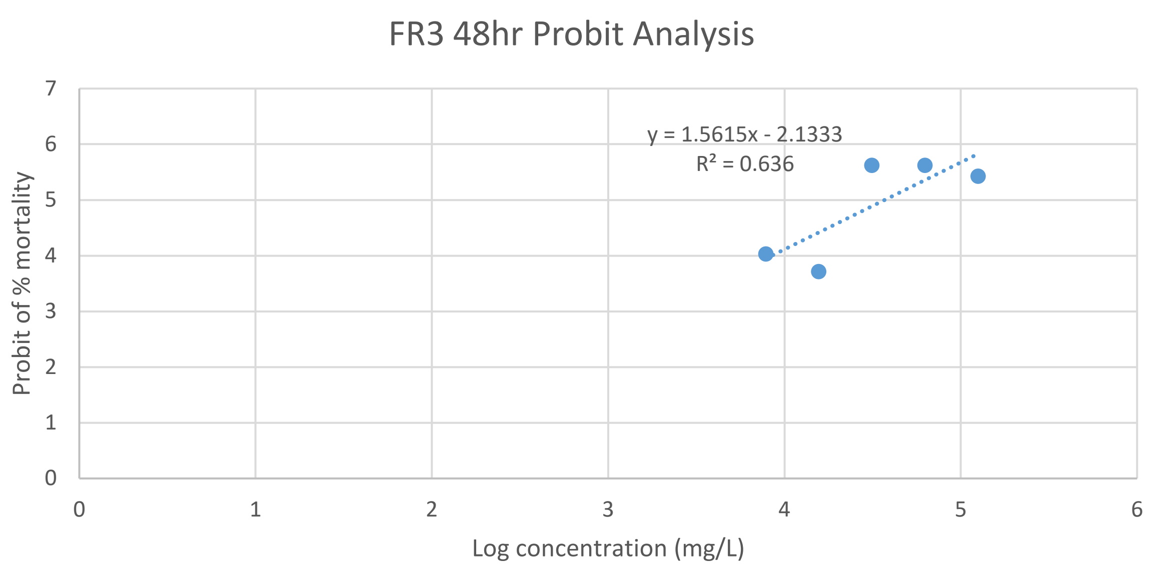

Figure 24 - Probit Analysis of D. pulex Mortality at Five FR3 Concentrations after 48-hours

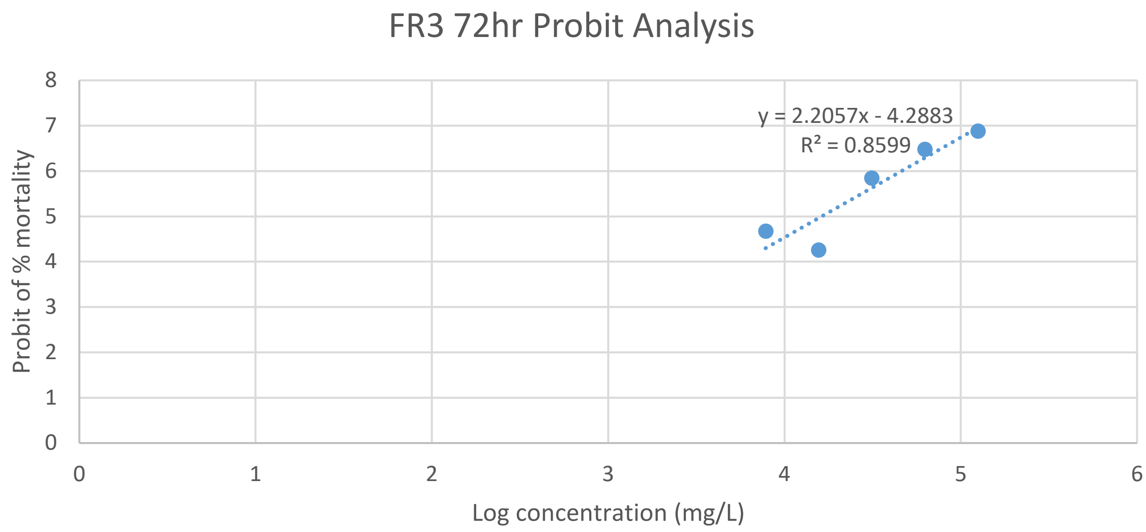

Figure 25 - Probit Analysis of D. pulex Mortality at Five FR3 Concentrations after 72-hours

Pimephales promelas

A total of three fish died during the FR3 range-finding tests and appeared to be random, natural mortality. One fish in the 488 mg/L test died at 48 hours, one fish in the 1,953 mg/L test died at 96 hours, and one fish in the 0 mg/L control (test 2) died at 24 hours. A definitive test was not conducted due to the random and low mortality observed in the range-finding tests. No mortality was observed in the highest concentration tested (125,000 mg/L) and testing higher concentrations was not practical or realistic (Figure 26). The oil added to the fish tanks did tend to stratify to the top of the tank, even with constant agitation provided by the aeration. Fish were observed coming into contact with the oil at the surface of the tank.

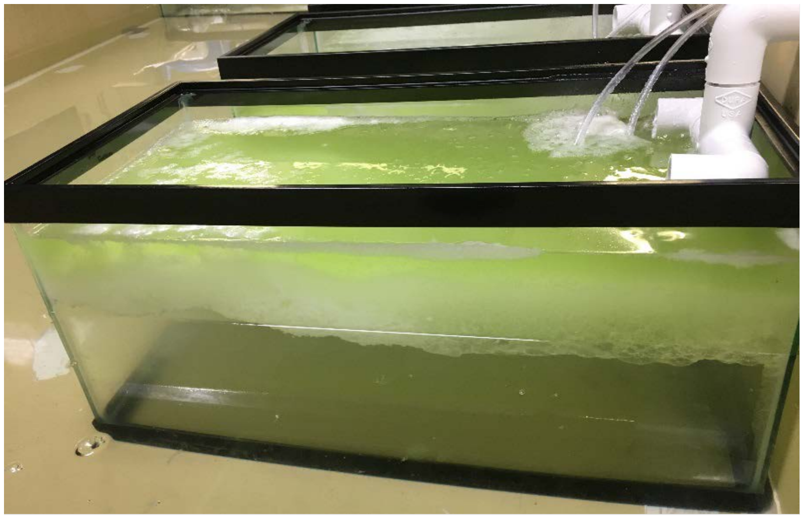

Figure 26 - Test Tank Containing 125,000 mg/L of FR3, the Highest Concentration of Fluid Tested

Water quality did not dramatically fluctuate in any of the test tanks during the study (Table 17, Table 18, and Table 19). Temperature and dissolved oxygen could only be monitored in the control tanks because these variables were measured using a multi-probe and exposing the multi-probe to the oil would have damaged the equipment. Therefore comparisons could not be made for these variables. The mean temperature and DO observed in control tanks did not differ dramatically during the tests and it can be assumed that these variables did not impact the fish in other tanks due to the overall low mortality. pH and ammonia levels were collected daily in each tank and never reached levels of concern (critical ammonia level is ≥ 0.5 mg/L).

In the FR3 tests, fish size was not significantly different between concentrations tested, based on weight (p=0.0618), total length (p=0.7647), and fork length (p=0.9347) (Table 20). The average weight, total length and fork length of fish used in the first test was 1.26 g, 50.44 mm, and 46.57 mm respectively. The two fish that died in the first test were similar to the average, weighing slightly more than average (1.4 g, 54 mm, 50 mm and 1.3 g, 47 mm, 45 mm). The average weight, total length and fork length of fish used in the second test was 1.19 g, 51.07 mm, and 47.42 mm respectively. The fish that died in the second test was slightly larger than average (1.4 g, 51 mm, 48 mm). The fish used in the MIDEL tests were similar in size to those used in the FR3 tests (Table 21 and Table 22).

Table 17 - Mean (SD) pH, Ammonia, Temperature, and Dissolved Oxygen by Treatment Group Throughout the FR3 Study

FR3 Concentration (mg/L)	pH	Ammonia (mg/L)	Temperature (°C)	Dissolved Oxygen (mg/L)
0 (Control)	6.68 (0.48)	0.43 (0.17)	17.88 (0.10)	9.48 (0.08)
244	6.00 (0.00)	0.32 (0.12)	17.80	9.44
488	6.00 (0.00)	0.25 (0.00)	17.85	9.41
977	6.00 (0.00)	0.28 (0.08)	17.85	9.45
1,953	6.00 (0.00)	0.30 (0.11)	17.80	9.45
3,906	6.00 (0.00)	0.28 (0.08)	17.80	9.45
7,812	6.60 (0.55)	0.25 (0.00)	18.10	9.36
31,250	7.00 (0.00)	0.25 (0.00)	18.10	9.35
62,500	7.00 (0.00)	0.25 (0.00)	18.20	9.36
125,000	7.00 (0.00)	0.30 (0.11)	18.00	9.40

Table 18 - Mean (SD) pH, Ammonia, Temperature, and Dissolved Oxygen by Treatment Group Throughout the MIDEL 7131 Study

MIDEL 7131 Concentration (mg/L)	pH	Ammonia (mg/L)	Temperature (°C)	Dissolved Oxygen (mg/L)
0 (Control)	7.79 (0.11)	0.00 (0.00)	16.68 (0.20)	7.61 (0.23)
244	7.55 (0.26)	0.00 (0.00)	16.90	7.69
488	7.54 (0.25)	0.00 (0.00)	16.95	7.64
977	7.40 (0.29)	0.00 (0.00)	17.00	7.63
1,953	7.70 (0.33)	0.00 (0.00)	16.95	7.63
3,906	7.76 (0.33)	0.00 (0.00)	17.00	7.66
7,812	7.81 (0.25)	0.00 (0.00)	16.90	7.25
15,625	7.26 (0.83)	0.00 (0.00)	16.90	7.26
31,250	7.28 (0.83)	0.00 (0.00)	16.80	7.47
62,500	7.58 (0.16)	0.00 (0.00)	16.80	7.62
125,000	7.25 (0.98)	0.00 (0.00)	17.20	7.55

Table 19 - Mean (SD) pH, Ammonia, Temperature, and Dissolved Oxygen by Treatment Group Throughout the MIDEL eN 1204 Study

MIDEL eN 1204 Concentration (mg/L)	pH	Ammonia (mg/L)	Temperature (°C)	Dissolved Oxygen (mg/L)
0 (Control)	7.61 (0.35)	0.10 (0.20)	16.60 (0.20)	7.69 (0.22)
244	7.25 (0.26)	0.00 (0.00)	16.90	7.42
488	7.40 (0.32)	0.00 (0.00)	16.85	7.36
977	7.55 (0.44)	0.00 (0.00)	16.85	7.36
1,953	7.35 (0.34)	0.00 (0.00)	16.90	7.06
3,906	7.10 (0.66)	0.00 (0.00)	16.95	7.45
7,812	7.30 (0.26)	0.00 (0.00)	16.75	7.56
15,625	7.30 (0.42)	0.03 (0.08)	16.75	7.57
31,250	7.30 (0.35)	0.03 (0.08)	16.55	7.64
62,500	7.40 (0.21)	0.00 (0.00)	16.60	7.63
125,000	7.59 (0.18)	0.35 (0.41)	16.60	7.60

Table 20 - Mean (SD) Fish Weight, Total Length, and Fork Length by Treatment Group Throughout the FR3 Study

FR3 Concentration (mg/L)	Fish Weight (g)	Total Length (mm)	Fork Length (mm)
0 (Control)	1.17 (0.27)	50.76 (3.87)	47.14 (3.57)
244	1.22 (0.77)	50.35 (3.31)	46.70 (3.20)
488	1.35 (0.31)	50.65 (2.70)	46.65 (2.72)
977	1.36 (0.33)	51.33 (3.02)	47.62 (3.04)
1,953	1.29 (0.20)	50.15 (3.08)	46.30 (2.79)
3,906	1.27 (0.27)	50.05 (2.46)	45.79 (2.07)
7,812	1.07 (0.41)	49.80 (5.58)	46.00 (5.35)
31,250	1.25 (0.24)	51.87 (2.56)	48.13 (2.23)
62,500	1.21 (0.26)	51.60 (3.68)	47.93 (3.47)
125,000	1.21 (0.27)	51.00 (3.40)	47.27 (3.31)

Table 21 - Mean (SD) Fish Weight, Total Length, and Fork Length by Treatment Group Throughout the MIDEL 7131 Study

MIDEL 7131 Concentration (mg/L)	Fish Weight (g)	Total Length (mm)	Fork Length (mm)
0 (Control)	1.21 (0.49)	47.65 (6.54)	44.52 (6.36)
244	1.26 (0.45)	49.15 (5.51)	46.10 (5.18)
488	1.25 (0.51)	49.70 (5.21)	45.95 (4.90)
977	1.01 (0.40)	46.19 (5.22)	43.48 (4.88)
1,953	1.21 (0.31)	49.15 (3.97)	46.00 (3.71)
3,906	1.16 (0.33)	48.20 (3.76)	45.15 (3.84)
7,812	1.14 (0.43)	47.24 (6.07)	44.71 (5.75)
15,625	1.14 (0.40)	47.75 (5.72)	45.05 (5.41)
31,250	1.35 (0.35)	50.20 (4.24)	47.20 (4.05)
62,500	1.18 (0.35)	49.10 (4.52)	45.95 (4.27)
125,000	1.23 (0.46)	49.65 (5.22)	46.90 (5.08)

Table 22 - Mean (SD) Fish Weight, Total Length, and Fork Length by Treatment Group Throughout the MIDEL eN 1204 Study

MIDEL eN 1204 Concentration (mg/L)	Fish Weight (g)	Total Length (mm)	Fork Length (mm)
0 (Control)	0.84 (0.66)	42.51 (9.28)	40.10 (8.89)
244	0.69 (0.58)	39.75 (9.66)	38.00 (9.86)
488	0.76 (0.73)	38.45 (11.72)	36.15 (10.89)
977	0.41 (0.25)	34.65 (5.71)	32.65 (5.65)
1,953	0.45 (0.37)	35.47 (6.46)	33.11 (6.05)
3,906	0.63 (0.69)	37.00 (9.35)	34.73 (9.04)
7,812	1.32 (0.93)	48.05 (10.40)	45.45 (10.27)
15,625	1.03 (0.71)	44.75 (10.44)	42.20 (9.90)
31,250	0.98 (0.80)	43.15 (11.21)	41.35 (11.30)
62,500	0.56 (0.33)	37.95 (6.26)	35.60 (5.79)
125,000	0.99 (0.78)	44.40 (10.51)	41.85 (9.93)

Conclusions

Reclamation is considering using ester dielectric fluids in transformers at hydropower facilities. The goal of this study was to independently examine the relative toxicity of FR3, MIDEL 7131, and MIDEL eN 1204 to determine how a spill would impact organisms downstream of the facility. The contradictory results of the toxicity tests conducted by two different labs using different methods prompted Reclamation to conduct an independent test. The previous FR3 toxicity studies were conducted with fish and the lab that found higher mortality observed fish gills were coated with oil, impairing gill function. Because the fish were physically affected by the oil, Reclamation decided to also test *D. pulex,* an animal that is morphologically distinct from fish.

There are several, relatively comparable, standard methods available for conducting toxicity tests. While the labs who did the original testing used different standard methods, the only significant differences between tests were the fish species used and the solution preparation method. Conducting toxicity tests with oils is difficult, because the oil does not easily or completely mix with the diluting liquid. The two common methods for preparing oil solutions include the shaker method, where the oil and diluting liquid are agitated for six hours, and the carrier solvent method where a minimal amount (no greater than 0.5 mg/L, Standard Methods for the Examination of Water and Wastewater) of solvent is added to the solution. We tested both methods to determine which provided better mixing. The acetone solvent (at 0.5 mg/L) and the shaking method resulted in similar amounts of surface oil stratification, even at low concentrations. The shaker method was selected because it seemed more comparable to an environmental release and it did not introduce another variable (chemical solvent) to the test.

The short term (72 hour) *D. pulex* LC_{50} was found to be 15,784 mg/L which is significantly higher than the current California standard. The state of California considers dielectric fluids with an LC_{50} less than 500 mg/L to exhibit toxic characteristics. This standard is based on soft water with hardness between 40-48 mg $CaCO_3$/L. The *D. pulex* test was conducted in moderately hard water (80-90 mg $CaCO_3$/L) because *Daphnia* are sensitive to media hardness and moderately hard water is suggested for rearing *D. pulex*. The short term LC_{50} for fathead minnow in soft water was found to be >125,000 mg/L. The exact LC_{50} was not determined because of the low mortality observed. Like the FR3 tests, the MIDEL 7131 and eN 1204 oils did not produce fathead minnow mortality at any of the doses tested.

The Cal/EPA DTSC contract lab found LC_{50} values below the California toxicity standard for fathead minnows exposed to FR3, while our LC_{50} values for *D. pulex* and fathead minnow were well above the standard. Although we did use a different standard operating procedure, our test methods were comparable to the Cal/EPA DTSC test. It is unclear why our results are so different from the previous study, as we did observe fish coming in contact with the oil at the top of the tanks without significant mortality.

We believe the results of these static tests are extremely conservative in comparison to an environmental release downstream of a facility. Water flow rates and turbulence are typically high downstream of dams, and if there was a large-scale spill of stored dielectric fluid it would be quickly diluted. But it is possible that the oil could pool in slower moving eddies further downstream leading to a more concentrated exposure. The results of this study indicate that Envirotemp FR3, MIDEL 7131, and MIDEL eN 1204 do not exhibit toxic characteristics.

References

Standard Methods for the Examination of Water and Wastewater. 23rd ed. 2017. Edited by Rodger B. Baird and Andrew D. Eaton, APHA, Washington, DC, 1998.

United States, Environmental Protection Agency, California Environmental Protection Agency, Department of Toxic Substances Control. Environmental Technology Verification Report: Cooper Power Systems Envirotemp® FR3™ Vegetable Oil-Based Insulating Dielectric Fluid. May 2002. DTSC R-02-02. EPA 600/R-02/042.