SPACING CONSIDERATIONS BETWEEN SUBSTATION BUILDINGS AND LIQUID TYPE TRANSFORMERS

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Abstract – Substation buildings exist at every petrochemical facility; located at the incoming power high-voltage substation or switchyard through all levels of distribution downstream. Typically, large, liquid type transformers are located near these substations to step voltages down to levels required by process units or other loads. This paper examines current industry standard requirements and recommendations, fire considerations, and best engineering practices used when installing new liquid type transformers, or retrofilling existing liquid type transformers with several types of dielectric liquids. The scope of this paper is limited to in-plant power distribution outdoor transformers that have secondary voltages ranging from 480 V to 35 kV and are also limited to installations subject to ANSI/NEMA codes and standards.

Index Terms – Substation, oil-filled, liquid-filled, equipment spacing, less-flammable, mineral insulating liquid, mineral oil, ester liquid, natural ester liquid, synthetic ester liquid

I. INTRODUCTION

The term *substation* within this paper means any stand-alone building, structure, or enclosed space that contains electrical distribution equipment. It includes prefabricated buildings or structures commonly referred to as *power distribution centers* (PDCs). The substations are assumed to have (a) liquid type transformer(s) located nearby. The term *transformer* indicates a liquid type power transformer with either mineral insulating liquid (mineral oil) or ester liquids, but not silicone.

Although not a common occurrence, transformers occasionally fail. Fortunately, transformers are typically robust, and failures usually have minimal consequences. Operating companies that implement frequent, thorough testing and maintenance programs have a history of thousands of transformers in service for decades with virtually no fires. While a transformer failure that results in downtime and loss of production is already negative, the situation is exponentially worsened by an accompanying fire. Certain fire risks are inherent to placing medium and high voltage transformers, especially mineral insulating liquid type transformers, near any building or structure. Surprisingly, there are no prescriptive mandatory national statutes requiring minimum distances between transformers and substations.

On the one hand, the authors share the opinion that compliance with mandatory codes and standards is a must. Accepted industry practices, guidelines, and recommended practices should always be considered while allowing leeway for qualified individuals to make educated engineering decisions.

On the other hand, design engineers often have nothing but their best judgment and sometimes vague industry-recommended practices and guidelines to determine exactly *how close is too close* when determining proper spatial separation, and if the initial costs of better transformer liquids and/or other mitigation techniques are justified.

II. CODES, STANDARDS, PRACTICES, & GUIDES

While there are currently no mandatory national codes with which one must comply for spatial separation between a structure and liquid type transformer, the go-to documents are typically the guides published by the Institute of Electrical and Electronics Engineers (IEEE), the National Fire Protection Association (NFPA), and testing agencies/insurers, such as FM Global.

This article specifically considers:

1) ANSI/IEEE Std. 979™, 2012 Edition, *IEEE Guide for Substation Fire Protection* [1].

2) NFPA 850®, 2020 Edition, Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations [2]; &

3) FM Global Property Loss Prevention Data Sheet 5-4 (FM 5-4) [3].

A. Institute of Electrical and Electronic Engineers

The current edition of IEEE Std. 979 [1] contains safety guidelines that are typically consulted to determine a minimum safe spacing distance between transformers and substations. Unfortunately, many times the current recommended separations cannot be achieved because of space constraints. The updated version, tentatively targeted for publication in 2022, will most likely include better guidance for installing liquid type transformers and related fire safety issues.

B. National Fire Protection Association

The most prominent code for most electrical engineers, at least in the U.S., is the National Electrical Code® (NEC®) [4]. However, Section 450.27 [4] only addresses general fire safeguards for medium voltage (MV) transformers where installed outdoors.

The NFPA has many other fire codes, however, and one that is commonly consulted for guidance is NFPA 850 [2]. While the title does not seem to be applicable to petrochemical plants, NFPA 850 [2] contains information that can be applied to a certain extent to transformer and substation installations in petrochemical facilities. Power generating plants have different hazards and risks; thus, NFPA 850 [2] in its entirety is not applicable to petrochemical facilities.

C. Factory Mutual Group

FM Global Property Loss Prevention Data Sheet 5-4 [3] contains perhaps the most-defined recommendations for separating mineral liquid type and ester liquid type transformers from substations, along with recommendations regarding the use of FM Approved transformers. While FM 5-4 [3] is not an "industry standard" per se, it contains recommended spacing tables for transformer-building separation, with corresponding figures.

FM Approval Standard for Less Flammable Transformer Fluids, Class Number 6933, Section II [5] contains the following criteria for classifying an FM Approved less-flammable liquid:

1) The liquid fire point[a] shall be at least 572°F (300°C);
2) The liquid manufacturer's surveillance program shall determine the dielectric breakdown voltage, the neutralization number, the color, the water content, and the viscosity; and
3) For identification purposes, infrared spectra may have to be performed based on the certification agency's requirement;
4) For identification purposes, gas chromatography mass spectrometry may have to be performed based on the certification agency's requirement [5].

[a] "*Fire point*" is the lowest temperature at which a specimen will keep burning for at least five seconds under specified test conditions [6].

III. TRANSFORMER LIQUIDS CONSIDERATIONS

Most industrial transformers, 500 kVA and larger, are liquid type. The benefits of liquid type transformers greatly exceed any associated risks. Liquids provide a medium to transfer internal heat to the atmosphere while serving as an insulator. This can allow electrical clearances and spacing inside transformers to be reduced to less than that required for strictly air-cooling, whether by natural convection or fan forced. Analyzing the properties of the liquid inside the transformers also allows the end users to keep track of the condition of the transformers. The most prevalent dielectric liquids used in transformers for petrochemical plants are mineral insulating liquid, natural esters, and synthetic ester liquids. Table 1 below summarizes a comparison of the differences between the different liquids.

A. Mineral Insulating Liquid

Mineral liquid type transformers currently dominate the market of new, large transformers, although several transformer manufacturers report that ester liquids are steadily becoming more popular. One major transformer manufacturer reported that approximately 60-70% of their new transformers contain mineral insulating liquid. Another reports the same for nearly 95% of their new transformers.

Mineral insulating liquid has been used in the industry for more than a century so there is better understanding on the characteristics of liquids and how to design, manufacture and maintain the transformers. Synthetic esters in comparison have been around for four decades and natural esters for two decades.

One main drawback of mineral insulating liquid is that it burns more easily than ester liquids, due to its lower fire point. Mineral insulating liquid has an approximate fire point of 320°F (160°C), while ester liquids have fire point of at least 572°F (300°C). Mineral insulating liquid can also cause environmental issues if it spills. Since mineral insulating liquid is not easily biodegradable, it can negatively impact water and wildlife in the vicinity, contaminate the soil around the spill, and transfer into groundwater systems or navigable waters[b].

[b] "*navigable waters*" with respect to an oil spill includes "…*shorelines, wetlands or areas that would adversely affect the natural resources of the U.S., and to provide for containment systems in lieu of only providing cleanup measures after a spill has occurred…"* This may include onshore areas. See ANSI/IEEE Std. 980™, 2013 Edition, *IEEE Guide for Containment and Control of Oil Spills in Substations* [7].

B. Ester Liquids

Unlike mineral insulating liquid, ester liquids can be either synthetic or natural. Synthetic esters are manufactured by reacting acids and alcohols to meet the desired characteristics, while natural esters are made from renewable sources like soybeans or canola. Natural ester filled transformers are sometimes referred to as "vegetable oil" filled transformers.

The key differences between natural and synthetic ester liquids are oxidation stability and pour points[c]. Synthetic ester liquids have oxidation stability that is similar or better than mineral insulating liquid and are used in transformers with breathers as well as those that are sealed. Natural ester liquids have very low oxidation stability and are only recommended for use in sealed transformers [8]. Synthetic esters also have an extremely low pour point (-56°C) compared to natural ester liquids (-18°C to -31°C), and therefore perform better in colder climates.

Ester liquids are considered environmentally friendly in comparison to mineral insulating liquids. They are "readily biodegradable," breaking down quickly into natural components. However, if there is a spill of ester liquid outside of a containment area in United States, these are required to be reported to authorities and currently cleaned up just the same as mineral insulating liquid. Environmental benefits, however, can be realized in the long-term remediation efforts.

TABLE 1
Mineral Insulating Liquid and Ester Liquids Comparison

	Mineral Insulating Liquid	**Ester Liquids**
Chemical Composition	• Carbon and hydrogen	• Carbon, hydrogen, and oxygen
Experience in use	• Used for more than a century	• Synthetic esters used since the 1970s • Natural ester liquids since the 1990s
Advantages	• Older technology used in extra high voltage transformers • Widely understood maintenance procedures • Established test methods and vast records on test data • Relatively inexpensive • Field engineers and technicians have extensive experience in handling the liquid	• High fire safety • Environmentally friendly • Improve life of insulation system permitting for life of transformer and/or higher loading • Cost savings can be achieved by reduced/eliminated fire suppression systems, closer spacing, simplified containment system, and smaller, lighter transformer
Disadvantages	• Burns significantly easier than ester liquids • Risk of pool fires • Require higher precautions for fire safety • Are not environmentally friendly when spilled • Cost of fire separation system; civil engineering and space can be significant	• Limited experience in maintenance procedure • Newer standards with minimal test data • More expensive than insulating liquid oil • Field engineers and technicians have limited experience in ester liquids and must rely on expertise of the ester manufacturers
Additional differences	• Although esters have different dielectric properties, such as the dielectric constant, greater alternating current withstand and impulse breakdown than mineral insulating liquid, for voltages up to 35 kV, there are typically either minor, or no physical design differences within the transformer. • Ester liquids have different thermal characteristics compared to mineral insulating liquid. The kinematic viscosity of ester liquids is higher than mineral insulating liquid, hence the liquid flow is slower in a transformer compared to mineral insulating liquid. • Ester liquids can operate at higher top liquid temperature and transformers can be designed to operate at higher temperatures allowing reduction in size and weight of the transformers and higher load capacity without shortening the life of the transformer. • Mineral insulating liquid has high oxidation stability and can be used in sealed and free breathing transformers. Synthetic ester liquids have high oxidation stability and can be used and handled in a similar manner as mineral insulating liquid. Natural ester liquids are recommended only for sealed transformers due to low oxidation stability.	

Moisture is a key property that contributes to the degradation of cellulose insulation inside the transformer. Ester liquids have a much higher moisture tolerance than mineral insulating liquid; as a result, they can absorb more water with little reduction in breakdown voltage as compared to mineral insulating liquids. Because esters hold more water than mineral insulating liquids, less moisture is available to contribute to the continuous breakdown of cellulose material. This helps extend the life of the transformer insulation.

It should also be noted: there are differences in moisture saturation values between natural and synthetic esters. Synthetic esters possess more ester linkages and therefore have a higher saturation value and can hold more water than can natural esters.

The chemical structure of ester liquids is different than mineral insulating liquids, so they have different dielectric and thermal properties. Mineral insulating liquids have a lower viscosity than ester liquids, which must be taken into consideration in the thermal design of the transformer.

Power factor, insulation resistance, and dissolved gas analysis of ester liquid type transformers are also different than that of mineral insulating liquid insulated transformers. This may be a concern initially with maintenance personnel who are accustomed to mineral insulating liquid transformer data. This is to be expected as the chemical makeup of ester liquids is different than that of mineral insulating liquids.

Ester liquids are typically more expensive at the outset than mineral insulating liquid, however the total cost of a substation may be lower due to reduction in costs of containment and fire suppression systems.

[c] "*pour point - the lowest temperature at which a liquid can be observed to flow under specific conditions"* [6].

IV. FIRE CONCERNS

A. Fire Causes

As mentioned, transformers are reliable and rarely fail; but even when they do, there is rarely a fire. CIGRE WG A2.33, Guide for Transformer Fire Safety Practices, Section 9.2.2 [9] states that, "Oil Impregnated Paper [OIP] bushings are the single largest cause of transformer fires." Other types of bushings have lower failure rates. Cable termination failures in cable termination boxes and on-load tap changer (OLTC) failures can also cause transformer fires. Unmitigated internal electrical arcs in the tank may lead to a tank rupture resulting in a release of oil mist and an oil spill fire. An internal electrical arc can generate a temperature that surpasses 1000 °F (540° C), which can then ignite the mineral insulating liquid.

B. Probability

It is not easy to establish an accurate probability of a transformer fire based on empirical data. Incidents like fires in plants are not widely publicized or shared. One source of transformer fire probability is provided by the CIGRE organization, based in France. Chapter 3 of CIGRE WG A2.33 [9] discusses the probability of transformer fires. The investigation in this guide covers ten countries, thousands of transformers, and hundreds of thousands of years of transformer service. The summary in Section 3.3 [9] states that the average probability of a major failure is about 1% per transformer service year. Section 3.3 [9] also states that approximately 10% of serious transformer failures result in a fire. CIGRE [9] points out that, for transformers equal to or greater than 10 MVA, and equal to or greater than 66 kV, there is an accumulated probability of a mineral insulating liquid transformer fire on average of 4% per transformer over a typical service life of 40 years. In the CIGRE brochure [9], it was noted that no fire incidents have been reported in 30+ years on transformers filled with ester liquids.

IEEE Std. 979, Table A.2 [1], indicates that mineral insulating liquid transformer fire frequency ranges from 0.025% to 0.09% per year for transformer voltages of 69 kV to 500 kV. This means the probability of a fire occurrence ranges from approximately 1% to 3.6% per transformer over a 40-year service life. Per FM 5-4, Section 1.2 [3], loss statistics indicate—as CIGRE [9] does—that about one in ten transformer failures results in a transformer fire. While these fire-probability numbers seem high, this is the information currently available. What is known is that even though the probability of fire is very low, it can occur, and this should not be ignored.

Fig. 1: Mineral Oil Substation Transformer Fire
(Photo credit: Shutterstock)

C. Consequences

Burning transformers and/or transformer containment fires with burning insulating liquids can injure workers who are in the vicinity of a fire, especially if a tank rupture occurs. Smoke inhalation, burns, and/or injuries sustained from flying shrapnel are all possible. Even trained firefighters are exposed to heightened risks if a transformer fire occurs.

D. Equipment Repair and Replacement

A transformer fire exterior to the substation puts the equipment inside the building at risk. Obtaining and replacing a large transformer is very difficult, and if the substation and switchgear inside are involved in the fire, then the situation becomes much more costly. Repair costs vary widely, depending on the extent of the damage. The repair or replacement cost of substations and associated transformers could vary from tens of thousands to millions of dollars. Critical equipment and other structures in the area adjacent to the transformer and substation can also be damaged.

E. Other Costs

In addition to electrical equipment replacement or repair, transformer fires can result in costs not directly related to electrical equipment. Unplanned downtime while replacement equipment is procured and installed can last for many months or longer. Unplanned partial or complete shutdowns of electrical systems can cause process disruptions, which can affect one or more process units or the entire facility. If a fire incident affects multiple process units, the incurred costs escalate quickly, due to the unplanned shutdown and the effect on the rest of the plant's production. If the insulating liquids spill, then the environmental clean-up costs can be extensive as well.

Of course, none of the above consequences are desired nor are they acceptable: the importance of selecting the proper transformer liquid and strategically placing the transformer in relation to the substation cannot be overstated.

V. MITIGATION TECHNIQUES

Various techniques are used to limit the potential damage caused by an insulating liquid type transformer fire, as described in IEEE Std. 979 [1]. A few of the more commonly used mitigation techniques are:

1) Providing adequate spacing between transformers, their oil containment areas, and buildings;
2) Providing firewalls between transformers, their oil containment areas, and buildings; and
3) Providing automatic fire detection and suppression systems (such as foam or water fog) at the transformers.

Most refineries and petrochemical facilities in the U.S. typically use appropriate spacing, firewalls, or a combination of both. Automatic suppression systems are not widely used for distribution transformers.

A. Spacing Between Transformer and Building or Structure

There are two basic methods for determining minimum distances between transformers and buildings. The most common method is the prescriptive method, which uses spacing charts. However, the absolute distances shown in a table or chart may not always be possible or practical, nor do they provide adequate protection for all site conditions. The second method is the performance-based method, which is based on heat flux calculations; it can be used to determine adequate spacing, as it more accurately models the specific site conditions. When calculations are performed, closer or greater spacing may be required than shown in spacing charts. Performing the calculations may be more accurate, but it is more time-consuming and requires specialized skills and training.

IEEE Std. 979, Clause 7, Table 1 [1] contains guidelines for "spatial separation" between noncombustible/limited combustible buildings and mineral insulating liquid insulated transformers. Spatial separation is understood as a straight line of sight from the anticipated flame front (oil containment pit) to the building or structure. The guide allows less spacing if the building and transformer are separated by a two-hour rated firewall. Unfortunately, no further guidance or diagrams explaining how to achieve this reduced spacing are provided (see discussion on NFPA 850 [2] in this section). While no minimum spacing guidance is provided for transformers with less than 500 gallons of oil, a footnote to Table 1 of IEEE Std. 979 [1] lists items that should be taken into consideration when determining suitable spacing. IEEE Std. 979 [1] currently contains no prescriptive guidance on the spacing between buildings or structures and ester liquid type transformers. International model codes, such as the *International Building Code* [10] are used to determine the fire-resistance rating of the building's construction.

NFPA 850, Section 5.1.4 [2] contains prescriptive and performance-based recommended spacing methods. Table 5.1.4.3 [2] lays out guidelines for spatial separation between outdoor mineral insulating liquid, insulated transformers, and adjacent structures. The information in this table closely matches the information in IEEE Std. 979, Table 1 [1]. For transformers with less than 500 gallons of oil, NFPA 850, Section 5.1.4.6 [2] recommends a minimum of five feet of spacing between a transformer and the exposed structure. However, like IEEE Std. 979 [1], it does not contain prescriptive guidance on the spacing between ester-filled transformers and buildings. NFPA 850, Figure 5.1.4.3 [2] illustrates how to achieve the required spacing.

Spacing recommendations for mineral insulating liquid and less flammable liquid type transformers can be found in FM 5-4 [3]. This document contains recommendations for three different types of transformers:

1) Non-Approved FM liquid or transformers without robust tank construction, along with other criteria containing regular mineral insulating liquid;
2) FM Approved liquid (less flammable ester) in non-Approved transformers; and,
3) FM Approved transformers containing FM Approved liquid.

FM 5-4, Appendix A [3] defines an *FM Approved Transformer* as: *"A transformer filled with an FM Approved fluid, either naturally cooled or utilizing forcibly circulated cooling medium. The standard limits approval for the naturally cooled transformers rated from 5 to 10,000 kVA. The transformer includes electrical protection to clear high current as well as sustained low current faults. A pressure relief device and tank discharge strength prevent tank rupture under a low-level electrical fault."* Parameters for what constitutes a "*low-level electrical fault"* are not indicated.

FM 5-4, Section 2.3 [3] provides prescriptive spacing methods, all of which are intended to be implemented with spill containment. FM 5-4, Figure 3, and Table 5 [3] contain spacing recommendations between various types of transformers and various types of main building walls. Minimum spacing is provided for all three types of transformers, and the distances are between the transformer and the exposed walls of the buildings. For mineral insulating liquid type transformers, the information in Table 5 [3] closely matches IEEE Std. 979, Table 1 [1] and NFPA 850, Table 5.1.4.3 [2], but it also includes a minimum 15-foot spacing for transformers with less than 500 gallons of oil. Minimum spacing distance involves the horizontal spacing from the edge of containment to the building walls. Less spacing can be used if the building wall is a two-hour rated firewall. FM 5-4, Figure 3 [3], illustrates how to achieve this reduced spacing.

FM 5-4, Figure 4, and Table 6 [3] contain information on spacing and the extent of two-hour fire barriers for ester liquid and mineral insulating liquid transformers. Information is based on a two-hour fire barrier of concrete block or reinforced concrete located between the transformer and the building. These spacing requirements differ from those shown in NFPA 850 [2]. In FM 5-4, [3] firewall sizes are shown but without line of sight spacing, as is seen in NFPA 850 [2]. FM 5-4, Figure 4, and Table 6 [3] allow for less spacing when FM Approved transformer liquid (ester liquid) is used. FM uses the distance from the edge of equipment/containment (not the line of sight between equipment and building) to determine firewall size. FM 5-4, Section 2.3.1.1 [3] indicates that it is possible to reduce spacing when a three-hour firewall is used instead of a two-hour firewall.

B. Automatic Fire Detection and Suppression

Fire suppression must be provided when required. When not required, it should still be considered to protect people, assets, and business continuity.

IEEE Std. 979 [1] and NFPA 850 [2] both contain spacing recommendations, and each state that a fire suppression system is one factor to consider in reducing the spatial distance between the transformer and the substation building. While not widely used in facilities that house transformers that fall within the scope of this paper, automatic fire suppression systems may be used instead of fire barriers when adequate separation distances cannot be attained. The use of automatic fire suppression systems may allow containment structures or fire barriers to have lesser fire resistance ratings.

Fig. 2: Water Spray Transformer Fire Suppression System
(Photo credit: Shutterstock)

IEEE Std. 979 [1] lists several different types of fire suppression systems that can be used. Extinguishing systems include clean gaseous agents, water deluge systems, foam-water systems, and water mist systems. IEEE Std. 979, Section 8.1 [1] states that a three-hour fire rating should be used for containment systems, but a two-hour rating is acceptable with an automatic fire suppression system installed at the transformer(s). FM 5-4, Section 2.3.1.1 [3] provides further guidance by stating that a water spray protection system, together with at least five feet of distance between a transformer and a fire-rated or even a non-combustible wall, is an acceptable installation. If a suppression system is used, possible issues must be considered during system testing. Also, fire suppression system piping must not be installed in a manner that interferes with working spaces or access to the equipment. It is important to also have a maintenance plan in place for the fire suppression system.

C. Stone Flame Suppression

If a transformer firewall is the "belt," crushed stone or rock in a transformer yard is the "suspenders." Crushed stone or rock also has its limitations. Stone requires maintenance, such as removing dirt and other materials that fill necessary voids between the stones. IEEE Std. 979, Section 7.1 [1] allows the flame-suppressing stone ground cover to be used to reduce the spacing between the transformer and the building. Section 8.2 [1] states that when the level of oil is within 1.5 inches of the top surface of the stone, flaming combustion will occur; as a result, combustion pits should be designed so that the top surface of oil is at least two inches below the top surface of the stone. IEEE Std 979, Annex E [1] contains examples of fire protection analysis calculations, including the impact of crushed stone.

NFPA 850, Annex C.6.2 [2] discusses the testing done on an oil pit with crushed rock. Oil above the level of rock burned, but when the oil level dropped two inches below the top of the rock, the fire was extinguished. Neither NFPA 850 [2] nor FM 5-4 [3] suggests less spatial distance between a transformer and a building when crushed rock or stone in the transformer yard is used for fire suppression.

D. Owner Risk Assessment, Mitigation, or Acceptance

While spacing charts are valuable for several reasons, they are not the only way to determine the necessary spacing for every situation. IEEE Std. 979 [1] and NFPA 850 [2] both allow engineers to perform risk assessments, considering all factors when determining the spacing between substation buildings and liquid type transformers. There are several case studies [8] of high voltage power transformers filled with ester liquids that have simplified mitigations systems whereby distances between transformers, and transformers to buildings have been reduced with no fire suppression system or fire barrier system and a simplified containment system. FM 5-4 [3] and CIGRE WG A2.33 [9] both describe the many factors that may reduce the likelihood of a transformer fire. It stands to reason if an owner can reduce the likelihood of fire, then some of the more stringent spacing or firewall requirements might also be reduced.

IEEE Std. 979 Section, 1.3 [1] acknowledges, "*The minimum required level of substation fire safety and protection is based on the minimum requirements of governing authorities and on the level of risk the asset owner is willing to accept*." Clause 9.5 and Annex A, A.22 [1] provide information on risk-based economic analysis, and Clause 9.6 and Annex C, Clause C.6 [1] provide information on cost/benefit analysis.

NFPA 850, Chapter 4 [2] contains details on the Fire Protection Design Process, which can include a fire risk evaluation. One result of this process is the determination of whether the recommendations of NFPA 850 [2] are or are not acceptable to owners.

According to FM 5-4 [3], "*Adequate electrical protection, electrical testing, maintenance, and proper operation are key factors in reducing the risk of transformer explosions and fires*." FM 5-4 [3] recommends protection schemes for different types of transformers, along with recommendations for testing, maintenance, and operation. FM 5-4, Section 3.1 [3] includes diagnostic information that can help determine the health of a transformer. FM 5-4, Section 3.4 [3] discusses transformer aging and suggests how to detect when a transformer is reaching the end of its life.

CIGRE WG A2.33, Section 1.1 [9] states that preventing a tank rupture and properly containing oil after a spill are both critical steps in limiting the damage caused by transformer failure and in reducing the risk of a major transformer fire. CIGRE Chapter 6 [9] details many ways to mitigate the risk of transformer fires, in addition to the other techniques described in this paper. Common methods include:

1. Enhanced maintenance processes
2. Proper operating practices
3. Electrical overcurrent and overvoltage protection
4. Pressure relief and over-temperature protection
5. Use of less-flammable insulating liquids
6. Tank design
7. Pressure venting
8. Component choice (e.g., bushings, etc.)

Operating companies that utilize common mitigation methods should be able to minimize transformer failures and resulting fires. Accordingly, operating companies typically consider these factors when performing risk assessments.

E. Retrofilling Transformers with Less Hazardous Liquids

If a mineral insulating liquid type transformer is currently in operation, a cost-effective way of making the transformer safer is to retrofill the transformer with a less flammable liquid. Based on OSHA's Hierarchy of Controls, (Fig. 3), in transformer applications, the top level is elimination, (see Common Methods of Mitigation above), and the second level is substitution, specifically substitute a less hazardous material or process. Retrofilling a transformer with a less hazardous liquid meets this criterion and is therefore preferred over engineering controls or other mitigations.

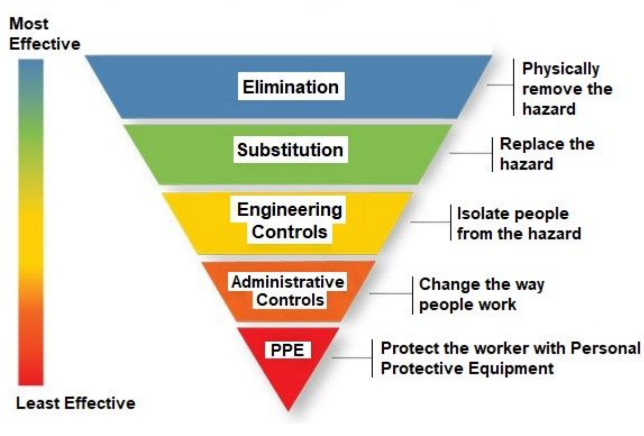

Fig. 3: Hierarchy of Controls Diagram
(Image credit: National Institute for Occupational Safety and Health National Institute for Occupational Safety and Health)

Retrofilling transformers involves the process of changing the insulating liquid (typically mineral insulating liquid) inside a transformer with an alternative liquid. The alternative liquid must be miscible and compatible and operate under similar conditions to the original insulating liquid. The first use of an ester liquid to retrofill a transformer was in 1979 when a synthetic ester liquid replaced polychlorinated biphenyl (PCB) in an arc furnace transformer. Since then, thousands of transformers have been successfully retrofilled with synthetic and natural ester liquids.

Fig. 4: A 47.8 MVA electrical arc transformer being retrofilled with synthetic ester liquid
(Photo credit: Charter Steel, Saukville, WI)

1. Benefits of Retrofilling a Mineral Insulating Liquid Type Transformer

The key benefits of retrofilling using ester liquids in transformers for mitigating fire hazards are:

a. Where spacing between existing substations and transformers need to meet installation and/or code requirements and the continued use of mineral insulating liquid would require a new or modified fire wall, new or updated fire suppression systems, or new/increased containment areas. By using an ester liquid, any or all the modifications described above may be reduced or possibly eliminated.

b. Switching the liquid from mineral insulating liquid to an ester makes the transformer more environmentally friendly.

c. For an in-service transformer in good condition, it could prolong the life of the insulation system.

2. Determine Candidacy of Retrofilling a Transformer

Determining whether a transformer can be retrofilled is critical and it is based on the type of insulating liquid in the existing transformer and the following information:

a. Ester liquids have different dielectric and thermal properties compared to mineral insulating liquids. The dielectric design of transformers is typically the same for transformers rated at ≤ 69 kV, so substitution of the insulating liquids may be possible with no other changes to the transformer. For higher voltage levels, some limitations may apply based on the analysis done by the transformer original equipment manufacturer (OEM) or a qualified individual.

b. The viscosity of ester liquids is higher than mineral insulating liquid. The top liquid temperature of the transformer may increase over the original design at full load; however, the aging rate of cellulose is slower in ester liquids, hence the higher temperature would not be detrimental to the cellulose material in the transformer.

c. Mineral insulating liquid is fully miscible with ester liquids, hence switching the liquid would not be a concern. However, it is not recommended to retrofill a silicone liquid type transformer with an ester liquid because the liquids are not compatible or miscible.

d. Additional information such as a load profile, liquid quality properties, physical condition of transformer, dissolved gas analysis, furans analysis, etc., should also be accessed.

It should be noted, however, none of these guidelines replace a proper evaluation by a qualified engineer.

VI. FUTURE CHANGES TO STANDARDS/PRACTICES/GUIDELINES

Several new standards, practices, and guidelines are being written and existing ones are being updated. At the time this article was written, the information referenced in the draft standards and guidelines below were accurate, however, the final documents may be updated:

1) IEEE Std. 979 (forthcoming revision) [11]: The equipment-to-equipment distance is being evaluated. In IEEE 979 – 2012 [1], the separation distance for a mineral insulating liquid type transformer is prescribed in Table 1 based on volume of liquid and separation distance. It is expected that the upcoming revision [11] will include more information on how to calculate proper spacing by using mass burn rate [d], heat of

combustion, and other preset variables of different fuels currently used by the Nuclear Regulatory Group.

2) IEEE C57.166 [12]: This document will provide guidelines on retrofilling of transformers. The annex on "Guide for Retrofilling Transformers with Ester Liquids" discusses the benefits, dielectric, and thermal design considerations, how to qualify a transformer for retrofilling, and a procedure to follow when doing so. The expected publication date for the standard is late 2022.

3) CIGRE WG D1.68 [13]: Various experts around the world are contributing knowledge and experience to this technical brochure. The scope of the group includes fire behavior comparisons between natural and synthetic esters and mineral insulating oils. The scope also includes an environmental impact comparison in the event of a spill of the three types of liquids.

[d] Mass burn rate: The mass-burning rate of a pool fire is the mass of fuel supplied to the flame per unit time, per unit area of the pool. Units are typically kg/m2/sec. Add ref. API RP 2FB below.

VII. RECOMMENDATIONS/CONCLUSIONS

Fire is always a concern with MV transformers and industry guidelines exist to provide minimum recommended spatial distances between liquid type transformers and substations. Unfortunately, the recommendations in the literature mentioned in this paper have differences. Most of the current recommendations for ester liquids are predominantly in FM 5-4 [3].

Various techniques exist to mitigate the fire problem and include spacing, liquids, and suppression systems/retrofilling existing transformers with ester liquids, etc. Different techniques have different benefits. New installations and existing installations will likely use different mitigations. Existing facilities may not comply with recommended spacing criteria and may need to apply other mitigation techniques to improve fire safety.

Some engineers believe that the industry recommended practices and guides have not changed for many years, and thus falsely assume, regardless of which cooling/dielectric liquid is used, transformer yards need to be designed as if all transformers contain mineral insulating liquid. A few of the transformer manufacturers consulted suspect that the lack of spacing guidance in today's practices and guides for ester liquids inhibits users from installing ester liquid transformers, because users have no industry standard(s) to follow. FM 5-4 [3] contains recommendations for spacing for less flammable liquid transformers, but it is not an industry consensus standard: certainly not everyone uses it, and many others may not even know that it exists.

Several different organizations and groups have tried for years to formulate a one-size-fits-all procedure to make the decision easier for engineers when deciding on minimum acceptable spacing. All the current guidelines and data are sound and valid, but within all these guidelines, certain items are addressed that the petrochemical industry may not have to regularly address. All the practices and recommendations in the U.S. today appear to be conservative—perhaps too conservative—in some situations. This makes sense: as anyone who has participated on industry panels can attest, a code or standards panel does not know all the different parameters involved for every installation, and never will. Thus, it is always best to err on the conservative side when establishing minimum and maximum standard values. This is where educated, experienced engineers are valuable. However, experience has shown that if given a choice, the responsible design engineer will more than likely apply one of the conservative separation values recommended in the existing guidelines whenever possible.

Hopefully the revised IEEE Std. 979 [11] will be useable by engineers in the refinery and petrochemical industry without needing to cross-reference between several documents. It will likely contain expanded guidance for the use of ester liquids. It is also highly likely the use of ester liquids will continue to grow and the spacing concerns between transformers and substations may become less than they are today.

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