Tennessee Valley Authority, Post Office Box 2000, Spring City, Tennessee 37381-2000

September 30, 2011

10 CFR 50.4

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Watts Bar Nuclear Plant, Unit 2
NRC Docket No. 50-391

Subject: WATTS BAR NUCLEAR PLANT (WBN) UNIT 2 – REQUEST FOR ADDITIONAL INFORMATION (RAI) GROUP 7 REGARDING "FIRE PROTECTION REPORT" (TAC NO. ME3091)

Reference: NRC letter to TVA dated September 14, 2011, "Watts Bar Nuclear Plant, Unit 2 - Request for Additional Information Regarding Final Safety Analysis Report Amendment Related to Section 9.5.1 'Fire Protection System' Group 7 (TAC NO. ME3091)"

The purpose of this letter is to respond to NRC's Group 7 RAIs pertaining to WBN Unit 1/Unit 2 Fire Protection Report contained in the referenced letter. This letter also responds to: (1) NRC questions received during a public meeting held in Rockville, Maryland, on August 31, 2011; (2) an email from NRC (Justin Poole, NRR) received on September 20, 2011; and (3) NRC's request for documentation that supports WBN's current audit frequency of the Fire Protection Program based on the results of past audits that was received during a teleconference conducted on September 12, 2011.

Enclosure 1 to this letter provides TVA's responses to NRC's requests/questions. Enclosure 2 provides the new Regulatory Commitments contained in this letter.

If you have any questions, please contact Gordon Arent at (423) 365-2004.

I declare under the penalty of perjury that the foregoing is true and correct. Executed on the 30th day of September, 2011.

Respectfully,

David Stinson
Watts Bar Unit 2 Vice President.

D030
A006
NRR

Enclosures:

1. Response to NRC's Request for Information Regarding "Fire Protection Report"

2. Regulatory Commitments

cc (Enclosures):

U. S. Nuclear Regulatory Commission
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ENCLOSURE 1

Response to NRC's Round 6 Request for Information Regarding "Fire Protection Report"

Reference: NRC letter to TVA dated September 14, 2011, "Watts Bar Nuclear Plant, Unit 2 - Request for Additional Information Regarding Final Safety Analysis Report Amendment Related to Section 9.5.1 'Fire Protection System,' Group 7 (TAC NO. ME3091)"

The following provides TVA's response to the referenced NRC requests for additional information (RAI) pertaining to the WBN Unit 2 Fire Protection Report (FPR). This enclosure provides TVA's responses to: (1) NRC questions received during a public meeting held in Rockville, Maryland, on August 31, 2011; (2) an email from NRC [Justin Poole, NRR) received on September 20, 2011; and (3) NRC's request for documentation that supports WBN's current audit frequency of the Fire Protection Program based on the results of past audits that was received during a teleconference conducted on September 12, 2011.

NRC's numbering system will be referenced to identify each question. Some NRC questions have been subdivided for clarity of response.

1. NRC Question (RAI FPR General-7)

The reviewers have found that not all RAI responses have been successfully incorporated into the FPR. Two examples:

1. *The TVA response to RAI II-8 (in the March 16, 2011, TVA letter) states, in part:*

   However, WBN does not reduce a fire watch from continuous to hourly roving in areas containing fire safe shutdown equipment for a unit in Modes 1 to 4, inclusive. WBN does reduce a fire watch from continuous to hourly roving for areas where a fire would impact the units in Modes 5, 6, and core empty.

   The FPR will be revised to clarify that this reduction only applies to areas and equipment affecting the unit in Modes 5, 6, and core empty and does not apply to areas that affect the other unit while in Modes 1 to 4 inclusive.

   However, the FPR contains numerous locations where this change has not been made. Some examples:

   When either unit is in Modes 5 and 6 or core empty, roving fire watches may be used in lieu of continuous fire watches when approved by the Fire Protection Supervisor (or designee). Locations where a continuous fire watch would be required in Modes 1 - 4 may be combined and patrolled by a roving fire watch. [pg. II-47]

   ***NOTE 4**: With either unit in Modes 5, 6, or core empty, locations where a continuous fire watch would be required may be combined and patrolled by a roving fire watch when approved by the Fire Protection Supervisor (or designee). [pg. II-52]*

> ***NOTE 1**: With either unit in Modes 5, 6, or core empty, locations where a continuous fire watch would be required may be combined and patrolled by a roving fire watch when approved by the Fire Protection Supervisor (or designee). [pg. II-53]*

Other instances of this condition exist in the FPR.

2. *The TVA response to RAI FPR III-13 (in the May 6, 2011, TVA letter states, in part:*

   Part III, Section 4.7 is incorrect. The third paragraph should read: "The CCS [component cooling water system] system provides cooling for the following safe shutdown equipment per unit." (emphasis added)

   However, Part III, Section 4.7, of the FPR reads: The CCS system provides cooling for the following safe shutdown equipment per Unit 1: (emphasis added)

To resolve the problems with RAI response incorporation:

- ***[1]** Correct the FPR to bring it into alignment with these RAI responses in all instances.*
- ***[2]** Provide assurance that other, similar deficiencies with respect to modifying the FPR to align with other RAI responses have been found and corrected.*

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

[1] For example 1 above addressing fire watches:

The FPR, Part II, Section 13.0.A will be revised to read as follows:

Section 13.0.A, beginning-

The locations that a continuous fire watch is required are based on plant conditions existing at the time the fire watch is in place and modified as needed. Continuous fire watches will be restricted to patrolling one fire area except as noted below.

Continuous fire watches are only required when the affected unit is in Modes 1 (Power Operation) to 4 (Hot Shutdown), inclusive. A "roving" fire watch will cover the designated areas on an hourly basis in areas where only the unit in Modes 5, 6, or core empty would be affected by a fire. If a fire in the area could affect both units then a continuous fire watch is required.

Section 13.A, last paragraph-

Situations may arise in which the system or equipment cannot be restored within the time specified by the Fire Protection Systems and Features Operating

> Requirements (Section 14.0). In such cases, an augmented compensatory action will be taken to ensure that a continuous fire watch does not go to different fire areas. The 15 minute requirements will still apply, but the continuous fire watch must remain within the same fire area. This augmented compensatory action is not required when only the unit in Modes 5, 6, or core empty could be affected by a postulated fire.

For other places in the FPR that refer to the change from continuous to hourly roving in Modes 5, 6, and core empty, the associated statement will be revised to state:

> With a unit in Modes 5, 6, or core empty, locations where a continuous fire watch would be required may be combined and patrolled by a roving fire watch when approved by the Fire Protection Supervisor (or designee) if the location only affects the unit in Modes 5, 6, or core empty.

This change will be made to:

13.0.B
14.1, Note 4
14.2, Note 1
14.3, Note 3
14.4, Note 3
14.8, Note

In other locations in the FPR, the following statement will be used:

> When a unit is in Modes 5 (Cold Shutdown), 6 (Refueling), or core empty, the locations where a continuous fire watch would be required may be combined and patrolled by one or more roving fire watch(es) provided the area only affects the unit in Modes 5, 6, or core empty. While a unit is in cold shutdown or refueling, there are fewer systems needed for maintaining cold shutdown and more people present that could detect and report a fire (General Employee Training includes how to report a fire). Roving fire watches provide an adequate level of coverage for these systems by ensuring that potential fire hazards are detected and corrected in a timely manner to prevent fires from occurring, or if a fire were to occur, ensuring that timely action is taken.

This change will be made to the appropriate paragraphs in the following bases sections:

B.14.1
B.14.2.1
B.14.3
B.14.4
B.14.8

For example 2 above addressing CCS:

For example 2 above addressing Part III, Section 4.7 and the CCS system:

> "The CCS system provides cooling for the following safe shutdown equipment per unit."

An extent of condition was performed and no other instances of this were found. The corrections identified in this subsection will be submitted in the next FPR.

[2] A review of the FPR has been performed to identify and correct similar deficiencies that occurred when modifying the FPR to align with past RAI responses. The deficiencies that were identified during this review will be submitted in the next FPR. A summary table of the identified deficiencies is included in Attachment 1.

2. *NRC Question (RAI FPR General-8)*

The reviewers continue to identify problems with Information Quality Control and other inconsistencies in the FPR. Two examples:

[1] An important explanatory sentence was deleted from Part VI Section 3.26.1 [pg. VI-437]. With the change, this section now reads:

> ***Deviations:*** *The justification for intervening combustibles such as insulation on cables in trays and Thermo-Lag is documented in Part VII, Section 2.4.*
>
> *a. Wide range steam generator level*
> *b. Tank level for the condensate storage tank (CST) and refueling water storage tank (RWST).*
> *c. Reactor Coolant System (RCS) cold leg temperature (T_c).*
>
> *The justifications are documented in Part VII, Section 2.1.*

[2] A change was made to Part VI, Section 3.22.2.1 [pg. VI-363] to add a protected cable to analysis volume AV-041M. However, summary Table I-1 was not updated to reflect this change.

[3] Perform an information quality and consistency review on the FPR and incorporate the results.

TVA Response:

[1] Part VI Section 3.26.1 will be revised to read:

> **Deviations:** The following instrumentation has not been provided in the Auxiliary Control Room:

a. Wide range steam generator level
b. Tank level for the condensate storage tank (CST) and refueling water storage tank (RWST).
c. RCS cold leg temperature (T_c).

The justifications are documented in Part VII, Section 2.1.

The justification for intervening combustibles such as insulation on cables in trays and Thermo-Lag is documented in Part VII, Section 2.4.

[2] Part I, Table I-1 will be revised to show that Fire Area 16, Room 757.0-A5 contains fire wrap.

This change will make Part VI, section 3.22.2.1 consistent with Table I-1 for analysis volume AV-041M. Table I-1 will be re-reviewed as part of the as-constructed FPR to ensure consistency with the remainder of the FPR.

The corrections identified in the FPR Part VI, Section 3.26.1, subsection [1] and Part I, Table I-1, subsection [2] will be submitted in the next FPR.

[3] As previously stated in letter item No. 1, a review of the FPR has been performed to identify and correct similar deficiencies that occurred when modifying the FPR to align with past RAI responses. The deficiencies that were identified during this review will be submitted in the next FPR. A summary table of the identified deficiencies is included as Attachment 1.

3. ***NRC Question (RAI FPR I-3)***

In the revised summary Table I-1, a number of rooms are indicated as having both required manual actions (and repairs) and no fire safe shutdown (FSSD) equipment installed. Examples include: 713.0-A10, 713.0-A17, and 737.0-A10.

[1] *Provide a technical justification for this configuration or correct the Table.* ***[2]*** *Provide assurance that other inconsistencies between the summary Table and the balance of the FPR have been identified and corrected.*

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

[1] A review of the safe shutdown analysis determined that the three rooms 713.0-A10, 713.0-A17 and 737.0-A10 do not have any FSSD equipment or cables in them and there are no operator manual actions (OMAs) or repairs required for a fire in the rooms.

Room 713.0-A10 is part of analyses volumes AV-024 and AV-025C which also includes fire zones 713.0-A1A4 and 713.0-A1AN. Fire zones 713.0-A1A4 and 713.0-A1AN contain FSSD components; and a fire in either of these zones require OMAs and/or

repairs, but 713.0-A10 does not contain components required for FSSD; therefore, a fire in the room will not result in an OMA/repair, nor are there any OMAs/repairs that are required to be performed in this room due to a fire elsewhere.

Room 713.0-A17 is part of analyses volumes AV-025C and AV-026 which also includes fire zones 713.0-A1B and 713.0-A1BN. Fire zones 713.0-A1B and 713.0-A1BN contain FSSD components and a fire in either of these zones require OMAs and/or repairs, but 713.0-A17 does not contain components required for FSSD; therefore, a fire in the room will not result in an OMA/repair, nor are there any OMAs/repairs required to be performed in this room due to a fire elsewhere.

Room 737.0-A10 is part of analysis volume AV-113 which consists of rooms 729.0-A11 and 737.0-A10. Room 729.0-A11 contains FSSD components, but does not contain any significant ignition sources nor quantity of combustibles that would damage any FSSD components; however, it is assumed that a postulated fire in the room could damage components and require OMA/repairs. Room 737.0-A10 does not contain any FSSD; therefore, no fire in the room requires an OMA/repair nor are there any OMAs/repairs required to be performed in the room due to a fire elsewhere.

Table I-1 will be corrected to reflect that no OMAs or repairs are required for a fire in rooms 713.0-A10, 713.0-A17 and 737.0-A10 and will be submitted in the next FPR.

[2] As previously stated in letter item No. 1, a review of the FPR has been conducted for consistency between sections. Identified discrepancies have been corrected and will be included in the next FPR submittal. It should be noted that Table I-1 is subject to changes as modifications are completed. The as-constructed submittal of the FPR will document the plant configuration at the time of Unit 2 fuel load.

4. *NRC Question (RAI FPR* II-37.1.1)

The TVA response to RAI FPR II-37.1, in the August 5, 2011, TVA letter indicates that the FPR would be modified to provide requirements for inaccessible areas outside of containment.

However Part II, Section 14.1.2.b of the FPR is not clear that it applies only to inaccessible areas. Modify the text to indicate this, or explain the difference in applicability between 14.1.2.b and 14.1.1.

This RAI may involve an update to the FPR to incorporate the response to the RAI..

TVA Response:

FPR, Part II, Section 14.1.2.b will be revised to specify that the section applies only to inaccessible areas outside of containment, as defined by the FPR, Part II, Section 5.0. Wording similar to the following will be used:

With any of the required Function A fire detectors in a fire detection zone identified on Table 14.1 inoperable in an inaccessible area outside containment, within eight hours, restore the inoperable equipment –OR– establish a roving fire watch once per 8-hours.

The basis for this section was previously revised to state "inaccessible area outside containment" in the FPR that was submitted in TVA's letter dated August 15, 2011.

5. *NRC Question (RAI FPR* II-44.1)

The TVA response to RAI FPR II-44, in the August 5, 2011, TVA letter, provides the basis for B.14.2.f, specifically, "The TIR [Testing and Inspection Requirements] bases, B.14.2.f, calls for this testing to compare the friction loss characteristics of the piping to previous tests."

Additionally, B.14.2.f states, "Any flow test that results in unacceptable deterioration of available flow and pressure shall be fully investigated."

- *[1] Provide the technical justification that demonstrates that, since the licensing of Unit 1, there has not been an "unacceptable degradation" in friction loss characteristics based on the testing described by B.14.2.f.*
- *[2] Provide a summary of the representative testing and discussion of how the results since licensing of Unit 1 demonstrate that the flow characteristics of the piping system are capable of providing for flows representative of those expected during a fire.*
- *[3] Describe the criteria used in making the determination of "unacceptable deterioration."*

TVA Response:

[1] The response to question number 10, RAI FPR VII-2.6.1, provides a summary of the review of the testing performed since licensing of Unit 1 and concludes that the system has not experienced an unacceptable degradation due to friction loss characteristics.

[2] The testing performs the following:

1. Removes the isolatable raw service water (RSW) loads from the system.
2. Starts two electric fire pumps (e.g., one from one unit and train and another from the other unit and other train).
3. Provides a flow equal to the non-isolatable RSW loads to ensure this load is on the system during testing. If the non-isolatable RSW load begins using water during the test, it adds an element of conservatism to the test results.
4. Performs a flow test of specific points on the system. These are the same points for each test. The test suggests the placement location of the instrumentation to attempt to have consistent data from year to year.

The System Description, N3-26-4002, "High Pressure Fire Protection System," summarizes the anticipated system capability based on piping condition using raw water. The response to Letter Item # 6, RAI FPR II-44.2, provides a discussion of how the Unit 1 testing demonstrates that the system is capable of providing flows representative of those expected during a fire.

[3] The engineering calculations, as summarized in the System Description, N3-26-4002, "High Pressure Fire Protection System," states that for the 40-year life of WBN, the hose stations on the roof of the Auxiliary Building will not be able to achieve a flow of 500 GPM at a residual pressure of 65 PSIG. This calculation is based on piping degradation that would happen after 40 years. It is expected that the piping conditions after 40 years of use will result in a coefficient of roughness of C=55 and a reduced pipe diameter of 0.8 inches. So based on:

1. the piping being installed for over 30 years,
2. the system testing is verifying the expected 40-year life of plant calculations, and
3. the hose stations of concern, in accordance with the System Description, have passed the acceptance criteria. (Note: The Auxiliary Building roof hose station has been re-tested from the last performance when it was discovered the measurement and test equipment was out of calibration. This re-test passed the acceptance criteria, but a corrective action document, Service Request 434337, was initiated to address the anticipated future failure.)

It is evident there has not been any unacceptable deterioration of the system since Unit 1 licensing, only anticipated system changes.

There is no formal definition of "unacceptable deterioration." As long as the system is still capable to perform its intended function and still exhibits the ability to continue to perform its intended function, "unacceptable deterioration" is based on engineering judgment.

6. ***NRC Question (RAI FPR II-44.2)***

The TVA response to RAI FPR II-44, in the August 5, 2011, letter, states: "The hose station flow paths from the main header are hydraulically separate from the main header to sprinkler flow paths and thus the hose stations do not impose hydraulic loads on the sprinkler paths."

Page VIII-40 of the FPR states: "Adequate fire fighting water requirements are considered to be the calculated flow and pressure to provide flow and pressure to meet suppression system design basis, including hose stream allowance and unisolated RSW [raw service water] loads."

The RAI response is inconsistent with the FPR, since the FPR states that the hydraulic calculations consider not only the hose station loads, but also the unisolated RSW loads. Since the hose and RSW loads are considered in the calculation, they also need to be considered in the testing.

Describe how the flow tests performed at WBN account for the additional flow for the fire hoses and the unisolated RSW loads.

TVA Response:

The capability to meet the total flow requirements is established by the flow calculation rather than the flow test. The calculation addresses the total flow to the hydrants, sprinklers, and/or hose stations and unisolated raw service water (RSW) loads. The calculation is based on the flow expected during a fire from sprinkler heads over a 1500 sq. ft. area, which results in a total flow just under 500 gpm for the worst case location in the Auxiliary Building. The calculation also assumes a 500 gpm hose allowance at the sprinkler system flow control valve and 105 gpm of unisolated RSW flow. The calculation evaluates the various areas/elevations of the buildings to demonstrate the capability to meet the total flow requirements for a single fire in any area/elevation containing FSSD equipment.

The purpose of the hydraulic flow test is not to demonstrate the capability to meet the total flow requirements but instead to trend the system for any unexpected changes in the supply piping. The calculation established the worst case locations for each type of load within the systems and determined the locations at which the flow in the future is most likely to drop below the acceptable flow rate due to system degradation (i.e., corrosion). The historical flow test results along with the most recent test data are then used to trend the flow in these representative flow paths so that TVA can predict the need to correct degradation before the ability to mitigate fires is impacted. Since the purpose of the testing is to trend degradation in the individual flow paths, it is not necessary to simulate the total flow (i.e., sprinklers plus fire hose flow from hose stations or hydrants) during the test.

As stated in the referenced RAI response, the system flow is supplied from large main headers. The total flow through the main headers is relatively small and is not expected to be a limiting factor at anytime during plant life. The flow path(s) for the main header(s) to the sprinklers is separate from the flow path for the main header(s) to the hose stations and thus it is not necessary to test the sprinkler flow paths at the same time as the hose station flow paths are tested. The flow test does include a 105 gpm flow to simulated RSW loads. The simulation of hose station flow and/or unisolated RSW loads is not a requirement as discussed above; however, the concern of RSW loads on the fire protection water supply during a fire resulted in including these loads during testing. This unisolated RSW demand is 105 gpm, which is insignificant since two 1590 gpm pumps are supplying the system at this time. All sections, except for the one section that tests the diesel fire pump supply piping, of the hydraulic testing at WBN account for the unisolated RSW loads by setting up a surrogate flow equivalent to the unisolated RSW loads at a fire hydrant at a location which is relatively remote from a hydraulic standpoint from the water supply (two electric fire pumps). Thus, if any of the unisolated RSW loads do place a demand on the system during testing, this demand is in addition to the surrogate demand, and adds an element of conservatism to the test.

7. ***NRC Question (RAI FPR II-46)***

Part II, "Fire Pump Inoperability and Compensatory Measures" Table of the FPR, appears to be inconsistent with the configuration of the plant.

Based on the Part II, Section 12.1, there are four electric motor driven fire pumps (EMFPs) and there is one diesel fire pump (DFP).

Examples:

- *Column 14.2.2 in the Table shows two EMFPs, one operable, one inoperable. What is the presumed status of the other two EMFPs?*
- *Table column 14.2.3, states one DFP operable and two inoperable, whereas 14.2.3 of the text stays, "With no electric driven pumps operable. . ."*

Explain the discrepancy between the number of EMFPs in the Table versus the other information provided in the FPR.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

TVA agrees that the duplication of the Operating Requirements (OR) in the Section 14.2 text and table could be confusing and could lead to errors. Thus, since this is a duplication of information, the table in the FPR, Part II, Section 14.2 will be removed. The removal of this table addresses the concern as to the discrepancy between the number of pumps and relies on the descriptive paragraphs in Section 14.2 to address the number of pumps required.

TVA also agrees there may be confusion due to the fact that there are four electric driven pumps with only two of them required for fire protection operability purposes. In order to address this possible confusion, the following paragraph will be added after the first paragraph in Part II, Section 12.1:

> The WBN fire protection system has four electric driven pumps and one diesel driven pump. As defined in Section 14.2.a below, fire protection Operability is based on only two of the four electric pumps and the diesel driven pump. The other two electric driven pumps are considered spares for fire protection purposes. The four electric pumps and associated main piping headers are ASME Section III, seismic class I available for supplying auxiliary feedwater during a design basis event (i.e., Flood Mode). During Flood Mode two electric pumps are aligned to each train header. Details of the Flood Mode are documented in several places in the FSAR such as Section 2.4.14.2, "Plant Operation During Floods Above Grade." The ASME and seismic requirements are beyond the requirements of the NFPA Code and are not required for fire protection purposes.

The changes contained in this item will be submitted in the next FPR.

8. ***NRC Question (RAI FPR II-47)***

A change was made in Part II of the FPR to delete TIR 14.10.n.

Explain this change and provide a technical justification for the deletion of TIR 14.10.n.

TVA Response:

Testing and Inspection Requirement (TIR) 14.10.n was erroneously removed. The testing is performed by a Surveillance Instruction (SI) with references to Technical Specification (TS) Surveillance Requirements (SR); however, the SI did not properly reference the TIR. SIs were required to reference the test requirements being implemented, and the omission of the TIR in the SI was an error. The lack of a reference in the TS SR resulted in the assumption the TIR was not needed. To correct the procedures, a corrective action document, Service Request 433266, has been initiated.

Thus the reference to the TIR will be added to the SI and the TIR will be added back to the FPR by adding the following:

ITEM NO.	TYPE OF SYSTEM/COMPONENT	FREQUENCY	TESTING/INSPECTION REQUIREMENT (TIR)	NOTES
14.10.n	1-FCV-3-116A 1-HS-3-116A/C 1-XS-3-116A 1-FCV-3-116B 1-HS-3-116B/C 1-XS-3-116B 1-FCV-3-126A 1-HS-3-126A/C 1-XS-3-126A 1-FCV-3-126B 1-HS-3-126B/C 1-XS-3-126B 2-FCV-3-116A 2-HS-3-116A/C 2-XS-3-116A 2-FCV-3-116B 2-HS-3-116B/C 2-XS-3-116B 2-FCV-3-126A 2-HS-3-126A/C 2-XS-3-126A 2-FCV-3-126B 2-HS-3-126B/C 2-XS-3-126B	18 months	Verify with the hand switch in P-Auto and the transfer switch placed in the Aux position that the FCV will automatically open on low level in the CST.	

In addition, the following bases will be added to the FPR, Part II for this TIR:

B.14.10.n TIR 14.10.n verifies every 18 months the remote switches for P-Auto operate correctly when the associated transfer switch is in AUX. This testing is consistent with the surveillance requirements for these switches (reference Technical Specification SR3.3.2, 3.3.3, 3.3.4, and 3.7.5)

The changes contained in this item will be submitted in the next FPR.

9. ***NRC Question (RAI FPR V-13.1)***

TVA's response to RAI FPR V-13 (in the August 5, 2011, TVA letter) indicates that there are no differences between the t=0 definition for fires where the reactor trip is performed from the main control room and where an automatic reactor trip is caused by the fire.

However, the FPR still defines t=0 as the time when the reactor is tripped from the Main Control Room.

Revise the FPR to reflect the definition of t=0 as described in the TVA RAI response. Additionally, the reviewers noted that TVA also provided additional information referencing Appendix E of Nuclear Energy Institute document NEI-00-01, Revision 2. This Appendix has not been endorsed by the NRC.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

Part V, Section 2.2.2 of the FPR will be revised and submitted in the next FPR. It will read as follows:

2.2.2 Operator Locations Prior to Initiating Manual Actions and t=0 Definition

For the purposes of developing the safe shutdown procedures, all operators performing manual actions are dispatched from the main control room for fires in most plant locations, or from the Auxiliary Control Room for Control Building fires. The basis for dispatch locations is that the operators must obtain the operator-specific safe shutdown procedures from these locations.

There are two scenarios for determining the time at which a reactor is tripped. One scenario is that the fire develops to a point that it damages equipment that will initiate an automatic reactor trip. The second scenario is that the MCR staff trips the reactor after assessing the fire and determining that tripping the reactor is necessary. The time at which the reactor is tripped is defined as t=0.

There are no differences in the actions or timing requirements following t=0 for the two scenarios. This is because a fire that could grow to the point of causing damage that results in an automatic reactor trip would have been assessed by plant personnel as a challenging fire with the potential to damage structures, systems, or components necessary for safe shutdown. The decision to trip the reactor manually would have been reached prior to or about the same time as fire damage actually causing automatic reactor trip.

Industry test data indicates that fire induced circuit failures will not occur immediately upon exposing cables to fire effects. Damage from an exposure fire to safe shutdown components or circuits is not expected to occur for at least 10 minutes after confirmation by plant personnel.

Fire locations subject to high energy rapidly developing fires (e.g., electrical board rooms and transformer rooms) do not contain cables or equipment whose failure could initiate automatic reactor trip. The control room is alerted of a fire in its early stages either by the fire detection system or as a result of visual observation by plant personnel. The operator's initial response includes:

a. Initiate plant fire alarms
b. Notify Fire Brigade
c. Ensure fire pumps are running
d. Announce Incident Command Post location over PA system
e. Assemble AUOs in the control room if the confirmed fire is in the Auxiliary Building or either Reactor Building (AUOs assemble at the Auxiliary Control Room if the fire is in the Control Building).

The time requirements for completion of manual operator actions are based on defining the initiating time t = 0 as the time when the reactor is tripped. This definition of the analytical t = 0 is appropriate because the manual actions are required to stabilize the plant or maintain it in a stable condition after reactor trip. The manual actions are not required to maintain the operating status of plant equipment prior to tripping the reactor because the reactor is considered to be in a stable operating condition prior to reactor trip. Once a trip is initiated, either automatically or manually, the preventive OMAs are performed to prevent spurious equipment operation and to ensure safe shutdown can be accomplished. Nearly all of the actions are preventive rather than reactive; they are performed per procedure rather than using process instrumentation or other indication to diagnose a need for the action.

There are very few situations where reactive action must be taken based upon fire damage to equipment or cables rather than trip initiation. In these situations the normal plant system operating procedure provides the reactive response while the FSSD procedure is preventive (action taken before fire damage causes a need for the action). For example:

1. Electrical power distribution board fire – The normal response and the safe shutdown action are the same; de-energize the board prior to extinguishing the fire.

2. Spurious start of a containment air return fan. The fan must be stopped. Existing system operating procedures require securing the fan (opening the breaker) which is the same action required for FSSD.

The reference to Appendix E of NEI-00-01, Revision 2 was only for additional information and will not be included in the FPR.

10. NRC Question (RAI FPR VII-2.6.1)

RAI FPR VII-2.6 requests, in part, that TVA: "Provide a detailed summary of the trending information for each of the monitored hose stations."

The TVA response to RAI FPR VII-2.6, in the August 5, 2011, TVA letter, directs the reader to the response to RAI FPR VII-2.3 for this information. However, examination of the response to RAI FPR VII-2.3 shows that it does not contain information on trending. The response to RAI FPR VII-2.2 does provide some discussion of trending, but does not provide the detailed discussion that RAI FPR VII-2.6 was requesting.

- *Provide a detailed summary of the trending results for each of the eight trending points identified in parts 1 and 2 of the TVA response to RAI FPR VII-2.2 from Unit 1 licensing to the present.*

TVA Response:

In TVA's July 22, 2011 response to the round 6 questions, the eight points discussed are:

Location	Valves
Auxiliary Bldg Roof	0-ISV-26-654 & -655
DGB Roof	0-ISV-26-565 & -566
IPS	0-ISV-26-1710 & -1711
Auxiliary Bldg Sprinkler System	0-FCV-26-143 and -322
Auxiliary Bldg Sprinkler System	0-FCV-26-151 and -326
Control Building Sprinkler System	0-FCV-26-211
DGB Hydrant	0-HYD-26-819
DGB Sprinkler System	0-FCV-26-167

A summary of the trending is:

General - This review does not show an adverse trend in relation to the calculated performance of this system. The last performance of these points tested does not indicate a need for more frequent testing with the exception of the Auxiliary Building Roof hose stations.

The plotting of the test data for each test point on a single semi-log Microsoft Excel graph does show variations, as expected. These variations are due to items such as the set point of the system pressure control valve, tolerance of the measurement and test equipment (M&TE) used, different personnel reading gauges, piping replacement, etc. The left hand point on each curve is established by measuring the static pressure at each location with the supply valve to that path closed (i.e., no flow condition). In this configuration, the system is supplying the simulated 105 gpm of un-isolated RSW flow but the system is basically in a no flow condition since the 105 gpm is insignificant compared to the system flow capability. The pressure at the test location is a direct result of the setpoint of the pressure control valve (PCV) at the Intake Pumping Station. Since the parameter of concern for the test is the change in pressure in the flowing condition versus the no flow condition, it is not critical that the PCV is at the same setpoint pressure for each test. This difference in PCV setpoint is evidenced by the static pressure in 1995 (i.e., 103 psig) versus the static pressure in 1996 (i.e, 130 psig).

The flow path is then opened. The flow rate through the path is measured along with the residual static pressure in the line. The resulting flow rate and residual pressure point for both the no flow and flowing condition are then plotted as shown on the attached plot. The Hazen-Williams equation for friction losses due to friction is:

$$h_{Lf} = 0.2083\,(100/C)^{1.85} * (Q^{1.85}/(d-2\Delta d)^{4.8655})$$

where: h_{Lf} = Friction loss
C = Surface characteristic roughness coefficient
d = inside pipe diameter
Δd = Reduction of inside pipe diameter due to corrosion product buildup
Q = Flow rate

A semi-log plot of the flow rate using a log axis to the 1.85 power would yield a straight line indicative of the friction induced pressure drop. It is noted that the attached semi-log plot uses a power of 2 instead of 1.85 due to the use of an Excel spreadsheet to create the provided figure. This plot is deemed to be sufficient close for illustrative purposes.

The parameter of concern for the high pressure fire protection (HPFP) system test is the change in pressure drop due to corrosion induced friction (i.e., h_{Lf}). Changes in friction induced pressure drop would be evidenced by a change in the slope of the line on the attached plot. As can be seen, the lines are basically parallel thus indicating very little change in pressure drop versus time.

An example of the test data is presented in graphical format in Attachment 2.

The replacement of the majority of the buried 12 inch B-train header in 2005 did not have an apparent affect on these points. What may be a more prevalent factor in the up and down variations of the graphed slopes is more likely the replacement of the Auxiliary Building interior loop piping. This interior piping has had different sections replaced since 1995 as pin-hole leaks developed. This piping is 6 and 8 inch and could have a greater effect on the testing considering the reduced roughness and increased internal diameter that the new piping would provide.

The following summarizes the results for each station:

Auxiliary Bldg Roof Hose Stations 0-ISV-26-654 & -655

Plotting of the data collected since 1995 shows the curves for the combined flow of both hose stations to vary for the different tests. In the middle years testing, the curves tended to have less slope indicating a positive trend which is possibly due to replacement of different segments of header piping in the Auxiliary Building. This flow point is one that failed the test's acceptance criteria, apparently due to an out of tolerance M&TE in 2010. A retest was conducted September 2011 and the point passed the acceptance criteria, but due to concerns about failure at the next performance, a corrective action document, SR 434337, has been initiated.

DGB Roof Hose Stations 0-ISV-26-565 & -566

Plotting of the data collected since 1995 shows the combined flow of both hose stations has shown a very steady trend based line slope. The latest test data indicates a positive trend. The failed M&TE was used on this test with no apparent affect.

IPS Hose Stations 0-ISV-26-1710 & -1711

Plotting of the data collected since 1995 shows the combined flow of both hose stations has shown a consistent trend. There has been an improvement since the 1995 original test but this test was skewed due to excessive flow during the testing resulting in an elevated Reynolds number and turbulent flow.

Auxiliary Bldg Sprinkler System 0-FCV-26-143 and -322

The trend has been fairly consistent since original testing. There is slight variation in the different slopes, but the 1995 and 2010 line slopes are very similar.

Auxiliary Bldg Sprinkler System 0-FCV-26-151 and -326

The trend has been fairly consistent since original testing. There is slight negative trend when comparing the 1995 and 2010 line slopes, but both match slopes for other years and appear to be within normal variation.

Control Building Sprinkler System 0-FCV-26-211

The trend has been fairly consistent since original testing. The slope for the 1995, 2001, and 2010 appear to match. The other years are within normal variation.

DGB Hydrant 0-HYD-26-819

The trend of the slope of these lines for these test points is very consistent, which is as expected since the supply piping for this hydrant is cement lined ductile iron pipe.

DGB Sprinkler System 0-FCV-26-167

The trend of the slope of these lines varies in the same range as other comparisons. The slope of the 1995 and 2010 performance is close with the 2010 indicating a slight improvement which is probably caused by M&TE tolerance.

11. NRC Question (RAI FPR VII-2.7)

During the July 12, 2011, public meeting, it was noted that there are pressure/flow tests required for American Society of Mechanical Engineers (ASME) Class 3 piping per ASME code. At the meeting neither TVA nor the NRC was able to determine in detail what these tests were, or whether they were being performed at the Watts Bar site.

- *Provide a summary of the testing performed on the high pressure fire protection Train A and Train B safety related headers because of their classification as ASME Class 3 piping. The summary should include, at a minimum, a description of each test, the test frequency, and acceptance criteria.*

TVA Response:

The buried Train A and Train B safety-related headers are classified as ASME Class 3 piping. This piping was constructed to ASME Section III and maintained to ASME Section XI as Class 3, not because they are used for an accident, but because they are used for the design bases event of flood mode at WBN to supply auxiliary feedwater. These headers do not meet the criteria to be part of the System Pressure Test Program (SPT) based on the criteria from ASME, Section XI, IWD-1210 which states:

> The examination requirements of this Subsection shall apply to pressure retaining components and their welded attachments on Class 3 systems in support of the following functions:
>
> (a) reactor shutdown
> (b) emergency core cooling
> (c) containment heat removal
> (d) atmosphere cleanup
> (e) reactor residual heat removal
> (f) residual heat removal from spent fuel storage pool

This piping is not part of the reactor residual heat removal system, but is a part of the emergency feedwater system, in accordance with American National Standard N18.2-1973, Section 2.3.1.2 and 2.3.1.3. The WBN FSAR discusses the piping classification in Section 3.2.2, which states:

> Fluid system components for the Watts Bar Nuclear Plant that perform a primary safety function are identified by TVA Classes A, B, or C (see Section 3.2.2.7 for HVAC Safety Classifications). These piping classes are assigned to fluid systems based on the ANS Safety Classes 1, 2a, and 2b, respectively, which are assigned to nuclear power plant equipment per the August 1970 Draft of ANSI N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants." Fluid system components, whose postulated failure would result in potential offsite doses that exceed 0.5 Rem to the whole body, or its equivalent to any part of the body, are identified as TVA Class D and are based on ANSI N18.2 (Aug., 1970 draft) Safety Class 3 and Regulatory Guide 1.26. The TVA piping classification system for WBNP does not conform strictly to the guidance of Regulatory Guide 1.26 (which was not in effect on the docket date for

the Construction Permit). The ANS safety classification of each component has been considered in the various aspects of design, fabrication, construction, and operation.

Thus, there is no ASME requirement to perform testing on this piping, since it is not scoped into the required safety functions listed in IWD-1210.

The HPFP Class 3 piping and components are a part of the augmented ASME program that WBN has established to test the active components (e.g., valves and pumps) in a manner similar to the ASME devices. The passive components, such as piping, are not tested specifically by the augmented program but by the individual programs which the passive components support. For the two buried headers, there are no valves or pumps.

The following is the testing the Train A and B buried headers do experience:

- The HPFP system, including these buried headers, is brought to system pressure at least once per week for periodic pump runs per the FPR, Part II, Section 14.2. This is not a formal test of the piping but it does serve to allow plant personnel to observe the piping at system pressure. Note that the ASME system pressure test requirement is to bring the piping to system pressure once per period (one-third of an Inservice Interval of 10 years; nominally every 3.3 years).
- The valves that isolate the buried trained headers are cycled once per year.
- The headers are flow tested at least once every 3 years as a part of the fire protection flow test of the hydrants, sprinklers, and hose stations, as discussed in Questions 5 and 10 above.

12. NRC Question (RAI FPR VII-18)

It is unclear whether there is fire detection in the tunnel of Fire Zone 692.0-A1B. A plain reading of Part VII, Section 8.3.3.4 of the FPR would indicate that, although there is no suppression, there is detection. However, both Table I-1, and Part VII, Section 3.1.1, indicate that there is no detection or suppression.

Clarify whether there is detection in the tunnel of Fire Zone 692.0-A1B.

TVA Response:

It is noted the question refers to Section 8.3.3.4, but it should have referred to Section 8.3.3.2. The fire detection system provided for 692.0-A1B does not extend into the tunnel. Section 8.3.3.2 will be revised to clarify that the tunnel from 692.0-A1B is not provided with detection or automatic suppression. However, as documented in Section 8.3.3.2, the reader is directed to Part VII, Section 3.1.1 where the lack of detection and suppression in the tunnel has been previously justified and documented. This change will be submitted in the next revision to the FPR.

13. *NRC Question (RAI FPR VII-19)*

A number of areas where a fire causes a manual action to be performed lack both detection and suppression. Examples of these areas are found in Part VII, Sections 8.3.14, 8.3.15, 8.3.18, 8.3.19, and 8.3.24 of the FPR.

Provide a description of the entry conditions for the manual action, since detection of the fire through automatic means is not available.

For example, how will the operators know to perform Operator Manual Action (OMA) 1016 (for a fire in room 729.0-A2, for example), without knowing a fire has occurred in the area?

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

The feasibility and reliability evaluations for Part VII, Sections 8.3.14 (Room 729.0-A1 – Unit 1 South Main Steam Valve Room), 8.3.15 (729.0-A2 – Unit 1 North Main Steam Valve Room), 8.3.18 (729.0-A10 - Unit 2 North Main Steam Valve Room), 8.3.19 (729.0-A11 - Unit 2 South Main Steam Valve Room), and 8.3.24 (729.5-A17 - Unit 2 Shield Building Vent Radiation Monitoring Room) have been deleted. An engineering evaluation for each of those rooms has been completed and will be documented in Part VII, Section 3.1 of the FPR. None of these rooms contain a significant quantity of in situ combustibles or any credible ignition source that would result in a fire that would require a shutdown on either of the units (see following evaluation of 729.0-A1 as example). These revisions will be included in the next FPR submittal.

Fire Area 12 contains two rooms (729.0-A1-Unit 1 South Main Steam Valve Room and 737.0-A6-Air Lock into 729.0-A1). Neither of these rooms is provided with detection or automatic suppression. Room 737.0-A6 only contains lighting and it is not required for fire safe shutdown nor would its failure require a unit shutdown. Room 729.0-A1 contains valves in the Feedwater and Main Steam systems (systems 1 and 3) that are required for normal operation and post fire safe shutdown. The other components (e.g. area radiation monitors, lighting, exhaust ventilation, etc.) are not required for fire safe shutdown nor would their failure require or cause a unit shutdown.

The two rooms are of reinforced concrete construction which is 12 to 36-inches thick and have fire resistance ratings of 2-hours for those barriers that separate the rooms from adjacent rooms in the Auxiliary Building and 3-hours from the Unit 1 Reactor Building. The walls that separate room 729.0-A1 from the Yard are minimum 24-inches thick, but are not assigned a fire resistance rating. Room 737.0-A6 has a floor area of 77-ft^2 and a ceiling height of 8-feet. Room 729.0-A1 has a floor area of 874-ft^2 and a ceiling height of 57-feet. An effective detection system is not viable due to the ceiling height and the high ambient temperature and humidity in this room.

The in situ combustible loading of 729.0-A1 consists of small quantities of lubricating oil in various valves and miscellaneous plastics associated with area radiation monitors, lighting, and small electrical control panels and boxes. The total combustible loading

results in a fire severity of less than 1-minute (insignificant). The in situ combustible loading in 737.0-A6 is due to the light covers and results in a fire severity of less than 1-minute (insignificant). There are no ignition sources in 737.0-A6. The only credible ignition sources in 729.0-A1 are the radiation monitors and valve motors (power circuits are de-energized when the valve is in its normal alignment). Neither of these are considered to be a significant ignition source (their failure would not damage any other component). Transient combustibles are controlled in accordance with combustible control zones identified on the Compartmentation drawings.

Failure of Feedwater and Main Steam valves would be detected by system instrumentation that would activate alarms in the Main Control Room to alert the operating staff of a problem and the staff would address the problem using normal plant operating procedures. There are no credible fires in Fire Area 12 that would require or cause emergency shutdown of either unit. Therefore, the lack of detection and automatic suppression does not significantly decrease the fire protection or safety of the plant and WBN requests approval for not providing detection and automatic suppression in Fire Area 12.

An extent of condition review has been performed and the results will be included in the next revision of the FPR.

14. NRC Question (RAI FPR VII-20)

There are inconsistencies in the level of detail provided in Part VII of the FPR regarding OMA Staffing Requirements. Two examples:

1. *Section 8.3.42.5 includes a relevant paragraph regarding OMAs 1022 and 1023, as Unit 2 OMAs. This paragraph is relevant since it provides actual demonstration time for the combination of actions for Unit 1 (mirror image actions) and describes that the OMAs occur are performed in the same room. This paragraph is followed by 12 paragraphs that are not related to the submitted evaluation.*

2. *Section 8.3.9.8 is only one paragraph with one sentence listing the operator and the actions that they are performing. Of the eight operators, only the seventh operator is performing the OMAs described in the evaluation. This paragraph lacks the useful description of the demonstration time for the combination of actions and a statement regarding the rooms that the OMAs need to be performed. This is especially relevant since OMAs 1016 and 1024 are described as performed in Room 737.0-A9 and OMA 1482 is described as performed in Room 713.0-A1B.*

Provide consistent level of detail for the Staffing Requirements sections of Part VII, Section 8 Evaluations. Include information regarding combination of actions that are performed by the operator or operators that are performing the OMAs evaluated.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

The OMA Staffing Requirements of the feasibility and reliability evaluations in Part VII, Section 8 will be revised to provide a consistent level of detail for each evaluation by eliminating the details of the Unit 1 OMAs. Staffing discussions will focus on the Assistant Unit Operators (AUOs) performing the evaluated Unit 2 and common OMAs and provide specific discussion of actions performed by those AUOs prior to or concurrent with the evaluated OMAs. Unrelated actions will be summarized to indicate that an adequate number of AUOs are available for all operator actions. These changes will be provided in the next FPR submittal. The revised version of sections 8.3.9.6 (8.3.9.8 from the August 15, 2011 submittal is now 8.3.9.6, as OMAs 1016 and 1024 are no longer required for 713.0-A1A) and 8.3.42.5 shown below are examples of the level of detail which will be provided for each of the staffing requirement sections in the next revision of the FPR.

8.3.9.6 Staffing Requirements for a Fire in Room 713.0-A1A

A fire in 713.0-A1A requires 18 Unit 1 actions requiring five AUOs and three Unit 2 actions (OMAs 1022, 1023, and 1482) requiring two AUOs for a total requirement of 7 AUOs. Therefore, the staffing of eight AUOs for the station is sufficient to accomplish all of the required Unit 1 and Unit 2 manual actions, if there is a fire in room 713.0-A1A.

a. One AUO will perform OMA 1482 to throttle seal injection flow in room 713.0-A1B within 60 minutes.

b. A second AUO will perform OMAs 1022 and 1023 to modulate steam generator #3 and #4 PORVs at the local N2 station in room 729.0-A15 within 60 minutes. These concurrent actions performed at the same location require no additional transit time.

8.3.42.5 Staffing Requirements for a Fire in Room 757.0-A9

A fire in 757.0-A9 requires three Unit 2 actions (OMA 1446, 1023, and 1022) performed by two AUOs and 46 Unit 1 actions performed by five AUOs for a total of seven AUOs. Therefore, the staffing of eight AUOs for the station is sufficient to accomplish all of the required Unit 1 and Unit 2 manual actions, if there is a fire in room 757.0-A9.

OMAs that are related to a fire in 757.0-A9 are as follows:

a. One AUO is required to operate 2-ISIV-1-403E2 (OMA 1023) and 2-ISIV-1-402E2 (OMA 1022) to control secondary pressure from the local N2 station in room 729.0-A15 within 60 minutes. These concurrent actions are performed at the same location with no additional transit time.

   A second AUO performs two important to safe shutdown OMAs. Unit 1 OMA 1411 in room 692-A1A within 20 minutes and Unit 2 OMA 1446 in room 772-A15 within 70 minutes.

15. NRC Question (RAI FPR VII-21)

There exists a conflict between Part VII, Sections 4.5 and 8.3.44.2, of the FPR.

Part VII, Section 8.3.44, includes OMAs required for safe shutdown. Part VII, Section 8.3.44.2, references Part VII, Section 4.5, for justification of why no detection is required in the Refueling Room, 757.0-A13. Part VII, Section 4.5 states as part of the justification for no detection: "A fire in the Refueling Room or in the adjacent rooms of Fire Area 10 will not impact FSSD capability." The quoted statement in Section 4.5 conflicts with the need for OMAs in 757.0-A13, Refueling Room.

Resolve this inconsistency between the sections of Part VII. Provide a technical justification for the lack of detection in the Refueling Room in the context of the need for OMAs in that area.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

This question is linked to Question 22, Sub-question [1] (RAI FPR VIII-22). The below response addresses both RAI FPR VII-21 and VIII-22, Sub-question [1].

The Engineering Evaluation documented in Part VII, Section 4.5 will be revised to provide additional justification for the lack of detection in the Refueling Room and New Fuel Storage Vault and this will also eliminate the need for the OMAs. Therefore Part VII, Section 8.3.44 is being deleted. These changes will be included in the next FPR submittal. The new Part VII, Section 4.5 is as follows:

4.5 LACK OF AUTOMATIC DETECTION IN 757.0-A13 (REFUELING ROOM) AND NEW FUEL STORAGE VAULT (741.5)

REQUIREMENT – Sections F.12 and F.13 of Appendix A to BTP 9.5-1 identifies that automatic fire detectors should be installed in the areas of new fuel and spent fuel pools.

DEVIATION - The refueling area (Refueling Room 757.0-A13 which includes the New Fuel Storage Vault, Spent Fuel Pool and Fuel Transfer Canal) is not provided with an automatic detection system.

JUSTIFICATION - The Refueling Room is part of Fire Area 10, but it is not provided with installed automatic detection. Standpipe and hose stations are provided in the room and in adjacent rooms. It is a large open area (floor area of 16,164-ft^2) with nominal ceiling height of 56-ft.

The only ignition sources that could impact a FSSD component or cable are the Train A and B Auxiliary Air Compressors. These compressors are required to provide backup air (to the Train A and B air header) if the normal air supply from the Station Air Compressors is unable to maintain minimum pressure on the air header. A fire involving

either of the Auxiliary Air Compressors (neither is in the zone of influence of the other) would not impact the normal air supply or the other Auxiliary Air Compressor.

A fire on Train A compressor could cause 0-FCV-32-82-A to close which would block air flow from the Station Air header to the Train A air header. The normal Station Air header would still be backed up by Train B air header supplied from the Train B compressor. A fire on Train B compressor could cause 0-FCV-32-085-B to close which would block air flow from the Station Air header to the Train B header. The normal Station Air header would still be backed up by the Train A air header supplied from the Train A compressor. Worse case fire induced failure would be loss on one train of auxiliary control air which can be handled by plant procedures without shutting down either unit.

Other FSSD circuits routed in conduits through the Refueling Floor area are outside the zone of influence of the compressors. Therefore, a fire in the Refueling Room or in adjacent rooms of Fire Area 10 will not impact on FSSD capability. Part VI contains the fire hazard analysis (FHA) discussion of the FSSD analysis for Fire Area10.

During normal operations, the in situ combustible loading for the Refueling Room and New Fuel Storage Vault is insignificant and results in an equivalent fire severity of less than five minutes. The combustible materials in the Refueling Room are widely dispersed which further diminishes the magnitude of a postulated fire. During an outage, the area is manned and any postulated fire from transient material due to refueling activities would be quickly detected and extinguished. The New Fuel Storage Vault is only accessible from the Refueling Room and that access is normally closed with a steel hatch cover. The cover is removed when new fuel is received and stored until needed for a refueling outage. There are no ignition sources in the New Fuel Storage Vault. Based on the insignificant in situ combustible loading during operations, high ceiling, large volume, good compartmentation, and lack of impact on FSSD, TVA requests approval for not providing automatic detection and suppression for the WBN Refueling Room.

16. NRC Question (RAI FPR VII-22)

A number of the evaluations in Part VII, Section 8 of the FPR state that a particular room does not have dedicated procedures for fire safe shutdown. One example is Section 8.3.45, which states in part: "Room 757.0-A14 does not currently have a dedicated procedure for fire safe shutdown."

The submitted FPR is intended to be the as-designed version of the FPR. Therefore, the statements should either include a reference to a commitment or be written as if the procedures have been completed, even if all the procedures are not yet completed. These statements indicate that it would be acceptable not to have a procedure.

Confirm that there will be procedures for these OMAs.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

TVA confirms there will be procedures for each affected room that address each OMA. The OMAs identified in the FPR are to be verified by walkdowns and documented in AOI 30.2 prior to fuel load. The statement that a room does not have dedicated procedures for FSSD will be deleted for the evaluations. These revised evaluations will be included in the next FPR submittal.

17. *NRC Question (RAI FPR VII-23)*

Part VII, Sections 8.3.86, 8.3.87, 8.3.88, and 8.3.89 [Accumulator Room 2, Fan Room 2, Unit 2 Lower Containment Instrument Room, and Outside Crane Wall (North), respectively], lack descriptions of fire detection, fire suppression, combustibles and ignition sources.

Provide the missing information. If detection is not available in the rooms, provide a technical justification that operators will have sufficient information available to know to initiate the OMAs.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

Engineering Evaluations will be performed for the four fire zones (2RA2 - Accumulator Room 2, 2RF2 - Fan Room 2, 2RIR - Instrument Room. and 2RO-N - Outside Crane Wall [North]) identified in NRC's request and will be added to Part VII, Section 3.1 of the FPR. These evaluations will be included in the next FPR submittal. The in situ combustible loading in each of these fire zones is insignificant, except for 2RO-N (fire load severity is low) and there are no credible ignition sources in the rooms. The major contributor to the combustible load (92%) in this zone is due to the expansion joint material. Transient combustibles are controlled in accordance with combustible control zones identified on the Compartmentation drawings. Therefore, there is no threat to FSSD components located in the room. The addition of detection and suppression in these rooms would not significantly increase fire protection of safe shutdown capability in the rooms.

TVA has performed a generic review for Unit 2 and identified all rooms in the Unit 2 Reactor Building without detection, but contains FSSD components. Additional information will be added to the next revision to the FPR to address these rooms.

18. *NRC Question (RAI FPR VII-24)*

Part VII, Section 8.3.10.5, of the FPR, discusses OMA 1275 in Fire Zone 713.0-A1B. In this section, travel time has been approximated for each of the operator manual actions.

Provide the technical basis for assuring that the travel time includes all likely locations of the Auxiliary Unit Operators where they could be at the beginning of the actions.

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

Recognizing that the AUOs could be working anywhere in the plant at the onset of a fire, one of the initial general fire response actions (prior to reactor trip) by the control room operator is to summon the AUOs to the control room (auxiliary control room for a Control Building fire) for a confirmed fire located in the Control Building, Auxiliary Building, either Reactor Building, or annulus. At t=0, AUOs assigned to Appendix R OMAs would be in the Main Control or Auxiliary Control Room where they would receive their specific assignments and procedures (see FPR Part V, Section 2.2, Safe Shutdown Procedures). OMA requirements vary depending upon fire location, and AUO tasks are not pre-assigned to individual AUOs. Since the AUOs come to the control room to receive their assignments, all travel times start from the control room.

Additionally, TVA is eliminating the use of approximate times and the symbol for "approximate." This change will be submitted in the next FPR.

19. NRC Question (RAI FPR VII-25)

Part VII, Section 3.1.1, of the FPR was changed to indicate more rooms within Fire Area 1 contain FSSD equipment. In particular, the following rooms were changed from "None" to "Yes" in the summary table: 674.0-A1, 674.0-A2, 692.0-A29, and 692.0-A30. Room 692.0-A18 was changed from "Yes" to "None."

The reviewers have identified the following inconsistencies:

- ***[1]*** *Room 674.0-A2 is indicated as containing FSSD equipment, but there is no evaluation provided for this room. Additionally, Table I-1 shows this room as having no FSSD equipment.*
- ***[2]*** *The new evaluation provided for rooms 692.0-A29 and -A30 (one sentence) is insufficient. Provide a level of detail equivalent to the other evaluations.*
- ***[3]*** *Part VII, section 3.1.1, was changed to add an evaluation of room 692.0-A23. However an evaluation for this room already exists in section 3.1.7.*
- ***[4]*** *The evaluations in Section 3.1.1 for rooms 692.0-A10, -A22, and -A23 are not indicated in Table I-1 (or Part VI for -A10).*

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

[1] Room 674.0-A2 does not contain FSSD components. Table 3.1.1 will be corrected to show "None" for this room.

[2] The evaluation in the FPR for rooms 692.0-A29 and -A30 will be revised as follows:

Transient combustibles are controlled in accordance with combustible control zones identified on the Compartmentation drawings. This would include posting a fire watch during the work process. The in situ combustible loading for each of these rooms is Insignificant and there are no significant ignition sources. The FSSD required cables are routed in conduits and the minimal fire hazards in the rooms would not be expected to endanger functionality of these cables."

[3] Part VII, Section 3.1.7, Fire Area 68, will be deleted and the appropriate places in Table I-1 and Section VI of the FPR will be corrected.

[4] Table I-1 has been corrected to refer to Part VII, Section 3.1 for rooms 692.0-A10, -A22 and -A23. As part of the extent of condition review, Part VI of the FPR has been revised to refer to Part VII, Section 3.1, for room 692.0-A10. Part VI of the FPR already referred to this reference for the other two rooms.

During the August 31, 2011 public meeting, it was discussed that room 692-A18 has no FSSD equipment, but the evaluation was originally retained. This evaluation will be removed in the next revision to the FPR.

The changes addressed in this item will be submitted in the next FPR.

20. NRC Question (RAI FPR VIII-21.1)

RAI FPR VIII-21 requested that TVA:

Identify the locations where combustible oil filled transformers are installed. Provide the locations to the level of detail of room subdivisions used to assemble analysis volumes (for example, room 692.0-A1 has been subdivided into 692.0--A1A1, -A1A2, -A1A3, -A1AN, -A1B1, -A1B2, -A1B3, -A1BN and -A1C).

The explicit intent of this question was to determine which portion of the subdivided areas houses the transformers with combustible liquid.

For example, Analysis Volume AV-005 in Fire Area 1 includes room 692.0-A1, which is subdivided into numerous areas including A1BN. A1BN is central to the entire area, and would be considered a "buffer zone." If transformers are located in this portion of AV-005, they have the potential to impact the volume analysis of Part III, Section 10.3.1. Specifically, Section 10.3.1 relies on Deviation Request 2.4 of Part VII of the FPR for the treatment of intervening combustibles. Combustible liquid filled transformers were not listed in Deviation Request 2.4, whereas much less significant combustibles were, such as plastics in junction

boxes. Therefore, even with enhanced suppression provided in the area, specific analysis of combustible liquid transformers should be included where they could represent an intervening combustible in such a "buffer zone."

[1] Provide the specific sub-area where each of the combustible liquid transformers are located. Area and analysis volume do not provide sufficient information regarding where in the plant these transformers are located. In particular, it appears that this detail was not provided (in the August 5, 2011, TVA letter) for transformers 0-OXF-228-3, -228-4, -226-A, and -226-B.

[2] If any of the combustible liquid transformers are located in "buffer zones," as described in Part III, Section 10.3.1, provide the technical justification that locating such an ignition source with integral combustibles in that buffer zone would not impact safe shutdown capability.

[3] In addition, update Section 2.4 of Part VII to include combustible liquid filled transformers as an intervening combustible, if these transformers are in areas that have been evaluated for intervening combustibles.

TVA Response:

[1] The transformers 0-OXF-228-3 and 0-OXF-228-4 are located in the Auxiliary Building, el. 692. They are located at the far sides of the el. 692 general area as shown in Figures 1 and 2 (Attachment 3). Transformer 0-OXF-228-3 is in the sub-area 692.0-A1A1 and 0-OXF-228-4 is in the sub-area 692.0-A1B1 as shown on Figure 3 (Attachment 3).

The Transformers 0-OXF-226-A and 0-OXF-226-B are located in the Intake Pumping Station (IPS), Electrical Board Room, el. 711 as shown on Figure 4 (Attachment 3). Transformer 0-OXF-226-A is located in the sub-area IPS-CC-A and 0-OXF-226-B is located in the sub-area IPS-CC-B. Figure 5 (Attachment 3) provides a general electrical component layout sketch of these transformers.

[2] As shown in Figures 1 thru 3, the transformers at Auxiliary Building, el. 692 are not in the "buffer zones" for the analysis and are adequately separated by the buffer zone.

The Electrical Equipment Room in the IPS is located on elevation 711.0 and is of reinforced concrete construction with a minimum thickness of 12 inches. The room has a floor area of 2,608 ft^2 and a nominal ceiling height of 16 ft. The south wall (separates the Electrical Equipment Room from adjacent IPS rooms) is a 3-hour fire rated barrier. The other three walls are below grade, and the ceiling separates the room from the outside. The in situ combustible load in the room results in a fire severity classification of Moderate (<160,000 Btu/ft^2); however, the majority of the combustible load is due to insulation on the cables in trays (83%) and insulating oil in the two transformers (13%). Each transformer is inside a curbed area with a capacity of approximately 370 gallons. The Dow Corning 561 silicone transformer liquid (see Attachment 4 for data from Dow Corning) would either self-extinguish itself or be extinguished by the suppression system provided for the room.

The Electric Equipment Room is provided with detection and automatic suppression. The detection system would detect a postulated fire in its early development and alarms in the MCR would alert staff to the fire. If the fire increased in intensity, the automatic sprinkler system (sprinkler heads are 212^{0}F rated) would operate and extinguish or control the fire until the Fire Brigade responds.

The FSSD requirements for a fire in the IPS are for a minimum of two ERCW pumps to be unaffected by the fire. The electrical power and control cables for the ERCW pumps enter the Electrical Equipment room from the Train A and B conduit duct banks on the west (Train A) side and east (Train B) sides of the room. The cables exit the trays along the south wall and are embedded in the concrete until they exit near each pump. The worst case location of a fire (i.e., one of the transformers) would only impact cables for two of the ERCW pumps. This leaves six of the pumps (minimum FSSD requirement is two pumps) available. Even applying the very conservative requirements of Appendix R, Section III.G.2, the minimum required number of Train A and Train B pumps complies with the acceptable separation requirements of Section III.G.2.b (20 feet with suppression and detection with no continuous intervening combustibles).

[3] Part VII, Section 2.4 will be revised to include the oil filled transformers and will be included in the next FPR submittal.

21. NRC Question (RAI FPR VIII-21.2)

The response to RAI FPR VIII-21 in the August 5, 2011, TVA letter contains the following statement as a basis of acceptability: "Silicone fluid fires are extinguished in 20 to 30 seconds with a water application of 0.15 gpm/sq. ft."

Provide a basis for this statement using technical analysis or test results from an independent testing laboratory, or provide other technical information that supports the statement.

TVA Response:

This information relative to silicone dielectric fluids being extinguished in 20 to 30 seconds with a water application of 0.15 gpm/sq. ft. was provided in the vendor information on this fluid. Please refer to Section 2.5.2, page 2-11 of the attached vendor information (Attachment 4) for the source information on this water extinguishment requirement.

22. NRC Question (RAI FPR VIII-22)

A change was made in Part VIII, element F.12, of the FPR, to delete text in the "Plant Conformance" column that indicated that automatic detection is installed in the fuel receipt area and New Fuel Vault. Additionally, the following was added to the "Alternatives" column: "Detection is not provided in the New Fuel Storage Vault (el. 741.5). Refer to Part VII, Section 4.5 of the FPR."

Part VII, Section 4.5 is an evaluation of the lack of detection in the refueling room (757.0-A13), and does not mention the New Fuel Storage Vault or any other rooms.

[1] *Provide a technical justification for the lack of automatic detection in the New Fuel Storage Vault. One means might be to expand the evaluation in Part VII, Section 4.5, to encompass this area.*

[2] *Is there automatic detection installed in the fuel receipt area? If not, provide a technical justification for the lack of automatic detection in this area.*

This RAI may involve an update to the FPR to incorporate the response to the RAI.

TVA Response:

[1] See Question 15 (RAI FPR VII-21).

[2] In accordance with the WBN Fuel Handling Instruction (FHI), fuel receipt process begins with the arrival of the truck at the WBN site but new fuel receipt is only performed in the Refueling Floor, Rm. 757.0-A13, since in this area is the only room where the new fuel transportation casks are opened. The new fuel transportation casks are designed to protect the fuel from normal over-the-road accidents such as impact and fire. Thus, when the new fuel transportation casks are in their closed shipping configuration, fire is not a concern. The Refueling Floor has been the location where the fuel transportation casks are opened since the first fuel was received at WBN. The justification for no automatic detection for the fuel receipt area was provided as the justification for no automatic detection on the Refueling Floor. The justification for the no automatic detection for the Refueling Floor is provided in the FPR, Part VII, Section 4.5 (see [1] above).

23. NRC Question (RAI FPR II-26.1) (Received in email dated September 20, 2011 from NRC [Justin Poole, NRR])

In the response to RAI FPR II-26 (ML11129A158), TVA noted that the frequency of the GL 82-21 annual fire protection audit has been changed to 24 months and refers to an August 28, 2002 letter (ML022460173) to the NRC documenting this change. TVA states in the August 28, 2002 letter that this change was implemented using a performance-based schedule as allowed by the NRC Regulatory Guide 1.189 (section 1.7.10.1 of revision 0).

Provide more detail regarding this change. In particular,

[1] *A summary of the performance based process used to make the change*
[2] *A summary of how the change is being monitored.*

This summary information would be appropriate to include in the FPR at the correct level of detail.

TVA Response:

[1] A summary of the performance-based process used to make the change:

The change was made using 10 CFR 50.54(a)(3)(i) which allows revision to those Quality Assurance (QA) programs that use a QA standard approved by the NRC which is more recent than the QA standard in the licensee's QA program at the time of the update.

Attachment 5, Fire Protection Program Audit Frequency, list the audits and assessments that have been performed over the past several years to implement this change. This process is described in the Nuclear Quality Assurance Plan (NQAP) (TVA-NQA-PLN89-A), along with the associated supporting Audit and Assessment Procedures.

This change committed TVA through TVA-NQA-PLN89-A to Regulatory Guide 1.189, Revision 0, dated April 2001. Attachment 5, Fire Protection Program Audit Frequency, shows that TVA has been completing off-year performance based assessments in accordance with Regulatory Guide 1.189, Revision 0, dated April 2001, with one exception. The exception occurred between the 2003 and 2005 Audits. During the preparation for the Audit in 2005, the omission was identified. This omission was entered into the corrective action program. Corrective actions included further updating of the NQAP and associated supporting Audit and Assessment Procedures. These actions have been effective in that no recurrences have occurred since that time. Additionally, it can be seen that if QA is not satisfied with a station's performance, that station has been subject to additional auditing (i.e., 2002 at Sequoyah).

Attachment 5 provides detailed review of the Fire Protection Program Audit Frequency and demonstrates that TVA has been satisfactorily meeting the requirements of Regulatory Guide 1.189, Revision 0, dated April 2001.

[2] A summary of how the change is being monitored:

As noted previously, one exception occurred early in the transition to Regulatory Guide 1.189, Revision 0. Corrective actions from that occurrence, along with results from the associated supporting Audit and Assessment Procedures, ensure the commitment was further refined in TVA-NQA-PLN89-A during Revision 14-A2.

The periodic scheduling and performance of audits and assessments monitors the health of the fire protection program, and if QA identifies degradation in the program at a particular site, the audit frequency for that site would be increased. It can be seen in the table that in one case, since this change was implemented, QA was not satisfied with a station's performance and that station has been subject to additional auditing (i.e., 2002 at Sequoyah).

With regard to "This summary information would be appropriate to include in the FPR at the correct level of detail," the following revision to Part II, Section 7.7 will be included in the next FPR:

The Fire Protection Program uses the applicable parts of the TVA Nuclear Quality Assurance Plan (TVA-NQA-PLN89-A) to manage the audit frequencies. This QA program is further described in corporate standards and implementing procedures. Any changes to the NQAP are controlled under 10CFR50.54(a).

24. *NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)*

Part VII, Section 8 - The Section uses the term "Fire Room." This term is not used in other parts of the report. Change the term to simply "Room." This appears in Section 8.3.1, etc. Perform a generic review and correct any changes in to the next FPR submittal.

TVA Response:

A review of Part VII, Section 8 has been performed and the section has been revised to replace "fire room" with "room." The change will be included in the next revision to the FPR.

25. *NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)*

Part VII, Section 8.3.52.2 uses the term "automatic action sprinklers." The proper term is "preaction" sprinklers. Perform a generic review and correct any changes in to the next FPR submittal.

TVA Response:

The term preaction sprinklers is a subset of automatic sprinklers. The term automatic sprinklers is used throughout the FPR. A review has been performed to change automatic action sprinklers to automatic sprinklers. The change will be included in the next revision to the FPR.

26. *NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)*

Part II, B. 14.1.C - Add discussion that each unit's refueling outage is 18 months; therefore, the use of the term "Refueling Outage" gets everything tested in one unit's outage or the other so that everything has a test within it's 18 month frequency.

TVA Response:

TVA agrees the terminology of "Refueling Outage" could result in confusion with two unit operation. To address this issue, the following changes will be included in the next FPR submittal:

Part II, Section B.14.1.c:

TIR 14.1.c is the performance of a functional test on each of the required smoke detection and restorable heat detection instruments which are in any inaccessible area.

This test is performed for the unit in a refueling outage. The expected frequency for this testing is each unit's Refueling Outage and is based on operating experience.

Part II, B.14.3.c:

TIR 14.3.c ensures that each automatic spray/sprinkler system valve actuates to its correct position. These deluge valves for preaction systems have limited means to ensure a cycle of travel is achieved. Industry practice on cycling these valves by closing the isolation valve all but a few turns until the deluge valve opens and then completing the closing of the isolation valve will be used. This TIR also ensures that each testable valve in any inaccessible area will travel through at least one cycle. Any pushbuttons provided at deluge valves for manual start of the fire pumps are not tested as a part of this TIR. These pushbuttons are provided for when the deluge valve is manually activated. Upon discovery of a fire, plant personnel are trained to report all fires before trying to fight them. Additional administrative controls are in place to ensure that a fire pump(s) is running when a fire is reported. A unit's Refueling Outage frequency was developed considering that many surveillances can only be performed during an outage. Standard Technical Specification requirements and operating experience have shown these components routinely pass the TIR when performed on the 18 months/Refueling Outage frequency. Therefore, the frequency was concluded to be acceptable from a reliability standpoint.

Part II, B.14.3.d:

TIR 14.3.d performs a general, floor level visual inspection of each spray or sprinkler system once every 18 months for accessible areas and for the unit in a Refueling Outage for inaccessible areas. This general inspection identifies any abnormal conditions and/or physical damage to the riser, sprinkler piping network, and hangers. This inspection includes assurance that spray/sprinkler head discharge patterns are not obstructed from providing protection from the hazards present. This inspection is not intended to perform a field verification of the design of the installed spray/sprinkler system. The 18 months/Refueling Outage frequencies have been established and are consistent with standard Technical Specification requirements. Design and modification controls exist to prevent improper fire protection system installation or permanent impairment of operation through improper installation of plant equipment.

Part II, B.14.3.e:

TIR 14.3.e verifies during outages that each testable valve in any inaccessible area is visually inspected to be in its correct position. The test is performed during each cold shutdown exceeding 24 hours unless the TIR was performed in the previous 92 days. The verification is to be performed each 92 days during extended outages. The frequency for the TIR is based on the assumption that the required valves cannot be tested until the plant is in cold shutdown for more than 24 hours. Valves that are locked, sealed, or otherwise secured in position need only be verified to be locked,

sealed, etc., since these were verified to be in the correct position before locking, sealing, or securing. A frequency of 92 days during outages has been established and is more conservative than the inspection criteria established for primary system valves that are locked, sealed, etc. The expected frequency for this testing is each unit's Refueling Outage and is based on operating experience.

Part II, B.14.6.e:

TIR 14.6.e ensures that each dry standpipe water flow device actuates to its correct position upon an initiation signal. The dry standpipe control valve is a deluge valve for which there is limited means to ensure a complete cycle of travel is achieved. For cycling these valves, the industry practice of closing the isolation valve all but a few turns until the deluge valve opens and then completing the closing of the isolation valve. Also, each testable valve in any inaccessible area will travel through at least one cycle. The pushbuttons associated with these hose stations in the Reactor Buildings not only provide a means to open the deluge valve that allows water into the normally dry standpipe system as discussed in Section 12.2 but also start the fire pumps. Although these Reactor Building hose stations are manual and plant personnel are trained to report a fire before fighting it, there are no administrative controls to ensure the deluge valve is activated as there are for the start of the electric motor driven fire pump(s). Therefore, these push buttons are tested. Any other pushbuttons provided at hose stations other than the Reactor Buildings for manual start of the fire pumps are not tested as part of this TIR. The 18 month frequency for accessible areas and each unit's Refueling Outage frequency for inaccessible areas was developed considering the scope and requirements of some tests and inspections can only be performed during a unit outage. Operating experience has shown these components routinely pass the TIR when performed on the 18 month/Refueling Outage frequency. Therefore, the frequency was concluded to be acceptable from a reliability standpoint, and is consistent with standard Technical Specification requirements.

Part II, B.14.6.f:

TIR 14.6.f requires performance of a visual inspection of the fire hose stations that are in any inaccessible area to assure all required equipment is at the station and the station is not blocked or obstructed. The Refueling Outage frequency was developed considering that many tests and inspections can only be performed during a unit outage. Operating experience has shown these components routinely pass the TIR when performed on each unit's Refueling Outage frequency. Therefore, the frequency was concluded to be acceptable from a reliability standpoint, and is consistent with standard Technical Specification requirements.

Part II, B.14.8.d:

TIR 14.8.d requires each unit's Refueling Outage frequency visual inspection of approximately 33-1/3 percent of the surface area of fire rated assemblies/fire barriers to

determine Operability. Inspection of bellows, metal plates, ERFBSs, radiant energy shields, or insulation covering a penetration seal, provides verification of the fire rated assembly/fire barrier integrity, provided there is no apparent change in appearance or abnormal degradation. Inspections validate their functional integrity and ensure that fires will be confined or adequately retarded from spreading to adjacent portions of the facility.

Part II, B.14.9.c:

TIR 14.9.c requires that the EBL in inaccessible areas inside the Unit 1 and 2 Annulus be replaced each refueling outage for that unit and that the tests and inspection described under bases 14.9.a be performed to ensure EBL operability. This is being done due to the ALARA considerations in the Reactor Building and the limited accessibility during plant operation. The surveillance frequency and battery replacement are considered conservative and reasonable based on the fact that these are 15 year service life batteries that are being replaced on a refueling outage frequency.

27. NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)

Part II, B. 14.3.1.a - The sentence reads wrong. There are too may "detection inoperable" words.

TVA Response:

This section was in the as-designed FPR sent to NRC on August 15, 2011, and incorrectly added one "detection" too many. The FPR, Part II, Section B.14.3.1.a will be revised as follows and will be submitted in the next FPR:

> When detection or both suppression and the associated detection are inoperable in an area, then the more stringent compensatory actions are needed. If only the water based suppression is inoperable, then the early warning detection system will provide more extensive coverage of the area and faster notification than can be provided by a fire watch. Therefore, it is appropriate to provide a lesser degree of fire watch coverage (i.e., Hourly roving fire watch). When the detection is inoperable and the associated suppression is still operable then the more restrictive compensatory action is required. In this situation, not only is the early warning capability lost, but so is the automatic actuation capability of the suppression system.

28. NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)

Part II, Page II-128 for the floor elevations for zone 331 versus zone 330. They should be the same.

TVA Response:

TVA agrees the as-designed FPR sent on August 15, 2011, incorrectly lists these elevations as different. The elevations for the Pipe Chase, Unit 1 and Unit 2 should be the same and they should be Elevation 676, Elevation 692, and Elevation 713. The FPR, Part II will be revised to correct the elevations for Zone 331 on page II-128, and this revision will be submitted in the next FPR.

29. *NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)*

In the August 5, 2011 submittal, Question VI-7.1, TVA provided clarifying information for the Unit 2 Reactor Building compartmentation. TVA needs to fix the description of the Unit 1 Reactor Building in the FPR.

TVA Response:

TVA will update the description of the Unit 1 Reactor Building in the next FPR submittal.

30. *NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)*

Part VII, Section 3.1.1 - In room 674.0-A1, Waste Holdup - Clarify what is meant by "required for auxiliary control?"

TVA Response:

Cables that are only required for a fire in the Auxiliary Control Room are called auxiliary control circuits. The circuits in room 674.0-A1 are auxiliary control circuits and are not required for a fire in this room.

31. *NRC Question VII-26 (Received in email dated September 20, 2011 from NRC [Justin Poole [NRR])*

The text of Part VII, Section 2.4, "Intervening Combustibles," indicates that this deviation is for the Auxiliary building. However, the reviewers have identified two instances of reliance on this deviation for areas outside of the Auxiliary Building.

[1] Table I-1 lists Deviation 2.4 for Fire Area 53, Diesel Generator building (page I-12) and fire Area 60, IPS

[2] These are also reflected in Part 3.59 (Diesel generator Building) and Section 3.66, (iPS). Section 3.59 was revised to include crediting the deviation for the 8/15/11 version of the FPR.

The deviation should be revised to reflect all of the areas that it is relied upon.

TVA Response:

[1] The Diesel Generator Building is not part of Deviation 2.4. Table I-1 will be revised to delete this reference in the next FPR submittal. The IPS does rely on this deviation and is addressed in previous question VII-21.1.

[2] Part VI, Section 3.59 will be revised to delete the reference to Part VII, Section 2.4 and will be included in the next FPR submittal.

The deviation in Part VII, Section 2.4 will be revised to address the IPS and will be included in the next FPR submittal (see question VII-21.1).

32. NRC Question II-48 (Received in email dated September 20, 2011 from NRC [Justin Poole, NRR])

[1] The information used to create the SSER 18 section 3.1.4.2 "Internal conduit Fire Barrier Penetration Seals" currently exists only in an RAI response from July 1, 1994 (ML072320559) and not in the FPR. In order to achieve a cleaner licensing basis, it would be appropriate to include this information in the FPR.

[2] Additionally, there is a conflict regarding the combustibility of the seal material between the RAI response and the internal conduit seal definition in Part II of the FPR.

TVA Response:

[1] The following information from the July 1, 1994 RAI response describing the requirements for internal conduit seals will be added to Part II, Section 12.10.6.B in the next revision of the FPR:

> A 1-hour, 2-hour, or 3-hour rating in accordance with IEEE 634-1978, section 6.1 was established for electrical penetration seals. Transmission of heat through the penetration seal was limited to 700° F or the lowest auto-ignition temperature of cable in the penetration, whichever is lower.
>
> Conduit penetrations typically require only internal seals since most conduit penetrations were poured-in-place during plant construction. Internal seal materials, design, and locations in walls and floor/ceiling assemblies have been evaluated as equivalent to tested configurations. If a conduit requires an external seal (e.g., the conduit passed through a sleeve larger than the conduit), the external seal will meet the same criteria as stated in the above paragraph.
> The criteria for internal conduit seals that were reviewed and approved by the NRC are based on the information presented in an RAI response from July 1, 1994 (ML072320559). The following information is from that submittal.

The internal conduit seal criteria is documented on drawing series 45W883 and is as follows.

Smoke and gas seals shall have a (min) 3 inch RTV silicone foam and 1 inch ceramic fiber damming at the bottom/back side of the foam. The fiber damming may or may not exist in the front/top side of the foam. The silicone foam shall be installed at the first available opening. Conduits that terminate in junction boxes or other non-combustible enclosures need not additional sealing except for Auxiliary Building secondary containment envelope boundaries. See table below for sealing instructions. A closed electrical cubical similar to a motor control center or switchgear cabinet is not considered a non-combustible enclosure.

CONDUIT	TOTAL LENGTH OF CONDUIT FROM BARRIER					
SIZE	CONTINUOUS THRU AREA	<1'	≥1' - <3'	≥3' - <5'	≥5' - <22'	≥22'
<1"	NSR	F	NSR	NSR	NSR	NSR
1"	NSR	F	S	S	NSR	NSR
>1" - <2"	NSR	F	S	S	NSR	NSR
2"	NSR	F	F	S[4]	NSR	NSR
>2" - ≤4"	NSR	F	F	F[4]	S[4]	NSR
>4"	NSR	F	F	F	S	NSR

Notes:
1. NSR – No Seal Required
2. S – Smoke and Hot Gas Seal Required
3. F – Fire Seal Required
4. NSR if cable fill exceeds 40%

[2] The definition of Internal Conduit Seals, Smoke and Hot Gas Seals in Part II, Section 5.0, will be revised to delete the reference to non-combustible material and will be included in the next FPR submittal. The new definition is as follows:

"Smoke and Hot Gas Seals – Seals installed inside conduit openings to prevent the passage of smoke and hot gasses through fire barriers. These seals may be located at the fire barrier or at the nearest conduit entry on both sides of the fire barrier. Smoke and hot gas seals are not required to have a fire resistance rating equal to the fire barrier in which they are installed."

Enclosure 2

Summary Listing of Fire Protection Commitments

1. The corrections identified in Letter Item # *1 (NRC Question RAI FPR General-7),* subsection [1] will be submitted in the next FPR.

2. A review of the FPR has been performed to identify and correct similar deficiencies that occurred when modifying the FPR to align with past RAI responses. The deficiencies that were identified during this review will be submitted in the next FPR. A summary table of the identified deficiencies is included in Attachment 1. [Letter Item # 1. NRC Question (RAI FPR General-7) subsection [2]]

3. The corrections identified in the FPR Part VI, Section 3.26.1, subsection [1] and Part I, Table I-1, subsection [2] will be submitted in the next FPR. [Letter Item # 2. NRC Question (RAI FPR General-8) subsection [1] and [2]]

4. FPR, Part I, Table I-1 will be corrected to reflect that no OMAs or repairs are required for a fire in rooms 713.0-A10, 713.0-A17 and 737.0-A10 and will be submitted in the next FPR submittal. [Letter Item # 3. NRC Question (RAI FPR I-3) subsection [1]]

5. A review of the FPR has been conducted for consistency between sections. Identified discrepancies have been corrected and will be included in the next FPR submittal. [Letter Item #s 1,2 & 3]

6. FPR, Part II, Section 14.1.2.b will be revised to specify that the section applies only to inaccessible areas outside of containment, as defined by the FPR, Part II, Section 5.0. [Letter Item # 4. NRC Question (RAI FPR II-37.1.1)]

7. The changes contained in Letter item # 7 [NRC Question (RAI FPR II-46)] will be submitted in the next FPR.

8. The changes contained in Letter item # 8 [NRC Question (RAI FPR II-47)] will be submitted in the next FPR.

9. Part V, Section 2.2.2 of the FPR will be submitted in the next FPR submittal. [Letter item # 9. NRC Question (RAI FPR V-13.1)]

10. The fire detection system provided for 692.0-A1B does not extend into the tunnel. Section 8.3.3.2 will be revised to clarify that the tunnel from 692.0-A1B is not provided with detection or automatic suppression. This change will be submitted in the next revision to the FPR. [Letter item # 12. NRC Question (RAI FPR VII-18)]

11. The revisions to the FPR that were discussed in Letter Item # 13 [NRC Question (RAI FPR VII-19)] will be added as parts of new Section 3.1 in the next FPR submittal. In addition, an extent of condition review has been performed for this item, and the results will be included in the next revision of the FPR.

12. The changes contained in Letter item # 14 [NRC Question (RAI FPR VII-20)] will be submitted in the next FPR.

13. The Engineering Evaluation documented in Part VII, Section 4.5 will be revised to provide additional justification for the lack of detection in the Refueling Room and New Fuel Storage Vault and this will also eliminate the need for the OMAs. Therefore, Part VII, Section 8.3.44 is being deleted. These changes to the FPR will be included in the next FPR submittal. [Letter item # 15. NRC Question (RAI FPR VII-21)]

14. TVA confirms there will be procedures for each affected room that address each OMA. The OMAs identified in the FPR are to be verified by walkdowns and documented in AOI 30.2 prior to fuel load. The statement that a room does not have dedicated procedures for fire safe shutdown will be deleted for the evaluations. These revised evaluations will be included in the next FPR submittal. [Letter item # 16. NRC Question (RAI FPR VII-22)]

15. Engineering Evaluations will be performed for the four fire zones (2RA2 - Accumulator Room 2, 2RF2 - Fan Room 2, 2RIR - Instrument Room and 2RO-N - Outside Crane Wall [North]) identified in NRC's request and will be added to Part VII, Section 3.1 of the FPR. These evaluations will be included in the next FPR submittal. [Letter item # 17. NRC Question (RAI FPR VII-23)]

16. TVA has performed a generic review for Unit 2 and identified all rooms in the Unit 2 Reactor Building without detection, but contains FSSD components. Additional information will be added to the next revision to the FPR to address these rooms. [Letter item # 17. NRC Question (RAI FPR VII-23)]

17. The changes addressed in Letter item # 18 [NRC Question (RAI FPR VII-24)] will be in the next FPR submittal.

18. The changes addressed in Letter item # 19 [NRC Question (RAI FPR VII-25)] will be submitted in the next FPR.

19. Part VII, Section 2.4 will be revised to include the oil filled transformers and will be included in the next FPR submittal. [Letter item # 20. NRC Question (RAI FPR VIII-21.1)]

20. With regard to "This summary information would be appropriate to include in the FPR at the correct level of detail," the following revision to Part II, Section 7.7 will be included in the next FPR:

    The Fire Protection Program, uses the applicable parts of the TVA Nuclear Quality Assurance Plan (TVA-NQA-PLN89-A) to manage the audit frequencies. This QA program is further described in corporate standards and implementing procedures. Any changes to the NQAP are controlled under 10CFR50.54(a). [Letter Item #23, NRC Question (RAI FPR II-26.1)]

21. A review of Part VII, section 8 has been performed and the section has been revised to replace "fire room" with "room." The change will be included in the next revision to the FPR. [Letter item # 24. NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)]

Summary Listing of Fire Protection Commitments

22. A review has been performed to change automatic action sprinklers to automatic sprinklers. The change will be included in the next revision to the FPR. [Letter item # 25. NRC Question (Received during August 31, 2011 meeting in Rockville, Md.)]

23. The changes addressed in Letter item # 26 [NRC Question (received during August 31, 2011 meeting in Rockville, Md.)] will be submitted in the next FPR.

24. The FPR, Part II, Section B.14.3.1.a will be revised and submitted in the next FPR submittal. [Letter item # 27. NRC Question (received during August 31, 2011 meeting in Rockville, Md.)]

25. The FPR, Part II will be revised to correct the elevations for Zone 331 on page II-128 and this revision will be included in the next FPR submittal. [Letter item # 28. NRC Question (received during August 31, 2011 meeting in Rockville, Md.)]

26. TVA will update the description of the Unit 1 Reactor Building it will be in the next FPR submittal. [Letter item # 29. NRC Question (received during August 31, 2011 meeting in Rockville, Md.)]

27. The changes addressed in Letter item # 31 [NRC Question VII-26 (received during September 20, 2011 NRC email)] will be submitted in the next FPR.

28. The information from the July 1, 1994 RAI response describing the requirements for internal conduit seals will be added to Part II, Section 12.10.6.B in the next revision of the FPR. [Letter item # 32. [NRC Question II-48 (received during September 20, 2011 NRC email)]

29. The definition of Internal Conduit Seals, Smoke and Hot Gas Seals in Part II, Section 5.0, will be revised to delete the reference to non-combustible material and will be included in the next FPR submittal. [Letter item # 32. [NRC Question II-48 (received during September 20, 2011 NRC email)]

ATTACHMENT 1

Incorporation of RAI Responses into FPR
Results of Review

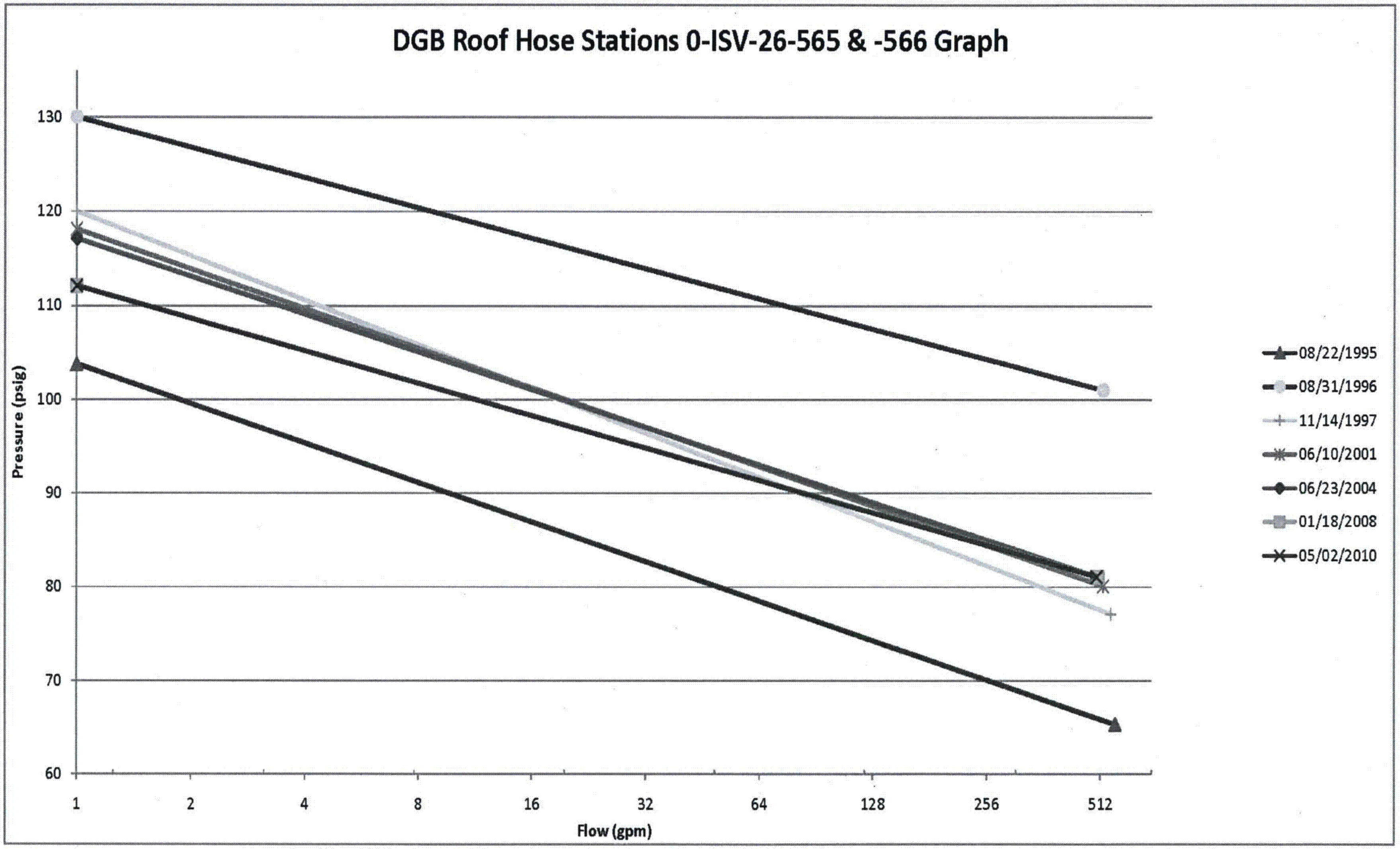
RAI Group	Letter date	RAI ID	FPR (Y/N)	Section Revised	Add Section to Be Revised	COMMENTS
2	03/16/11	V-4	Y	V-2.4.2	V-2.4.2 Remove "or less"	Part V, section 2.1.2.2.d talks about "OMAs to be performed in the fire affected room in about an hour OR LESS are..." This is consistent with the reviewers concern about "Less than 2 hours."
2	03/16/11	V-6	Y	V-2.4.3, Table I-1	VII-7.1.3, 7.2.1, 7.2.2	Update these sections to agree with the current OMAs.
2	03/16/11	V-9	Y	V-2.4.3, Table I-1	VII-7.2.1	Text in V-2.4.3 deleted by later revision - content pertaining to combustible loading for 729-A10 that was to have been deleted is now in part VII-7.2.1. See V-6 above. Sections 7.1.3.1, 7.2.1, and 7.2.2 will be reconciled to agree the the current OMA set.
2	03/16/11	II-8	Y	II-13.0, 14.1, B.14.1, B.14.2, B.14.3, B.14.4, B.14.8	See response to Group 7 Question 1 FPR-General-7	
2	03/16/11	VII-1	Y	VI-3.15.3	VI-3.15.3	VI-3.15.3 now contains the statement "This eliminates the need for Deviation 4.7 in Part VII." but the change removed Deviation 4.7 so there is no longer a para. 4.7. 3.15.3 should say there is no need for a deviation.

RAI Group	Letter date	RAI ID	FPR (Y/N)	Section Revised	Add Section to Be Revised	COMMENTS
2	03/16/11	VIII-1	N		III-10.3.1.e(3) VII - 2.6.3	III-10.3.1.e(3) should be revised to clarify some new cables may not be qualified to IEEE-383. Also VII - 2.6.3 should be clarified as not all non IEEE-383 qualified are coated with a fire retardant material, i.e., 9 or less in a tray is allowed.
3	05/06/11	II-13	Y	Part II, Section 14.3.1.b.1; Table 14.3; Part III, Section 4.7; Part IV, Section 3.3	See response to Group 7 Question 1 FPR-General-7	Part III, Section 4.7 still says, "Unit 1" and was not revised to include both units. Remainder incorporated.
3	05/06/11	III-13	Y	Part III, Section 4.7; Part II, Table 14.3, item 14.3.c; Part IV, Section3.3; Part II, Section 14.3.1.b.1	See response to Group 7 Question 1 FPR-General-7	Part III, Section 4.7 still says, "Unit 1" and was not revised to include both units. Remainder incorporated.
3	05/06/11	IV-3	Y	Part III, Section 4.7; Table 14.3, item 14.3.c; Part IV, Section3.3; Part II, Section 14.3.1.b.1	See response to Group 7 Question 1 FPR-General-7	Part III, Section 4.7 still says, "Unit 1" and was not revised to include both units. Remainder incorporated.

RAI Group	Letter date	RAI ID	FPR (Y/N)	Section Revised	Add Section to Be Revised	COMMENTS
4	05/26/11	VII-2 (3)	Y	VIII-3.3	VII page 33	The RAI indicated SR 375516 was initiated to correct Part VIII, Sect. 3.3 to state there are three rather than four standpipe systems. The response should have said Part VII, Section 3.3. This correction will be in the next FPR submittal.
4	05/26/11	VIII-3	Y	B.1	X-3.1.2	Title of NFPA-4A was inadvertently changed from ". . .Fire Department" to ". . Fire Brigade." This was correct in the May 2011 FPR submittal. The title of NFPA-4A in Part X, Section 3.1.2 will also be corrected in the next FPR submittal.
4	05/26/11	VIII-7	Y	D.5 "Guidelines"	D.5 "Guidelines"	We changed "communications" to "communication" in 5/18/11 submittal. Typist added "s" back in 8/15/11 FPR submittal. The "s" will be deleted in the next FPR submittal.
6	08/05/11	II-37.1	Y	14.1.1, 14.1.2, B14.1.1, B14.1.2	See response to Group 7 RAI-II-37.1.1 follow up question	
6	08/05/11	III-15	Y	4.2.66	4.2 (add WBPEVAR9205004, EPM-BFS-041895, EPM-BFS-053195, EPM-BFS-063095)	looked for calcs referred to in text but not referenced in section 4; found 4.
6	08/05/11	VI-7.1	Y	table 3.3 VI 3.84.3.2 thru 3.84.3.12	3.67.3.2 thru 3.67.3.12	Make same changes for Unit 1 reactor building AV-092
6	08/05/11	VI-9	Y	AV-091 & AV-117	II-4.2	Add calculation WBPEVAR9602001 to references in Part II,

RAI Group	Letter date	RAI ID	FPR (Y/N)	Section Revised	Add Section to Be Revised	COMMENTS
						section 4.2
6	08/05/11	VI-10	Y	AV-092A-L & AV-118A-L	II-4.2	Add calculation edq00099920110005 to references in Part II, section 4.2

ATTACHMENT 2



Attachment 3 Redacted

ATTACHMENT 4

Dow Corning 561 Silicone Transformer Liquid Training Manual

Dow Corning® 561 Silicone Transformer Liquid

Technical Manual

Preface

We hope this technical manual will help you discover for yourself the advantages of using a transformer filled with ***Dow Corning®*** 561 Silicone Transformer Liquid. The information on proven performance, fire safety, human and environmental safety, recyclability, and cost effectiveness all indicate that ***Dow Corning®*** 561 Silicone Transformer Liquid offers significant benefits over other types of liquid-filled and dry-type transformers.

Dow Corning® 561 Silicone Transformer Liquid is backed by Dow Corning Corporation, which has a team of technical specialists around the world specifically committed to ***Dow Corning®*** 561 Silicone Transformer Liquid. That means if you ever have a question or a problem, you'll always get an answer—and a solution.

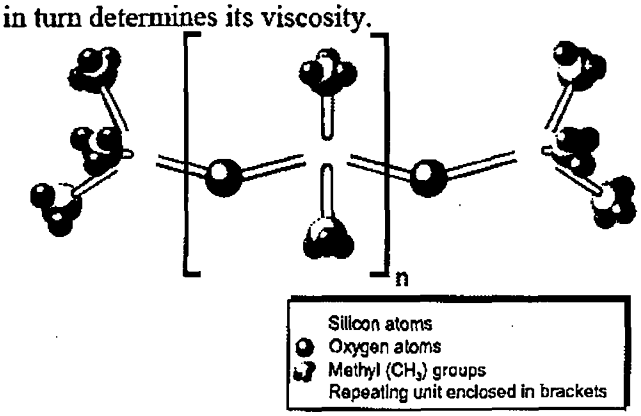
Table of Contents

Section 1: General Information

Section Content

1.1 What Is a Silicone Fluid?

Silicone fluids are a family of synthetic liquids having the molecular structure shown below, in which the groups identified as methyl groups may represent any organic group. The organic groups can be all the same or different. The value of n determines the molecular weight of the silicone fluid, which in turn determines its viscosity.



Polydimethylsiloxane (PDMS) fluids are thermally stable, chemically inert, essentially nontoxic, and water repellent. The viscosity of the commercial products varies from 0.65 to 2,500,000 centistokes (cSt). These fluids remain fluid over a wide range of temperatures, even though the value of **n** can vary from 0 to 2,000 or more. Other physical and electrical properties exhibit relatively small variations with temperature.

Silicone fluids are used as lubricants, mold-release agents, dielectric coolants, antifoam agents, and heat-transfer fluids. Because of their unique surface properties, low toxicity, and thermal and chemical stability, they are used in small concentrations in car polishes, paints, and cosmetics.

Dow Corning® 561 Silicone Transformer Liquid is a 50 centistoke viscosity PDMS product, in which all the organic groups are methyl groups, CH_3. It is water-clear, nongreasy, and virtually odorless, with good insulating and dielectric properties.

1.2 Selecting a New Transformer

Selecting the best transformer for a given application might seem like a difficult task, but with the right information—backed by proven applications and 20 years of testing—a difficult decision can be made easy.

There is a variety of transformer types from which to choose, including air-cooled dry-type, cast-resin, and liquid-filled transformers. Liquid-filled transformers can contain mineral oil, chlorinated hydrocarbons, high molecular weight hydrocarbons, or silicone fluid. Depending on the needs of your application, each type offers distinct advantages. But many also have drawbacks. The key is to decide which engineering and operating compromises are acceptable and estimate the long-term effects they will have on your application.

We believe the information in the following pages will help you select which type of transformer will work best for you and which should be avoided for your application.

1.3 Why a Liquid-Filled Transformer?

Liquid-filled transformers were developed more than 90 years ago. Today, many users continue to prefer this design over dry-type transformers, especially for demanding applications such as networks and medium and large power transformers. There are several important reasons for this preference.

- Unlike solids, liquids cool as well as insulate. As a result, you can select a liquid-filled transformer that is more compact than a comparable dry-type or cast-resin type.
- Liquid-filled transformers provide high efficiency and high BIL at reasonable cost. Similar electrical performance can be obtained from dry-type or cast-resin transformers—but usually only at additional cost.

Performance Without Extra Cost

The high dielectric strength of liquid-filled transformers provides greater design flexibility. As a result you can optimize the design to meet specific load requirements and thereby reduce operating costs. For example, beginning with a liquid-filled system, you can design a small, compact core transformer that delivers a very high BIL and very low no-load losses. You can

achieve a combination of operating economy, reliability, and small size that is not practical with dry-type and cast-resin transformers. Table 1-1 compares the BIL rating of dry-type transformers to liquid-filled transformers.

Table 1-1. Typical temperature rise and BIL ratings for transformers

Transformer type	Average winding temperature rise	BIL rating
Liquid filled	55/65°C	95 kV
Dry	150°C	60 kV

Liquid systems also have an advantage stemming from their superior ability to remove heat from the core and coil assembly. This results in greater overload capacity and corresponding savings in maintenance and operating costs, as well as longer insulation life. This is especially true for silicone-filled transformers because silicones have the highest thermal stability of all available liquids. Long-term costs resulting from energy loss in a unit can exceed the capital costs of purchasing the transformer. As a result, it is very important to evaluate the rate of loss and select the best design for your load and service conditions.

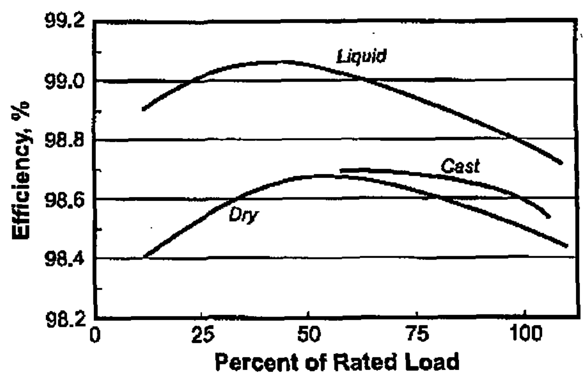


Figure 1-1. Typical efficiency for major types of transformers

To provide for load growth or emergency loading, transformers are usually designed to handle more than the expected initial load. A loss evaluation is based on average transformer loading. Figure 1-1 shows that liquid-filled transformers are more efficient, particularly at low load levels.

Size and Weight

Table 1-2 shows a dimension and weight comparison of liquid-filled, dry-type, and cast-coil transformers with different temperature rises.

Table 1-2. Dimensions and weights of 1000 kVA, 13.8 kV - 480 V transformer[a]

	Liquid-filled	Conventional dry type		Cast coil
Temperature rise	65°C	150°C	80°C	80°C
Height	65.0 in.	90.0 in.	100.0 in.	90.0 in.
Width	58.5 in.	78.0 in.	84.0 in.	84.0 in.
Depth	74.5 in.[b]	58.0 in.	70.0 in.	54.0 in.
Total weight	6980 lb	5830 lb	8500 lb	7500 lb

[a] References from transformer manufacturer's data

[b] Includes depth of radiators

Quiet

Whether indoors or near buildings and people, loud or overbearing noise can be an environmental nuisance. Dry-type transformers, in general, aren't known to be quiet. Liquid-filled transformers, because of their insulation, are the quietest transformers available. Figure 1-2 shows maximum average sound levels.

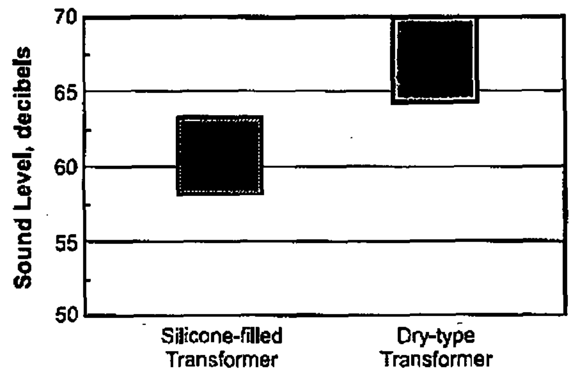


Figure 1-2. Maximum average sound levels for three-phase, substation-type transformers

Predictable Performance

One reason liquid-filled transformers are more reliable than dry types is because they can be diagnostically tested, providing important predictive information to transformer owners. Periodic testing of water content, breakdown strength, and dissolved gas composition can help avoid costly, unplanned outages and catastrophic failures by detecting leaks, low-level arcing, and other insulation problems before they develop into serious situations. See Section 6.1 for details on diagnostic tests for silicone-filled transformers.

Liquids don't crack or form voids under extreme temperature variations, so you can expect long service life. Plus, liquid-filled transformers are sealed so they can operate in many harsh environments without special housings. They also reduce maintenance costs by eliminating the need for and inconvenience of annual shutdowns for cleaning. All in all, liquid-filled transformers are reliable and efficient suppliers of modern power requirements.

1.4 Why a Silicone Liquid?

Most liquid-filled transformers are filled with mineral oil. The primary drawback of mineral oil is that it can present an unacceptable fire risk when used in or near buildings. With silicone fluid, you can meet code requirements without the expense of special vaults and/or fire protection. You gain the reliability and efficiency of liquid-filled design even when the transformer must be located close to the load, indoors, or near buildings. See Section 4.2 for details on code requirements.

Dow Corning began investigating silicone fluids as potential dielectric coolants in the 1950s. The investigation resulted in the development and production of ***Dow Corning***® 561 Silicone Transformer Liquid, which is now widely used to provide excellent performance in liquid-filled transformers, especially where fire safety and thermal stability are required.

A Pure Synthetic Material

Dow Corning® 561 Silicone Transformer Liquid contains no chlorine or other halogens. It is a pure polydimethylsiloxane material that contains no additives, such as pour-point depressants or thermal stabilizers. Similar silicone fluids are used in cosmetics and as food additives. It is compatible with materials used in the construction of transformers, nonvolatile, thermally stable, and chemically inert. This compatibility and stability are instrumental in prolonging transformer life and reducing maintenance.

Fire Safety Indoors or Outside

Dow Corning® 561 Silicone Transformer Liquid presents a much lower fire hazard than other transformer fluids. It is difficult to ignite, but if it should ignite, it produces less heat and smoke and virtually extinguishes itself when the external source of heat is removed. ***Dow Corning***® 561 Silicone Transformer Liquid is Underwriters Laboratories, Inc. (UL) classified and Factory Mutual Research Corporation (FM) approved as "less flammable" per NEC 450-23. In addition, tests have shown that the toxicity of combustion byproducts from ***Dow Corning***® 561 Silicone Transformer Liquid is lower than other commonly used insulating materials, such as high molecular weight hydrocarbons or mineral oil, as well as epoxies, phenolics, polyesters, and other dielectric materials used for transformer construction. See Section 2.5 for details on fire safety.

Stability Leads to Long Life and Lasting Performance

The thermal stability of silicone also improves performance while reducing the need for fluid reprocessing during use. ***Dow Corning***® 561 Silicone Transformer Liquid will not form sludge and/or acidic byproducts, even at elevated operating temperatures. See section 3.2 for details on the thermal capabilities of silicone fluid. Figures 1-4 and 1-5 show how dissipation factor and dielectric strength change as common transformer fluids age at elevated temperatures.

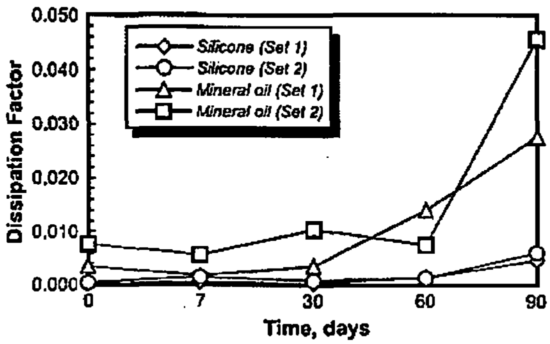


Figure 1-4. Change in dissipation factor of silicone fluid with aging compared to mineral oil.

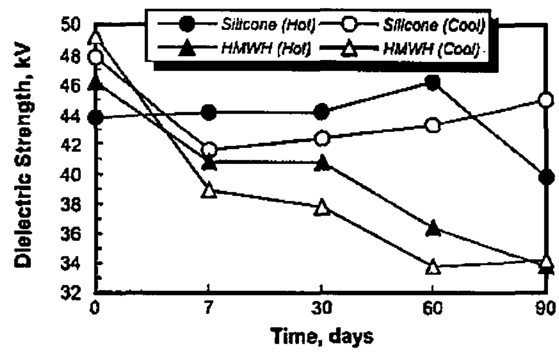


Figure 1-5. Change in dielectric strength of silicone fluid with aging compared to high molecular weight hydrocarbons

Widespread Acceptance

Since 1974, ***Dow Corning***® 561 Silicone Transformer Liquid has been accepted by utilities and commercial property owners as well as industries ranging from food processing and pharmaceuticals to mining, paper mills, and transportation. In fact, a survey of utilities (Figure 1-4) found that when askarel-filled transformers are replaced, nearly 91% of those units are being replaced with silicone-filled units, compared to 8.6% for R-Temp* fluid and 0.3% for dry-type transformers.

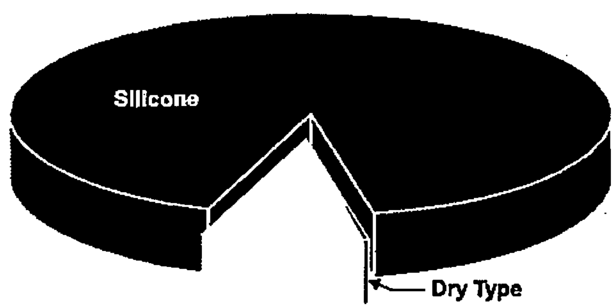


Figure 1-6. Askarel fire-safe transformer replacement choices (Source: 1987 utility analysis follow-up survey where fire-safe transformers were used.)

With over 100,000 silicone-filled units in operation worldwide and more than 20 years of practical operating experience, Dow Corning is not aware of any transformer filled with ***Dow Corning***® 561 Silicone Transformer Liquid that has failed to carry the load required for satisfactory performance.

In short, ***Dow Corning***® 561 Silicone Transformer Liquid has performed as expected—no problems caused by the liquid have ever been reported. In fact, even in rare cases where severe failure of protective devices has exposed the fluid to prolonged arcing and ignited the fluid, no thermal damage due to the fluid burning has occurred.

*R-Temp is a registered trademark of Cooper Power Systems, Inc.

1.5 Bibliographic Resources

Dow Corning Corporation has prepared a number of informational brochures, booklets, and technical articles to help you use ***Dow Corning®*** 561 Silicone Transformer Liquid safely and efficiently. Following is a list of these resources, many of which can be ordered by contacting your Dow Corning representative. Others resources mentioned can be obtained directly from IEEE, ASTM or listing agencies such as Factory Mutual or Underwriters Laboratories.

How To Use These Bibliographic Resources

We believe the technical information contained in these reports is accurate even though specific references may be to codes and standards or regulatory requirements that have changed since the time of writing. Information on current requirements relative to transformer fluid is available from Dow Corning. Please contact your local Dow Corning representative or call 1-800-HELP-561 (in the USA) if needed.

General Properties

G1. "Dielectric Properties of Silicone Fluids," Hakim, R.M., IEEE Conference, Paper #C74-262-2. Lit. no. 10-255

G2. "Structure Property Relationships in Silicone Fluid Dielectrics," G. Vincent, G. Fearon, T. Orbeck, Annual Report, Conference on Electric Insulation and Dielectric Phenomena, 1972, pp. 14–22, CA 79 (8), 43156d. Lit. no. 10-256

G3. "Environmentally Acceptable Insulating Fluids May Replace Askarel," D. Duckett, RTE Corp., General Meeting of Transmission and Distribution Committee, Edison Electric Institute, May 8, 1975

G4. "Small Power Transformer Alternatives," S. Mort and W.H. Bishop, Canadian Electricity Forum, April 1992. Lit. no. 10-519A

G5. "A Comparison of Non-liquid Power Transformers with Silicone-filled Units," J. Goudie, Dow Corning. Lit. no. 10-512

G6. "Silicone Materials for Electrical Insulation that Yield Low Heat Release Rates and Low Levels of Toxic Products During a Fire," E.A Reynaert, and W.C. Page, Environmentally Friendly Fire Retardant Systems Conference, Sept. 22–23, 1992. Lit. no. 10-534

G7. "Silicone As a PCB Replacement Fluid," J. Goudie, Dow Corning Corp., 5th Annual Industry & PCBs Forum, Canadian Electricity Forum, Vancouver, B.C., June 1991

G8. *Dow Corning Dielectric Liquids for Power Transformers*

G9. Dielectric Properties of Dow Corning Silicone Fluids, Lit. no. 22-328

G10. "Less Flammable Transformer Liquids Gain Acceptance," *CEE News*, February 1993. Lit. no. 10-544

G11. "Performance Testing of Silicone Transformer Coolant Using 25 kVA Distribution Transformers: Test Facility," D.F. Christianson and F.C. Dall, Dow Corning Corp.

Performance and Service Life

P1. "Performance and Safety Capabilities of Silicone Liquids As Insulating Liquids for HV Transformers," W. Page and T. Orbeck, IEEE, 24th Annual Petroleum & Chemical Industry Conference. Dallas, Texas, Sept. 12–14, 1977. Lit. no. 10-257

P2. "Service Experience and Safety with Silicone Liquid-Filled Small Power Transformers," K. Evans and T. Orbeck, 1984 Doble Engineering Client Conference, April 13, 1984. Lit. no. 10-259

P3. "Silicone Transformer Liquid: Use Maintenance/Safety," R. Miller, *IEEE Trans. of Ind. Appl.*, Vol. 1A-17, No. 5, September/October 1981, Paper IPSD 79-54. Lit. no. 10-208

P4. "Evaluation of the Long Term Thermal Capability of High Temp. Insulating System Using Silicone Liquid as a Dielectric Coolant," L. Gifford and T. Orbeck, *IEEE Trans. of Ind. Appl.*, Vol. IA-20, No. 2, March/April 1984, Paper PID 83-34. Lit. no. 10-253

P5. "Liquid Filled Transformers Having Temperature Operating Capabilities," D. Voytik, IEEE, 1981, Ch1717-8/81/0000-0203. Lit. no. 10-260

P6. "Secondary Substation Transformer Selection Critical to Total System Planning," C.C. Rutledge, *Industrial Power Systems*, June 1984

P7. "Load Break Switching in Silicone Transformer Fluid," S. Mort, J. Goudie, D. Ristuccia, Electrical Manufacturing Technologies Expo, October 1993. Lit. no. 10-578

P8. "Test Results Confirm the Ability of the LBOR II Switch to Operate Properly in 561® Silicone Liquid from Dow Corning," ABB Load Break Switch Test Confirmation, June 8, 1992

P9. "High Temperature Operating Capabilities of Silicone Transformer Fluid," G. Toskey, Electrical Manufacturing Technologies Expo, October 1993. Lit. no. 10-577

P10. "Interpretation of Dissolved Gases in Silicone Transformer Fluids," Lit. no. 10-593.

P11. "Silicone Materials in New High Temperature Liquid Transformer Designs," J. Goudie, Proceedings of the Electrical/Electronics Insulation Conference, IEEE, September 1997

Fire Safety

F1. "Classification and Application of PCB Alternative Fluids, Confusion or Progress?" K. Linsley and T. Orbeck. Doble Conference, April 1985. Lit. no. 10-254

F2. "Fact-finding Report on Flammability of Less Flammable Liquid Transformer Fluids," Underwriters Laboratories Inc., December 16, 1987

F3. "Study of Explosion and Fire Hazards of Silicone Liquid Under Arc Conditions," H. Kuwahara, *et al.*, IEEE International Symposium on Electrical Insulation, Montreal, Canada, June 1976, Paper No. E-7. Lit. no. 10-245

F4. "Fire in a Cast Resin Transformer," K. Herberich, January 1979, *Brandschutz/Deutsche Feverwehr Zeiting*. Lit. no. 10-265

F5. "Silicone Liquids in Transformers," R. Miller. *Electrical Energy Management*, May 1980. Lit. no. 22-779

F6. "Silicone Transformer in a Fire Situation," J. Dimbock, *Electrotechnische Zeitschrift* (ETZ), Vol. 16, July/August 1984. Lit. no. 10-266

*F7. Transformer Fluids, Factory Mutual Approval Guide 1993

*F8. Transformers, Factory Mutual Engineering Corp. Loss Prevention Data Sheet 5-4, 14-8, September 1986

F9. "Characterization of Transformer Fluid Pool Fires by Heat Release Rate Calorimetry," M. Kanakia, SwRI Project No. (33-5344-001, March 1979, 4th International Conference on Fire Safety, January 1979. Lit. no. 22-708

F10. "A Model for Combustion of Poly(Dimethylsiloxanes)," J. Lipowitz and M. Ziemelis. *Journal of Fire and Flammability*. Vol. 7, pp. 482–503, October 1976.

F11. "Flammability Tests of Askarel Replacement Transformer Fluids," R. Hemstreet, *Factory Mutual Research, Heat Release Rate*, FMRC No. 1A7R3.RC, August 1978.

F12. "Flammability of Poly(Dimethylsiloxanes) II. Flammability and Fire Hazard Properties," J. Lipowitz and M. Ziemelis, *Journal of Fire and Flammability*, Vol. 7, pp. 504–529, October 1976

F13. "PCB Alternatives—An Update," K. Linsley, IEEE, 1987, CH2479-4

F14. "Fire Safety Properties of Some Transformer Dielectric Liquids," J. Lipowitz, J. Jones and M. Kanakia, IEEE, 1979, Cl-11510-7-EL

F15. "Fire Safety Upgrades in Conjunction with Mineral Oil Decontamination," J. Goudie and R. Savard. EPRI, September 1993. Lit. no. 10-580

F16. "Combustion Properties of Contaminated Dielectric Fluids as Determined in the Cone Calorimeter," J. Goudie and R.R. Buch. IEEE/DEIS International Symposium on Electrical Insulation, Baltimore, MD, June 7–10, 1992

F17. Nine-minute video of fire testing performed by UL. Request 561 Transformer Fluid Video. Lit. no. 10-347 (For video substantiation information, request document F2.)

F18. Ten-minute video of explosion testing to gain "less flammable" UL classification. Request Explosion/UL video. Lit. no. 10-503 (For video substantiation information, request document C6.)

High Voltage Strength

H1. "Partial Discharge Characteristics of Silicone Liquids," H. Kuwahani, *et al.*, 1975 Winter Meeting, IEEE/Power Engineering Society, New York, Jan. 30, 1975, Paper #C75 236-5

H2. "Study of Dielectric Breakdown of Kraft and Aramid Papers Impregnated with Silicone," W. Brooks and T. Orbeck, Paper E-8, 1976 IEEE International Symposium on Electrical insulation, Montreal, Canada. Lit. no. 10-290

H3. "Comparative Impulse Dielectric Strength Tests of Transformer Oil and 561 Silicone Liquid," Report ET86-138-P from Ontario Hydro, Research Division, 11/24/86

H4. "Surface Breakdown Test Results of Mineral Oil and Silicone Oil with Kraft Paper and NOMEX," D.O. Wiltanen, J. Goudie, and H.A. Rojas Teran; IEEE/DEIS International Symposium on Electrical Insulation, Baltimore, MD, June 7–10, 1992

H5. "Impulse Strength Studies of Polydimethyl Siloxane Fluid." R.E. Miller, T. Orbeck, and J. Bosco; Presentation at the 1978 Winter meeting of the IEEE Power Engineering Society; New York, NY, 1/30/75

Water Contamination

W1. "Water Contamination of Silicone Filled Transformers," G. Coffman and T. Orbeck, Proceedings of the 15th Electrical/Electronic Insulation Conference, October 1981. Lit. no. 10-272

W2. "Effects of Water and Silicone Fluids," G. Vincent, Conference on Electrical Insulation & Dielectric Phenomena, Dowington, PA, Oct. 21–23, 1974. Lit. no. 10-273

Environmental

E1. "Polydimethylsiloxane: Opinion Regarding Use as Coolants in Transformers," *Federal Register*, Vol. 41, No. 112, June 9, 1976, p. 23226

E2. "The Environmental Fate and Ecological Impact of Organosilicon Materials: A Review," C. Frye, Health and Environmental Sciences, Dow Corning. Lit. no. 10-370

E3. "Disposal Options for 561® Transformer Fluid from Dow Corning," R.E. Ransom. Dow Corning. Lit. no. 10-518

Toxicological

T1. "Are There Health Risks Associated with the Use of Amorphous Silicas?" R. McCunney, Corporate Medical Director, Cabot Corp. Memo, Feb. 23, 1984

T2. "Toxicologic Classification of Thermal Decomposition Products of Synthetic and Natural Polymers," Y. Alarie, R. Anderson, *Toxicology and Applied Pharmacology,* 57, 1981

T3. "Report of Mortality Following Single Exposure to Thermal Decomposition Products of Test Samples," A. Little, Rep. C-54695, November 1985

T4. "Screening Materials for Relative Toxicity in Fire Situations," C. Hilado, *Modern Physics*, 1977

T5. "Toxicity of Pyrolysis Gases from Silicone Polymers," C. Hilado, *et al.*, *Journal of Combustion Toxicology*, Vol. 5, May 1978. Lit. no. 10-264

T6. "State-of-the-Art Review: Pyrolysis and Combustion of PCB Substitutes," SCS Engineers, Inc., EPRI (Electric Power Research Institute) E1-4503, Project 2028-12, March 1986. Lit. no. 10-293

Codes and Standards[*]

*C1. "Standard Specification for Silicone Fluid Used for Electrical Insulation," ASTM D4652-87. March 1987, 545–546

*C2. *IEEE Guide for Acceptance and Maintenance of Insulating Oil in Equipment*, C57.106-1991

*C3. *IEEE Guide for Acceptance and Maintenance of Less-Flammable Hydrocarbon Fluid in Transformers*, C57.121-1988, Table 1

*C4. *IEEE Guide for Acceptance of Silicone Insulating Fluid and its Maintenance in Transformers*, C57.111-1989, Table 1

*C5. *1991 Gas and Oil Equipment Directory*, Underwriters Laboratories

C6. "New UL Classification for Silicone Transformer Fluid," J. Goudie and S. Mort, Electrical Manufacturing Technologies Expo, June 1994. Lit. no. 10-579

C7. "Silicone Transformers: An Update on Current Product Listings, Codes and Standards," S. Mort, EPRI PCB Seminar, September 1993. Lit. no. 10-581

[*] Items F7, F8, and C1–C5 can be obtained through the appropriate group or agency.

Section 2: Safety

Section Content

2.1 Material Safety Data Sheet

A material safety data sheet (MSDS) for ***Dow Corning***® 561 Silicone Transformer Liquid is supplied when the material is shipped. Many customers will have one on file in their purchasing, procurement, or receiving department.

The health and safety information and recommendations reported on an MSDS can change periodically as new information becomes available. Therefore, the MSDS should *not* be photocopied or widely distributed.

If additional copies of the MSDS for ***Dow Corning***® 561 Silicone Transformer Liquid are needed, please contact Dow Corning Corporation to obtain copies of the most up-to-date version or visit www.dowcorning.com web site.

2.2 Health and Environmental Aspects

2.2.1 Toxicology

Oral—The oral toxicity of polydimethylsiloxane (PDMS) is extremely low. No deaths have resulted in rats at single doses as high as 30 mL/kg of body weight for 0.65–12,500 cSt viscosity grade fluids. More specifically, the 50 cSt PDMS used in ***Dow Corning®*** 561 Silicone Transformer Liquid has been dosed as high as 50 mL/kg with no observed effects. Subacute and chronic oral studies in mice, rats, rabbits, and dogs have uniformly failed to yield any results of toxicologic significance. The Food and Drug Administration (FDA) permits levels of up to 10 ppm of 350 cSt PDMS fluid to be added in many food-processing operations. It is also used as an antiflatulent in medical applications.

Skin Response—A number of human repeated-insult patch tests have been conducted with PDMS fluids. In no case has there been an indication that the materials are skin sensitizers or skin-fatiguing agents. Dermal absorption studies have yielded no absorption in significant amounts. Instead, the soothing and nonirritating action of PDMS fluid on the skin has resulted in the use of many types of silicones, including PDMS fluids, in hand creams, shaving soaps, deodorants, and cosmetics.

Eye Response—Instillation of PDMS into the eye causes transitory conjunctival redness that disappears within 24 hours. The effect is probably caused by the water-repellency of the silicone fluid that produces a feeling of dryness. This effect is a physical and not a chemical effect, which is similar to the eye sensation that appears after long exposure to the wind. It has produced no serious health problems. Touching the eyes or facial skin close to the eyes may also result in this temporary eye redness.

When handling ***Dow Corning®*** 561 Silicone Transformer Liquid, care should be taken to avoid contacting the fluid with the eye to prevent any temporary discomfort that may result.

Inhalation— ***Dow Corning®*** 561 Silicone Transformer Liquid has a very low vapor pressure and thus presents essentially no inhalation hazard. Further, in inhalation studies of pyrolysis and combustion products from ***Dow Corning®*** 561 Silicone Transformer Liquid, no significant toxicological hazards were observed when compared to normal combustion products.

2.2.2 Environmental Toxicity

All studies conducted indicate a very low order of toxicity for PDMS fluids. No evidence has been obtained to suggest accumulation in the flesh of fish or birds, and there appears to be no significant transfer of the material to the eggs of chickens. The details of the studies done are available in the literature or upon request.

2.2.3 Environmental Entry

Since ***Dow Corning® 561 Silicone Transformer Liquid*** is used in closed systems, the environmental exposure risk is relatively low even in the event of an accidental release. PDMS fluids are nonvolatile and do not evaporate to the atmosphere, thus entry points are limited to soil, surface water, landfill or a wastewater treatment plant. PDMS will preferentially adhere to soil particles so its propensity to migrate towards groundwater is extremely limited. This characteristic also simplifies clean-up since the fluid will tend to remain near the spill source.

2.2.4 Environmental Fate and Effects

The fate of PDMS is partly a function of where it enters the environment Studies have shown that PDMS will degrade into lower molecular weight compounds, primarily Me2Si(OH)2, when in contact with soils. Testing under a variety of representative conditions has confirmed this observation in a wide range of different soils, indicating that the phenomenon is widespread in nature.

Significant degradation to lower molecular weight compounds has been noted after only a few weeks of soil contact. The actual rate and extent of degradation vary as a function of soil moisture content and clay type. These lower molecular weight degradation products have been shown to further oxidize in the environment, both biologically and abiotically, to form naturally occurring substances: silica, carbon dioxide, and water.

No effects from PDMS (or its degradation products) have been observed on seed germination, plant growth/survival, or plant biomass. In addition, research has shown no adverse effects from PDMS on terrestrial life forms such as insects or birds, even under highly exaggerated exposure conditions.

Aquatic Environments—If nonvolatile PDMS fluid should enter the aquatic environment, the material attaches to particulate matter and is removed from the water column by the natural cleansing process of sedimentation. Testing on aquatic plant and animal life has revealed no ecologically significant effects, even under highly exaggerated exposure conditions. PDMS fluids do not partition back into the water column, and they have no detectable biological oxygen demand (BOD). Bioconcentration is not a significant concern with PDMS. The size of the molecules makes them too large to pass through biological membranes in fish or other organisms. Specific testing has shown that PDMS does not bioaccumulate in benthic organisms or various terrestrial species, including earthworms.

Wastewater—Municipal treatment plants are designed to facilitate the natural degradation of waste by microscopic organisms. Biomass (i.e., sludge) is generated by this degradation and eventually disposal is required. Because the water solubility of silicone fluids is essentially nil, they become a minor constituent of the sludge as they attach to suspended materials in wastewater systems. In a municipal system, treated sludge is typically incinerated, landfilled, or used as fertilizer. Wastewater treatment monitoring and simulation studies have confirmed that PDMS fluid will be almost completely absent from the treated effluent.

PDMS does not inhibit the microbial activity by which wastewater is treated. Test levels far exceeding those expected in the environment have shown no effect on the activated sludge process, other than the expected benefit of foam control. The ultimate fate of nonvolatile PDMS depends on the treatment process. If the sludge is incinerated, the silicone content converts to amorphous silica, which presents no further environmental consequence when the ash is

landfilled. When treated sludge is used as fertilizer, very low levels of PDMS can be introduced to the soil environment, where it is subject to soil-catalyzed degradation. Similar soil-catalyzed degradation can also occur if sludge-bound PMDS is landfilled. Overall, there is no evidence of any adverse effects of PDMS fluids on WWTP operations.

Using the analytical test method specified by the U.S. Environmental Protection Agency, silicone fluid discharged into a wastewater sewer will be detected as an "oil and grease" type of material. However, the test method specified by the EPA also identifies other nonhydrocarbon materials as "oil and grease" materials.

Most municipalities have an "oil and grease" concentration limit of 100–200 parts per million for each customer connected to the sewer system. Minor leaks and spills of silicone fluid are unlikely to lead to a customer's waste stream exceeding this limit. However, large spills of any material, including silicone fluid, should not be discharged to a sewer system. See Section 2.4 for more information on clean up of spills. In support of their compliance responsibilities, Dow Corning can provide suggestions to customers on how best to minimize silicone fluid losses to the sewer.

2.3 Regulatory Facts

This section includes regulatory facts that can make it easier for safety and environmental professionals to determine how ***Dow Corning®*** 561 Silicone Transformer Liquid might be regulated according to current government law.

- ***Dow Corning®*** 561 Silicone Transformer Liquid is 100% trimethyl-end-blocked polydimethylsiloxane.
- The Chemical Abstracts Service (CAS) number for the material is 63148-62-9.
- This material is not classified as hazardous when discarded under the Resource Conservation and Recovery Act (RCRA) (40 CFR 261).
- The material is halogen-free—there is no chlorine or bromine present.
- The material contains no additives such as pour-point depressants, flow modifiers, antioxidants, or thermal stabilizers.
- The material contains no hazardous ingredients as defined by Occupational Health and Safety Act (OSHA) regulations under the Hazard Communication Standard (29 CFR 1910).
- The material is not listed under SARA Title III for hazardous or toxic materials.

2.4 Spill Information

2.4.1 Minor Spills

Minor spills on paved surfaces can be cleaned using absorbent materials. Use of a suitable solvent or partial solvent will facilitate cleanup. Flammability and toxicity should be a prime consideration in the choice of a solvent to clean up spills. Solvents should not be used on asphalt surfaces since they will dissolve the asphalt.

Table 2-1. Solvents and partial solvents for silicone fluids

Solvents	Partial Solvents
Amyl acetate	Acetone
Cyclohexane	Butanol
Ethylene dichloride	Dioxane
2-Ethyl hexanol	Ethanol
Hexyl ether	Heptadecanol
Mineral spirits	Isopropanol
Naptha VM&P	
Stoddard solvent	
Toluene	
Turpentine	
Xylene	
Gasoline	
Kerosene	
Methylethyl ketone (MEK)	
Methylisobutyl ketone (MIBK)	

2.4.2 Spills on Water

Section 311 of the Federal Clean Water Act imposes strict reporting requirements when certain substances are spilled onto navigable waters.

The requirement to report is not triggered by a specified quantity of spilled material, rather it is triggered by the discharge of an amount of material that causes a sheen on the water. Thus, if PDMS fluids are spilled in large quantities on navigable waters and produce a visible sheen, the U.S. Coast Guard must be notified immediately at **1-800-424-8802**.

Since silicone fluids are nearly insoluble in water and are lighter than water, they will remain at the surface of the water and can be removed using hydrophobic materials such as polypropylene mats, pads, or booms. The polypropylene material will soak up the silicone fluid while repelling the water. Once the absorbent material becomes saturated with fluid, it can be discarded as a nonhazardous solid waste or regenerated by squeezing the pad, mat, or boom to release the fluid for disposal or recovery. For more information on recovery of silicone fluids, see Section 6.5: Recycling and Disposal of Silicone Transformer Fluid.

A silicone/water mixture can also be passed through a filter containing treated cellulose such as ABSORBENT W*, which can selectively absorb the silicone fluid while allowing the water to pass through. Table 2-2 is a list of recommended absorbent materials and filter media for treating

* ABSORBENT W is a trademark of Minnesota Absorption Corporation.

silicone fluid that has been spilled into water.

2.4.3 *Spills on Roadways*

The chief concern in a roadway spill is the loss of tire traction caused by the lubricating action of the silicone fluid. On concrete or asphalt, silicone fluids have about the same degree of lubricity as motor oil.

Spills of silicone fluid on paved surfaces should be cleaned up as quickly as possible to avoid unnecessary spread of the material or potential contact with water or precipitation that could then require addition cleanup action. Spilled silicone fluid can be absorbed with materials that are commonly used to soak up oils and solvents. These include plastic fibers and pads, cellulose-based fibers and granules, and expanded clay solids. In an emergency, dry sand can be used, but it is less absorbent than the other types of materials.

The choice of absorbent may be dictated by the final disposal option. For example, the silicone fluid/absorbent mixture may be landfilled as nonhazardous solid waste, provided there is no free liquid in the absorbent mixture. If the landfill operator prefers a nonbiodegradeable absorbent for burial, the plastic fiber or expanded clay would be a better choice than biodegradable cellulose. If incineration was selected as the final disposal option, the cellulose product would be preferred since it would be fully combusted and would not contribute to ash residue.

For a silicone fluid spill on a paved surface, absorption of the fluid followed by thorough sweeping of the surface with clean absorbent should be adequate to prevent fluid runoff if the surface is subsequently wetted with water. Solvent cleaning of roadway surfaces is usually unnecessary. Residual silicone will attach to the paving material and act as a water-repellent agent.

The time required to remove ***Dow Corning***® 561 Silicone Transformer Liquid depends on the physical absorbent and the amount of fluid present. Periodic replenishment with fresh absorbents speeds up the removal.

2.4.4 *Spills on Soil*

A minor spill of ***Dow Corning***® 561 Silicone Transformer Liquid on soil can be cleaned up by removal of the soil until there is no visual discoloration of the remaining soil. In most states, the collected discolored soil can be legally landfilled as a solid nonhazardous waste.

Should such a cleanup operation be necessary, Dow Corning recommends that the appropriate state and local government officials be contacted before landfilling any material.

2.4.5 *Recommended Absorbents*

Dow Corning performed a laboratory evaluation to assess the efficiency of nine commercially available absorbents for ***Dow Corning***® 561 Silicone Transformer Liquid. Absorbency was measured for both the silicone fluid and for a water/silicone mixture.

The best results were observed using polypropylene pad materials. Polypropylene is a hydrophobic material that repels water while attracting nonpolar fluids and oils. For absorbing spilled fluid on a dry surface, a stitched polypropylene pad soaked up 12 times its original weight, while a pillow configuration absorbed 13 times its weight. Both products can be reused by

squeezing them to release most of the trapped fluid. When silicone fluid was poured onto a water surface, the polypropylene pillow and the stitched pad again performed the best.

Products that absorbed the least amount of fluid included ground corn cobs (SLICKWIK), untreated cellulose (ABSORBENT GP), and cotton fiber (Conwed Sorbent Rug). These results are summarized in Tables 2-2 and 2-3. Expanded clay and vermiculite (kitty litter) products were not tested since loose products are not practical for absorbing and recovering silicone fluids on water surfaces.

The better performing absorbents were able to selectively remove 90–95% of the fluid from the surface of the water. To remove any remaining visible sheen, best results were achieved by passing the mixture through a filter packed with treated cellulose fiber (ABSORBENT W). This second filtration/absorption step reduced the silicone content in the water to below 10 ppm.

Table 2-2. Relative performance of absorbents with ***Dow Corning®*** 561 in water

Rank	Type	Product Name	Supplier	Contact
1	Polypropylene pillow	PIL 203 J	New Pig Corporation	800-468-4647
2	Polypropylene stitched mat	MAT212 J	New Pig Corporation	800-468-4647
3	Polypropylene mat pad	MAT215 J	New Pig Corporation	800-468-4647
4	Polypropylene quilted pad	MAT403 J	New Pig Corporation	800-468-4647
5	Ground corn cobs	SLICKWIK®	Andersons Company	
6	Polypropylene plain pad		Hazwick	
7	Treated cellulose	ABSORBENT W®	Minnesota Absorption Corp.	612-642-9260
8	Blue cotton fiber roll	Conwed 76700 Sorbent Rug	Sansel Supply Company	216-241-0333
9	Untreated cellulose	ABSORBENT GP®	Minnesota Absorption Corp.	612-642-9260

Table 2-3. Relative performance of absorbents with ***Dow Corning®*** 561 on dry surface

Rank	Type	Performance
1	Polypropylene pillow	13×
2	Polypropylene stitched mat	12×
3	Polypropylene mat pad	10×
4	Polypropylene quilted pad	10×
5	Polypropylene plain pad	7×
6	Blue cotton fiber roll	5×
7	Ground corn cobs	4×
8	Treated cellulose	3×
9	Untreated cellulose	2×

2.4.6 Spill Containment

Federal, state, and local regulations can impose different requirements that should be reviewed. In addition, good manufacturing practices (GMP) and product stewardship policy will dictate some form of spill containment for materials that have risk factors that warrant such protection. Examples of risk exposure consideration include:

- Proximity to waterways
- Potential for fire and fire water runoff
- Potential for spillage from material transfer activities

Because silicone fluids are neutral and lighter than water, spill containment, when deemed prudent, can consist of an "over and under" baffled sump similar to a small household septic tank. This configuration will trap and retain the fluid while allowing water to pass through for routine disposal.

2.5 Fire Safety

The excellent reliability, performance, and economics of conventional fluid-filled transformers have been well established by end-users. They have a strong interest in transformer liquids that can replace askarels as well as meet present and future safety requirements.

The concept of the fire hazard of systems is replacing the narrower concept of flammability of materials. The most valid fire-hazard tests are those that evaluate the entire system under conditions that closely simulate use under realistic worst-case scenarios. The following characteristics are related to the fire hazard to buildings and people:

- Heat release
- Smoke and fire gases
- Fire growth/flame spread
- Arc gases
- Oxygen depletion
- Ease of ignition
- Extinguishment

Most of the current fire-hazard data for transformer fluids has been generated by conducting large-scale pool-fire tests.

2.5.1 Pool-Fire Burning Characteristics

The effect of the diameter of the burning pool of fluid on the combustion rate (rate of heat release) has been studied extensively for hydrocarbon fires over a wide range of pool diameters. The flame height in a hydrocarbon fire has been shown to be 2.5 times the diameter of the pool for pans 4 feet in diameter and larger. The combustion rate of silicones decreases with increasing pan size. The flame height stabilizes at 1 to 2 feet at a pan size of approximately 4 feet.

Silicone transformer fluid will reach a maximum sustained rate of heat release (RHR) after ignition. This peak value is maintained for several minutes. The RHR then decreases with time. This is in contrast to hydrocarbons that typically reach a steady-state RHR that is maintained until the material is consumed. It is the peak RHR that is reported and used to assess potential hazard. The silicone peak value is 10 to 18 times lower than the average value for hydrocarbons. Figures 2-1 and 2-2 from pan-burn studies show the characteristically different burn behavior of silicones.

The fire hazard to buildings, structures, and equipment can be assessed by the heat released. The rate of heat release is therefore important. Insurance companies in the U.S. use the RHR value to classify materials used in transformers.

By adding external heat to a pool fire, the behavior of the fluid toward an external fire can be studied. Figure 2-3 shows that the convective RHR will increase as the external heat flux is increased for two high-fire-point hydrocarbon transformer fluids. The RHR for

silicone fluid shows little increase with increasing external heat flux. The data suggest that a high-fire-point hydrocarbon could dramatically fuel a fire, but a silicone fluid would make little or no contribution.

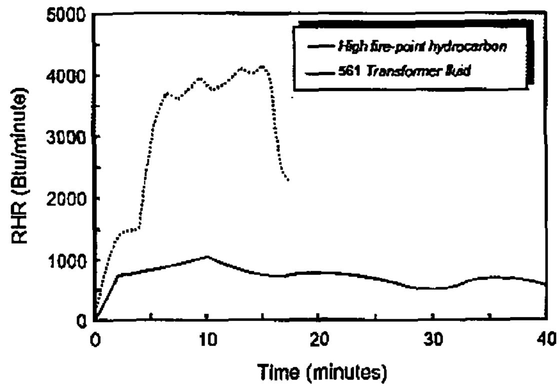


Figure 2-1. Rate of heat release for transformer fluids in 12-inch diameter pan-burn test

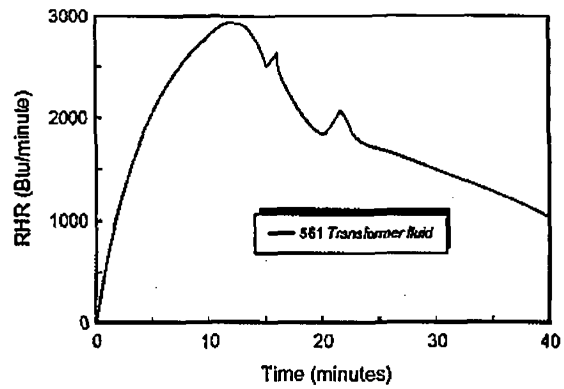


Figure 2-2. Rate of heat release for Dow Corning® 561 in 24-inch diameter pan-burn test

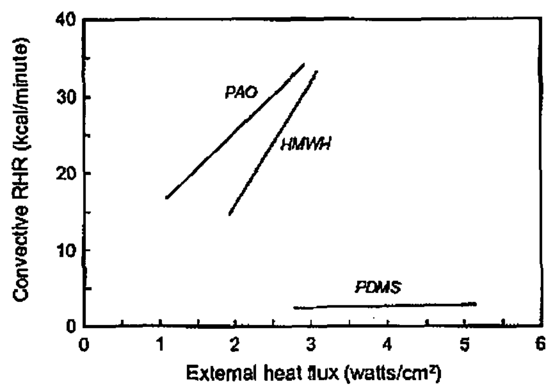


Figure 2-3. Convective rates of heat release for transformer fluids in 4-foot diameter test

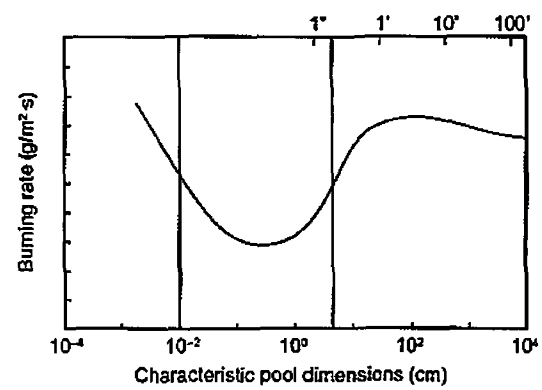


Figure 2-4. Burning rate per unit area as a function of pool (or droplet) diameter

The normalized value of RHR (RHR/area) has been used to predict the RHR of larger pan sizes. Figure 2-4 shows the relationship between burning rate and pool size for hydrocarbon burns. The RHR/m² will typically level off at a 4-foot diameter pan for hydrocarbons.

For hydrocarbons, the normalized heat release rate shows a dramatic increase as pan size increases (see Figure 2-5). The change in the normalized heat release rate as silicone burn size increases, in the same figure, is much less dramatic. The data in Table 2-4 were generated for high-fire-point hydrocarbons and *Dow Corning*® 561 Silicone Transformer Liquid.

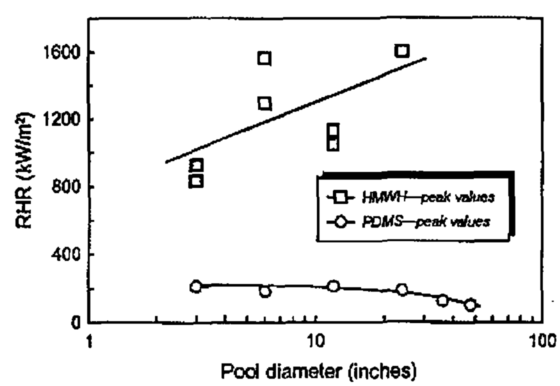


Figure 2-5. Peak rate of heat release for transformer fluids

Table 2-4. Summary of normalized RHR data (all data in kW/m^2)

	Dow Corning	FMR	Independent Test Lab
Poly-α-olefin (PAO)	1430	1020	1240
High-FP hydrocarbon	1200	1050	1270
561 Transformer fluid	65	104	109

The decrease in the RHR/area with increased pan size and the decreasing RHR with time in a pool fire result from the progressive formation of a crust of ash and silica that forms over the surface during a pool fire involving the silicone transformer fluid. The ash consists of a continuous pattern of white silica "domes" approximately 1 cm in diameter. A brown or black gel layer is formed beneath the domes. Energy feedback from the flame is inhibited sufficiently to result in self-extinguishment, leaving a pool of clear, colorless, unburned fluid beneath the ash and gel.

2.5.2 Extinguishment

Extinguishing a fire involving ***Dow Corning®*** 561 Silicone Transformer Liquid can best be accomplished using high-expansion foam, protein-based foam, or carbon dioxide or dry chemical extinguishers.

Industrial sprinkler systems are also effective. Tests using an indoor calibrated sprinkler system show that silicone fluid fires are extinguished in 20 to 30 seconds with 0.15 gpm/ft^2 of water. As is common practice, high-velocity water streams should never be used to extinguish an electrical or chemical fire.

2.5.3 Threat to Adjacent Buildings

Fires associated with transformers located outdoors can pose a severe threat to adjacent buildings. Several NFPA and IEEE standards, as well as Factory Mutual Engineering and Research Loss Prevention Data Sheet 5-4 on transformers, recommend minimum distances between transformers and adjacent buildings. Despite the availability of this information, applying the data to actual transformer installations is not well understood.

Recently, Dow Corning commissioned a study by Factory Mutual Research Corporation to determine safe distances between fluid-insulated power distribution transformers located outdoors and adjacent buildings. This "safe distance" would prevent a transformer fire from spreading to an adjacent building or structure. The study was performed for transformers with ratings up to 5000 kVA.

The general approach to the problem included:

- An examination of loss experience regarding transformer fires reported to Factory Mutual
- A theoretical analysis of fire conditions

This approach was followed for several types of transformer fluids—including mineral oil, high molecular weight hydrocarbons (HMWH), and silicone—and for common types of building construction—wooden walls, asphalt roofs, steel on steel frame (noncombustible) walls, and one-hour- or two-hour-rated walls. In the report, the results are presented in the form of graphs, tables, and/or equations.

It was found that for a typical fluid-insulated distribution transformer fire, the safe separation distance from a wooden structure is 14.8 m (49 ft) for the case of mineral oil fluid, 12 m (39 ft) for HMWH fluid, and 2.5 m (8 ft) for silicone fluid. Similar trends were reported for other building materials.

For more information on this study, contact Dow Corning Technical Service and Development or your local Dow Corning representative.

2.5.4 Smoke and Combustion Products

Smoke from silicone transformer fluid fires is typically 3 to 5 times less dense than high-fire-point hydrocarbon smoke. The smoke consists of tan-grey particulates that are almost entirely amorphous silica. The O_2-depletion rate for testing at the same smoke density has been measured at 600 liters/minute. Animal studies have indicated that the combustion products of silicone transformer fluid have little or no potential to cause serious injury, especially as compared to the affects of the combustion products of mineral oil or askarel.

2.5.5 Basic Thermochemical Properties

Table 2-5 is a summary of the thermal stability properties and burning properties of ***Dow Corning*®** 561 Silicone Transformer Liquid.

Table 2-5. Summary of thermal stability and burning properties of *Dow Corning*® 561

Property	Value
Viscosity	50 cSt
Flash point	572°F (300°C) minimum
Fire point	>600°F (350°C)
Autoignition temperature	435°C
Volatility	<0.5%
Thermal conductivity	0.00036 cal/sec·cm·°C @ 50°C
Limiting oxygen index	18.5–19% O_2
Heat of combustion	6.7 kcal/g
Rate of heat release	100–120 kcal/m^2 (4-ft pan)

2.5.6 UL Fact-Finding Report

The UL Fact-Finding Report for less flammable transformer fluids is available from Dow Corning.

Section 3: Transformer Design Information

Section Content

3.1 Dielectric Data

This section presents and discusses a variety of typical dielectric properties that are important to the performance of transformer fluids.

3.1.1 Dissipation Factor, Df

Dow Corning® 561 Silicone Transformer Liquid is a low-loss, nonpolar material as measured by dissipation factor or power factor. Dissipation and power factors are related by the following equations:

If θ is the phase angle and δ is the loss angle,

$\theta + \delta = 90°$

Power factor = $\cos\theta$

Dissipation factor = $\tan\delta$

For *Dow Corning®* 561 Silicone Transformer Liquid, typical values of the dissipation factor are approximately equal to the power factor. Figures 3-1 through 3-3 show the dissipation factor versus temperature, frequency, and voltage stress. Figures 3-4 and 3-5 compare the dissipation factor of silicone with mineral oil using two commonly used transformer insulation types.

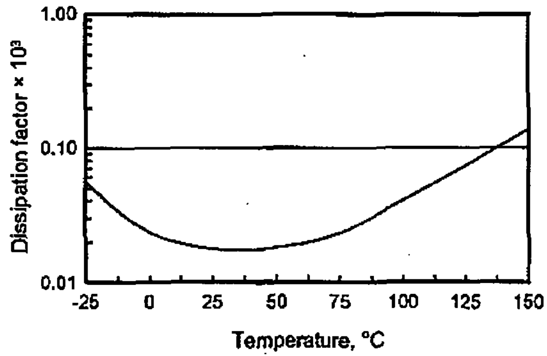


Figure 3-1. Typical dissipation factor values versus temperature

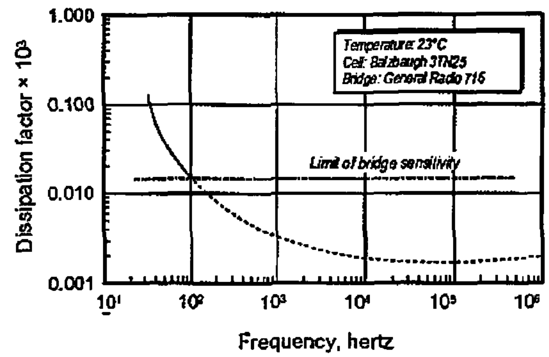


Figure 3-2. Frequency response of dissipation factor

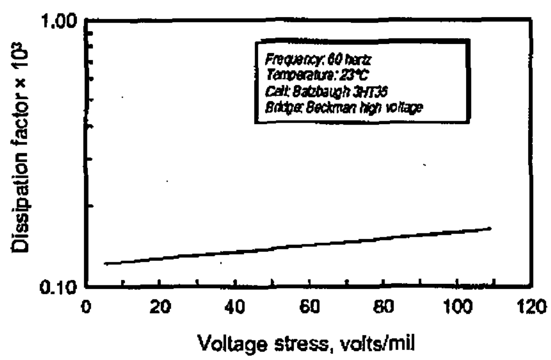


Figure 3-3. Dissipation factor versus voltage stress

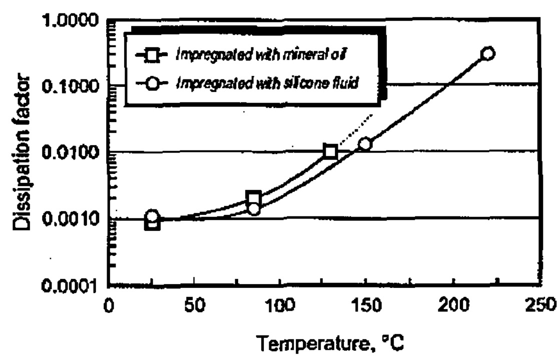


Figure 3-4. Dissipation factor of kraft paper impregnated with transformer fluids

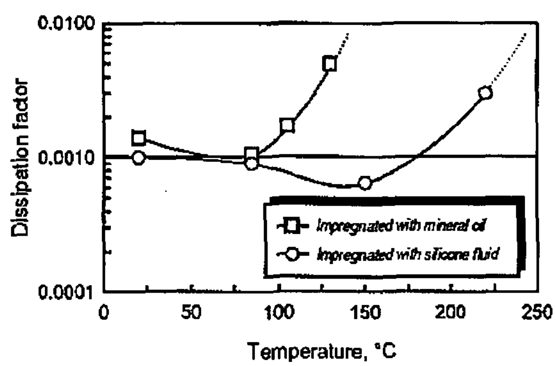


Figure 3-5. Dissipation factor of NOMEX 410 impregnated with transformer fluids*

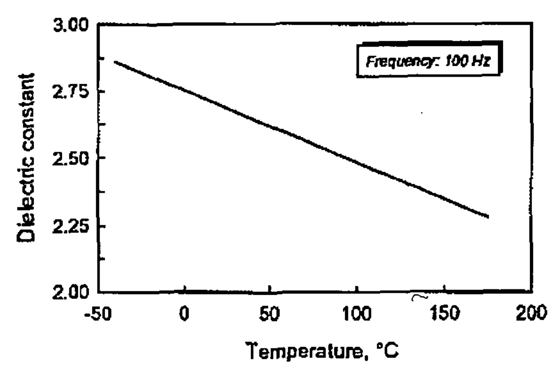


Figure 3-6. Typical values of dielectric constant versus temperature

*NOMEX is a registered trademark of E.I. Du Pont de Nemours Company, Inc.

3.1.2 Dielectric Constant, DK

Dielectric constant (sometimes referred to as permittivity, capacitivity, or specific inductive capacity) is the ratio of the capacitance of the material in a particular test configuration to the capacitance of the same configuration in air. Figures 3-6 through 3-8 show the dielectric constant of ***Dow Corning*®** 561 Silicone Transformer Liquid as a function of temperature, frequency, and voltage stress.

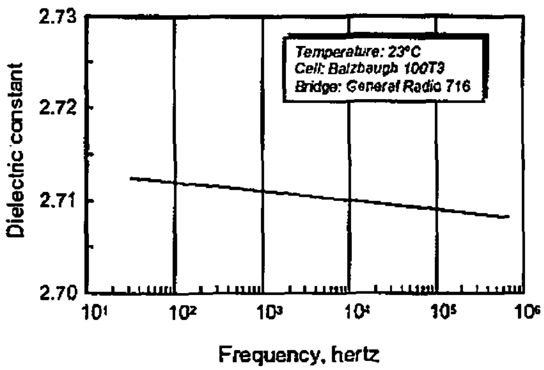


Figure 3-7. Frequency response of the dielectric constant

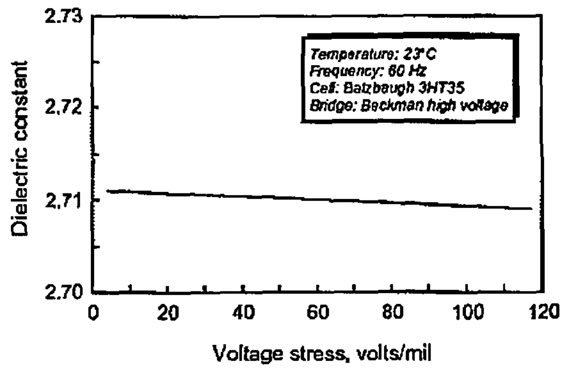


Figure 3-8. Dielectric constant versus voltage stress

3.1.3 Electrical Breakdown

The dielectric breakdown of silicone fluid according to D877 is discussed in Section 6.1, Periodic Inspection and Testing. The effect of water contamination on the results of this test is discussed in Section 6.2, Contamination. The current section deals with the impulse breakdown strength of ***Dow Corning*®** 561 Silicone Transformer Liquid and its breakdown strength in combination with paper insulation. Since the nature of this testing is such that comparisons are the most valuable, Figures 3-9 and 3-10 include data for other transformer fluids. Figure 3-11 reports the uniform field breakdown of silicone fluid at various levels of water content for two different ASTM tests.

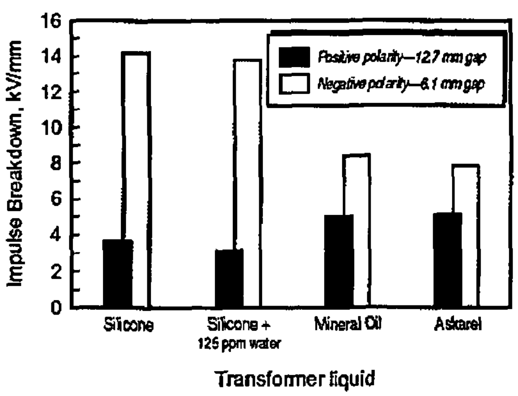


Figure 3-9. Sphere-to sphere impulse breakdown levels for transformer fluids

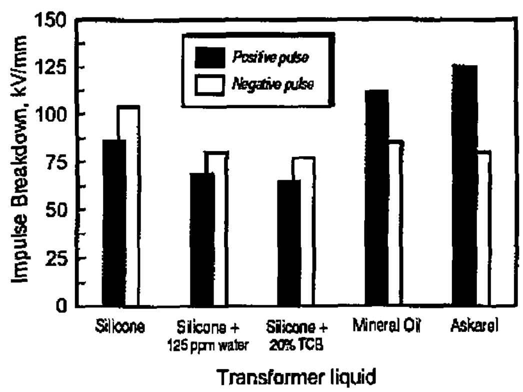


Figure 3-10. Impulse breakdown of 2x10 mil fluid-impregnated paper (sphere-to-sphere electrodes)

The electrical-breakdown data presented in Tables 3-1 through 3-4 and Figures 3-12 and 3-13 provide general information as to the relative performance of silicone in specific test configurations.

Table 3-1. Breakdown of 10-mil aramid paper/fluid composite insulation (sphere-to-ball electrodes at 25°C)

	Silicone	Mineral oil
60 Hz, 3 kV/second rate of rise		
Breakdown voltage, V/mil	1923	1966
Standard deviation, V/mil	124	233
Number of tests	12	20
60 Hz, 1 kV/minute step rise		
Withstand voltage, V/mil	1200	1205
Standard deviation	146	94
Number of tests	18	18
1.2 x 50 μs positive impulse		
Withstand voltage, V/mil	3159	3054
Standard deviation, V/mil	146	126
Number of tests	18	16

Table 3-2. Breakdown of 10-mil kraft paper/fluid composite insulation (sphere-to-plane electrodes at 25°C)

	Silicone	Mineral oil
60 Hz, 3 kV/second rate of rise		
Breakdown voltage, V/mil	1570	1894
Standard deviation, V/mil	94	195
Number of tests	75	20
60 Hz, 1 kV/minute step rise		
1-min withstand voltage, V/mil	1211	1183
Standard deviation, V/mil	78	72
Number of tests	10	12

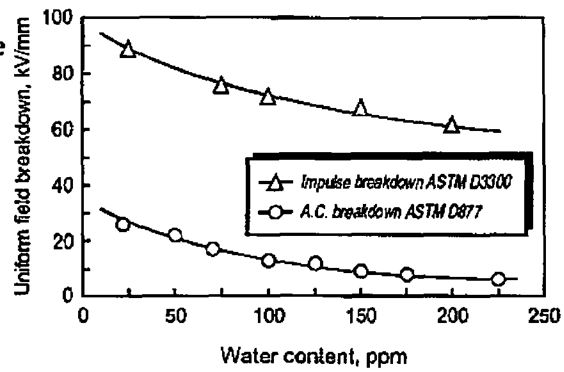


Figure 3-11. Impact of water content on uniform field breakdown for silicone fluid

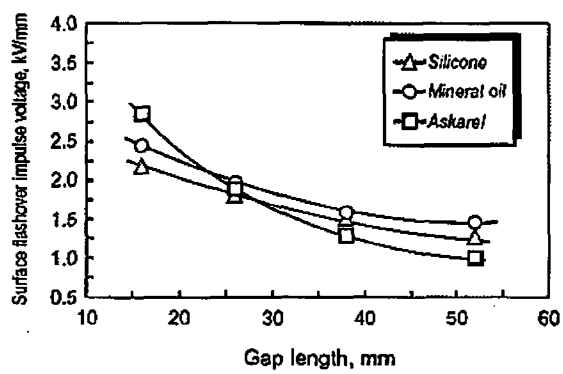


Figure 3-12. Influence of gap length on surface flashover impulse voltage—positive impulse

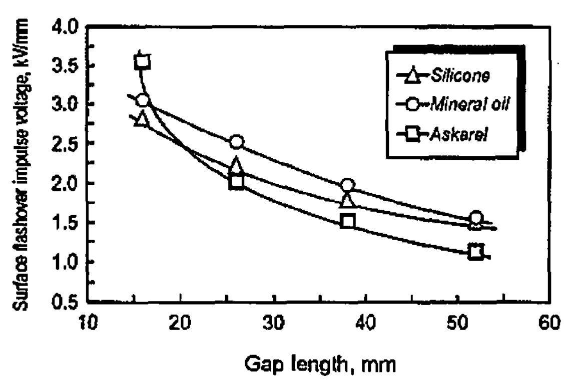


Figure 3-13. Influence of gap length on surface flashover impulse voltage—negative pulse

Table 3-3. Repeat breakdown—initial penetration from 40 kV impulse discharge; repeat strength at 60 Hz, 25°C and 3 kV/s rate of rise

	Silicone	Mineral oil	Askarel
Breakdown, mean, V/mil	942	277	0
Number of tests	18	20	19
Number of O's observed	3	10	19

Table 3-4. Breakdown strength versus humidity and water exposure—60 Hz, 25°C, and 3 kV/s rate of rise

Exposure	After vacuum	7 days @ 85% RH	60 days with water interface
10-mil kraft paper/silicone fluid composite insulation			
Breakdown voltage, mean, V/mil	1559	1442	1584
Standard deviation, V/mil	104	149	43
Number of tests	24	24	20
10-mil kraft paper/mineral oil composite insulation			
Breakdown voltage, mean, V/mil	1899	1735	1745
Standard deviation, V/mil	216	238	127
Number of tests	8	8	14

Results from a recent study using low-density kraft board and low-density NOMEX board indicated that ***Dow Corning®*** 561 Silicone Transformer Liquid and mineral oil perform similarly when subjected to negative and positive lightning impulses and 60 Hz ac power. Electrical breakdowns under positive impulse voltages are generally lower than those under negative impulse voltages. Permittivity matching appears to be a factor in the dielectric strength of the interface to impulse voltages. For ac voltages, poor resistance to partial discharges may override this effect. Figures 3-14 and 3-15 show the average breakdown voltages on low- and high-density kraft and NOMEX pressboard.

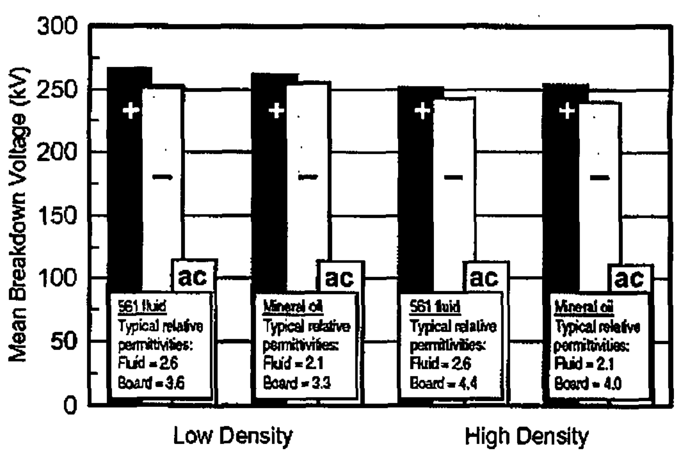


Figure 3-14. Mean breakdown voltages on both high- and low-density kraft paper board (Bars with a + symbol represent breakdown voltages with positive impulse voltages; bars with a – symbol represent negative impulses; and bars with 'ac' represent alternating current impulses.

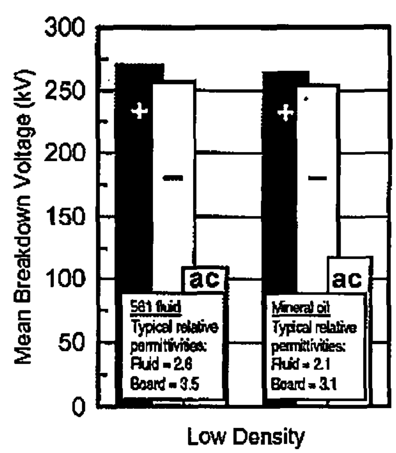


Figure 3-15. Mean breakdown voltages on low-density NOMEX paper board

3.2 Thermal Capabilities

Silicone transformer fluid differs from mineral oil and askarel in that, aside from a controlled molecular-weight distribution, it is chemically homogeneous and not a mixture containing some relatively volatile constituents. It is more heat stable than the other two fluids. These characteristics allow silicone transformer fluid to be subjected to very high temperatures—well above normal transformer operating temperatures—without creating excessive vapor pressure or corrosive by-products. Silicones are chemically inert, have good oxidation resistance, and are compatible with conventional insulating materials at transformer operating temperatures.

Table 3-5 summarizes the results of a test conducted to demonstrate the dramatic difference in thermal stability between silicone fluid and conventional transformer fluid. Open test tubes containing the two fluids were aged in a heat bath for 500 hours at 160°C. The aging caused gross volatilization and oxidation of the mineral oil; all that remained at the end of the test was a dark sludge. In contrast, no change was observed in the silicone fluid; there was no evidence of volatilization or oxidation. Although no transformer fluid is intended to be subjected to these temperatures, the data illustrate the enhanced behavior of the silicone fluid.

Table 3-5. Thermal stability of silicone and mineral oil transformer fluids (open tube, 160°C)

	Mineral oil				Silicone transformer fluid		
Aging time	Initial	24 h	100 h	500 h	Initial	100 h	500 h
Physical properties							
Appearance	Pale yellow	Medium brown	Dark brown	Black	Clear, colorless	Clear, colorless	Clear, colorless
Weight loss, %	—	14.4	33.7	75.1	—	0.053	0.141
Viscosity, cSt @ 23°C	17.8	19.0	24.5	62.0	49.0	49.5	49.0
Dielectric properties							
Dielectric constant, 100 Hz 23°C	2.26	2.27	2.29	2.46	2.72	2.72	2.72
Dissipation factor, 100 Hz 23°C	0.0014	0.00075	0.0039	0.0072	0.000018	0.000018	0.000053
Volume resistivity, ohm·cm, 23°C	8.4×10^{12}	8.7×10^{12}	2.4×10^{12}	9.5×10^{12}	7.1×10^{14}	1.1×10^{14}	5.9×10^{14}

The pronounced difference in stability between these two types of fluids can be understood by examining what takes place in these fluids at high temperatures. Mineral oil begins to volatilize and oxidize rapidly at temperatures above 105°C. Oxidation results in the formation of many objectionable degradation products. These products, which include organic acids and sludge, cause problems in a transformer by reducing the dielectric properties of the insulation and by corroding metals.

There are two modes of degradation for silicone fluid: thermal breakdown and oxidation. Thermal breakdown of silicone fluid begins at temperatures above 230°C (450°F). At these temperatures the longer polymer chains will slowly begin to degrade to form more volatile cyclic silicone material.

Oxidation of silicone fluid will take place very slowly (in the presence of oxygen) at temperatures above 175°C (342°F). When it oxidizes, silicone fluid polymerizes, gradually increasing in viscosity until gelation occurs. This process takes place *without* the formation of objectionable acids or sludges. In addition, the dielectric properties of the longer-chain silicone molecules are similar to the dielectric properties of fresh silicone fluid.

The temperatures at which thermal and oxidative degradation take place are well in excess of the hot-spot temperatures expected in 65°C-rise transformers. In the limited-oxygen atmosphere of sealed transformers, silicone transformer fluid can be used at temperature rises that are above standard rises of other transformer fluids.

The silicone transformer fluid is not expected to degrade in any significant manner over the useful service life of a 65°C-rise transformer.

Insulation systems using silicone fluid in combination with solid insulating materials having high-temperature capabilities have shown significantly improved thermal capabilities and longer insulation life. Several studies have been reported regarding such a system. Work conducted by both Westinghouse and Dow Corning examined the thermal capability and long-term performance and reliability of high-temperature capability model transformers. Researchers at Westinghouse constructed such a transformer using a 25 kVA type S-CSP 7200 240/120V Westinghouse distribution transformer.

The insulation system consisted of silicone fluid in combination with baked aromatic polyester amide/imide (OMEGA*), NOMEX paper, and glass materials. The unit was loaded electrically for life-test aging, with the loading adjusted to maintain a hot-spot temperature of 225°C, as monitored by a thermocouple in the hot-spot area of the high-voltage coil. The top liquid temperature was approximately 145°C.

The researchers reported that after 10,000 hours of operation at a hot-spot temperature of 220°C, the unit was in excellent condition. Based on IEEE Standard 345-1972, this would correspond to over 200 times the life expectancy (in hours) of a 65°C-rise distribution transformer operating at 220°C. The silicone fluid was still a clear water white in color. The results of fluid characterization tests performed during the aging study are shown in Table 3-6.

Table 3-6. Properties of 50 cSt PDMS fluid in life-test transformer at 220°C hot-spot temperature

	Original	After 1650 h	After 9000 h	After 10000 h
General condition	Clear	Clear	Clear	Clear
Dielectric strength, kV	35	28	33	28
Power factor, % @ 60 Hz, 25°C	0.007	0.01	0.004	0.006
Interfacial tension, dynes/cm	44.6	40.9	33.7	32.9
Neutralization number, mg KOH/g	0.002	0.03	0.05	0.02

A similar study performed by Dow Corning showed comparable results. In this study, two 25 kVA distribution transformers with high-temperature insulation systems were aged 10,000 hours at a hot-spot temperature of 200°C. Top liquid temperatures were approximately 105°C. After 10,000 hours of aging, the flash and fire points of the silicone fluid were 324°C and 343°C, respectively, unchanged from typical values for new fluid.

Thermal analysis data have also indicated that 50 cSt PDMS fluid is considerably more thermally stable than mineral oil. Sealed-tube thermal-aging studies of kraft paper and FORMVAR†-based enameled wire in 50 cSt PDMS fluid indicated that the useful life of both materials is similar whether aged in silicone fluid or mineral oil. However, the silicone fluid was relatively unaffected by either the degradation of the solid insulation materials or the thermal exposure.

* OMEGA is a registered trademark of Westinghouse

† FORMVAR is a trademark of Monsanto Chemical Company

3.3 Pressure Increases

When temperature increases, ***Dow Corning®*** 561 Silicone Transformer Liquid expands more than mineral oil or askarel. Classical gas-compression/pressure equations predict that this increase will create higher pressures in silicone-filled transformers than those observed in askarel-filled units. Relief valves, lower fluid levels, and tank redesign have been considered. However, in pressure versus temperature experiments comparing mineral-oil-filled, askarel-filled, and silicone-filled transformers, transformer manufacturers have found that there is actually very little difference in the final pressure developed and that the pressure developed is significantly less than predicted values.

In the laboratory, Dow Corning conducted pressure versus temperature experiments in a sealed pressure bomb and collected the data shown in Table 3-7.

These data were collected in a steel pressure bomb with an air-to-silicone fluid ratio of 0.176. When the bombs were first heated to 100°C, the pressure of the silicone-filled bomb rose to 7.25 psi, but equilibrated at 4.8 psi. The pressure of the askarel-filled bomb rose to 7.3 psi and equilibrated at 4.2 psi. Both fluids took about 23 hours to equilibrate. Although rate data were limited, it appeared that the silicone equilibrated a little faster. The pressure reduction following equilibration is probably a result of gas absorption.

These data indicate that neither the silicone nor the askarel generate the high pressures predicted. They also show that the pressure resulting from the use of silicone fluid is not sufficiently greater than the askarel liquid to be of concern in transformers.

Refer to Section 3.8, Physical Characteristics, for information on volume expansion and gas solubility.

Table 3-7. Pressure in sealed bombs containing transformer fluids

	Silicone	Askarel
Initial pressure after filling and sealing at 23°C	0.0 psig	0.0 psig
Equilibrium pressure at 100°C	4.8 psig	4.2 psig
Calculated pressure at 100°C	23.2 psig	10.3 psig
Equilibrium pressure at 0°C	–3.6 psig	–4.2 psig

3.4 Partial Discharge Characteristics

According to one study, the partial discharge inceptive field strength (PDIF) of clean silicone transformer fluid is similar to that of mineral oil presently used in transformers.[1] If the silicone transformer fluid is contaminated with water, the PDIF decreases linearly with increasing water content. That relationship is shown in Figure 3-16.

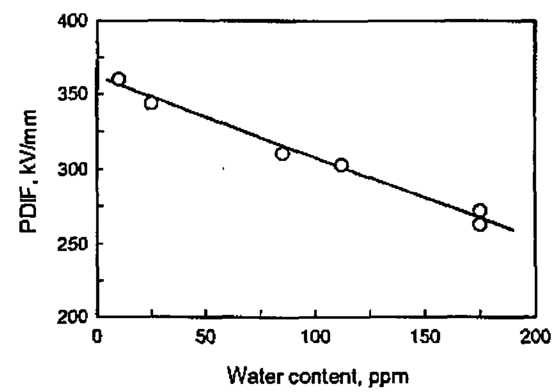


Figure 3-16. Changes in mode value of PDIF with water content Dow Corning® 561

Measurement of pulse amplitudes and rates at discharge conditions show that although the inception phenomenon is very similar in both silicone transformer fluid and mineral oil, the development and growth of the partial discharges are quite different. The chemical and physical properties of the silicone transformer fluid suppress the large discharge pulses observed in mineral oil at higher voltage stresses.

Gelled polymer substances are formed by long-time high-level partial discharges in the silicone transformer fluid. The quantity of gelled material is dependent on the total amount of the partial discharge energy dissipated in fluid. The gel consists of cross-linked polymer structures of Si–CH_2–Si, Si–OH, and Si–H.

The investigation indicated that in the design of high-voltage equipment with silicone transformer fluids, it is important to keep stress levels below the critical corona conditions that are necessary for the formation of the polymerized substances.

Studies conducted by Dow Corning have produced the partial discharge data listed in Tables 3-8 and 3-9.

Table 3-8. Discharge characteristics as determined by needle-plane screening test

	DIV, kV	DEV, kV
Dow Corning® 561	16.4	15.2
Mineral oil (10 cSt)	19.3	17.0
Askarel	20	20

Table 3-9. Discharge characteristics of impregnated 0.01 μF capacitors (two layers of 0.5-mil polypropylene film)

	DIV, volts	DEV, volts
Dow Corning® 561	2600	600
Mineral oil (10 cSt)	2200	600
Askarel	2300	1700

[1] Kuwahara, H.; Tsuruta, K.; Munemura, H.; Ishii, T.; and Shimoi, H.; "Partial Discharge Characteristics of Silicone Liquids," IEEE 1975 Winter Power Meeting, Paper No. 3, 75, 236-5.

3.5 Load-Break Switching Performance

Disconnect switches and fuses are commonly applied in pad-mounted transformers. The LBORII three-phase rotary disconnect switch from ABB Transformer Components Division is a typical choice. To satisfy the demand for a fire-safe fluid in those units, an evaluation of this switch's performance in a 50-cSt dielectric-grade silicone fluid was undertaken.

The load-switching tests were performed in accordance with ANSI 037.71, "Three-Phase, Manually-Operated Sub Surface Load Interrupting Switches for AC Systems" at the PSM High Power Laboratories in East Pittsburgh, PA. Extensive material analyses were completed in Dow Corning's laboratories and in the ABB Materials Labs formerly located in Sharon, PA.

The key findings of this study were:

- All structural and gasket materials were found to be compatible with the silicone fluid from room temperature up to 125°C. These tests were performed in accordance with ASTM D-3455, "Standard Tech Methods for Compatibility of Construction with Electrical Insulating Oil of Petroleum Origin."
- No mechanical problems or visual signs of excessive wear were observed in the switch after over 11,000 operations in the silicone fluid.
- The switch and silicone fluid performed well in over 120 load-switching operations, including fully inductive load switching and currents of up to 300 A at 15 kV.
- The dielectric strength of the fluid remained above the IEEE-recommended values for continuous use in transformers throughout the tests.
- All physical properties, including the flash and fire points of the fluid, were maintained throughout the tests. No discoloration of the fluid was noted, even after exposure to temperatures up to 125°C for as long as 164 hours.
- There was no evidence of gelling of the silicone fluid.

The reports detailing this performance are available from Dow Corning and are listed in Section 1.5, Bibliographic Resources, as items P7 and P8.

3.6 Medium and Large Power Transformer Applications

Dow Corning® 561 Silicone Transformer Liquid has over 20 years of proven performance in small power transformers. These transformers have primary voltages of 69 kVA or less. However, the thermal stability and environmental and fire-safe characteristics of silicone fluid have resulted in growing interest for certain medium and large power transformer applications. Mobile transformers, for example, must deliver maximum MVA output with a minimum of size, weight, and environmental hazard for transportation over public roadways.

Medium and large power transformer applications can differ in several respects from the traditional applications of silicone fluid in small power transformers. Among these differences are higher primary voltage rating and basic impulse levels (BIL), pumped fluid cooling rather than convective flow, use of load-tap changers in the fluid and, of course, a higher power-handling capability within the unit. Care must be taken to evaluate the pertinent dielectric, lubricity, and heat-transfer properties of silicone to achieve a proper design of the unit and its components.

Lubricity requirements and effects of low-current arcing from on-line load-tap changes can drive design requirements for load-tap changers immersed in silicone fluid. Lubricity is discussed in Section 3.9.

Resistance to partial discharges and partial discharge inception and extinction field strengths, as well as surface creepage strength, can drive dielectric stress design requirements. Dielectric data for silicone fluid and comparisons with mineral oil are provided in Section 3.1. Additional data on dielectric properties of silicone fluids can be obtained by requesting copies of the technical papers listed in Section 1.5, Bibliographic Resources, under the subheading "High Voltage Strength" or by contacting the appropriate Dow Corning technical service department.

Fluid compatibility with cooling pump design and other materials of construction is also an important consideration. Types of pumps that have proven to be suitable are discussed in Section 5.4, and material compatibilities are covered in Section 3.7. Heat-transfer properties of silicone fluids are discussed and compared with mineral oil in Section 3.10.2.

3.7 Material Compatibility

Compatibility and thermal stability are closely related. Materials that are compatible at room temperature may become incompatible at elevated temperatures because of increased solvent action or chemical activity at the higher temperatures. Also, when thermal degradation of one material begins, the products of degradation may attack other materials in the insulation system. Regardless of the initial cause of degradation, the result of this type of incompatibility can be failure of the entire insulation system.

Silicone transformer fluid has acceptable compatibility with most of the materials used in askarel-filled transformers and with those used in mineral-oil-filled transformers. A large number of materials have been tested for compatibility with silicone transformer fluid. The tests vary from simple immersion to sealed-container accelerated aging to full-scale model testing. Table 3-13 is a list of many of the materials tested and found suitable in silicone transformer fluid.

Table 3-13a. Transformer materials that are compatible with silicone fluids[a]

Metals	Insulation	Plastics and resins	Wire enamels
Copper	Kraft paper	Nylon	Amide-imide
Phosphor bronze	Pressboard	Polystyrene	Polyester
Aluminum	NOMEX (polyamide paper)	Modified acrylics	Amide
Stainless steel	QUINTEX® (asbestos paper)	Polycarbonates	FORMVAR
Cold-rolled steel	MYLAR® (polyester film)	Phenolics	ALKANEX®
Hot-rolled steel	KAPTON® (polyimide film)	PTFE	
Nickel	Polypropylene film	Silicone resins	
Magnesium	Cross-linked polyethylene	Diphenyl oxides	
Zinc	Wood	Epoxies	
Cadmium	Mica	Polyesters	
Duralumin			
Titanium			
Silver			
Monel			
Tin			
Brass			

[a]Laboratory tests have shown these materials to be compatible with silicone fluids. However, as materials vary somewhat in composition from one manufacturer to another, compatibility should be evaluated for the specific combination of materials to be used.

MYLAR and KAPTON are trademarks of E.I. Du Pont de Nemours Company, Inc.

QUINTEX is a trademark of Quin-T Corporation

ALKANEX is a trademark of General Electric Company

Table 3-13b. Transformer materials of questionable compatibility (should be tested individually)

Plastic	After 30-day immersion
Cellulose acetate butyrate	Stiffens
Polyacetal	Stiffens and crazes
Polyethylene	Stress cracks
Linear polyethylene	Some stress cracks
Polyvinyl chloride	Shrinks and hardens

Care is needed to properly select seal and gasket materials. Some plasticizers can be leached from some rubber formulations by silicone fluids. *Because of the large number of formulations available, individual testing of each potential seal or gasket material is recommended.* Table 3-14 is intended as a guide to the selection of seal and gasket materials.

Table 3-14. Compatibility ratings for seal and gasket materials

Material	Not compatible	Compatible	Testing recommended
Natural rubber		✓	
KEL-F®		✓	
Fluorosilicone rubber		✓	
Silicone rubber	✓		
Neoprene			✓
TEFLON®		✓	
VITON®		✓	
G.R.S.			✓
EPDM		✓	
Nitrile rubber			✓
Buna-N	✓		
Polypropylene			✓
HYPALON®	✓		
S.B.R.			✓
E.P.R.			✓
CORPRENE®			✓

KEL-F is a trademark of Kellogg's Professional Products Inc.
TEFLON, VITON, and HYPALON are trademarks of E.I. Du Pont de Nemours Company, Inc.
CORPRENE is a trademark of Armstrong

Silicone rubber has been used as a gasket material for askarel-filled transformers. Silicone rubber and silicone transformer fluid are very similar materials. The fluid is absorbed readily into the rubber, causing swelling and loss of physical properties. Silicone-rubber parts may be found in power transformer bushing seals, top-cover gaskets, tap changers, filling ports, instrumentation, and other openings. If silicone rubber is found in a transformer, it should be replaced with a nonsilicone seal material that is approved for use with askarel.

When choosing a dielectric material with no history of either prior use or testing with silicone fluids, compatibility testing is recommended. Dow Corning Technical Service and Development representatives can advise you of appropriate compatibility screening and performance-testing methods for silicone fluid.

3.8 Physical Characteristics

3.8.1 Vapor Pressure

Vapor-pressure data for ***Dow Corning***® 561 Silicone Transformer Liquid are reported in Table 3-15. The data can be extrapolated below 1 torr using a Cox chart, such as the one shown in Figure 3-17. The vapor pressure may vary from lot to lot depending on specific conditions during manufacture. If the curve is extrapolated to very low temperatures, the vapor pressure values that fall on the extrapolated curve may be higher than are typical for the bulk fluid. These high values are due to the presence of a very small amount of low-molecular-weight silicone.

A test that is often better at low temperatures than vapor-pressure measurements is a low-temperature volatility test under vacuum. Vapor-pressure measurements begin at 2 to 4 torr. Values below these have been extrapolated.

Table 3-15. Vapor pressure of ***Dow Corning***® 561

Temperature °C	Vapor pressure torr
231	6
277	11
300	16
313	21
322	26
330	31
336	40
340	47
345	54
348	61
353	71
356	80
358	91.5
360	102.5
363	113.5
365	124.5
372	136.5
375	150

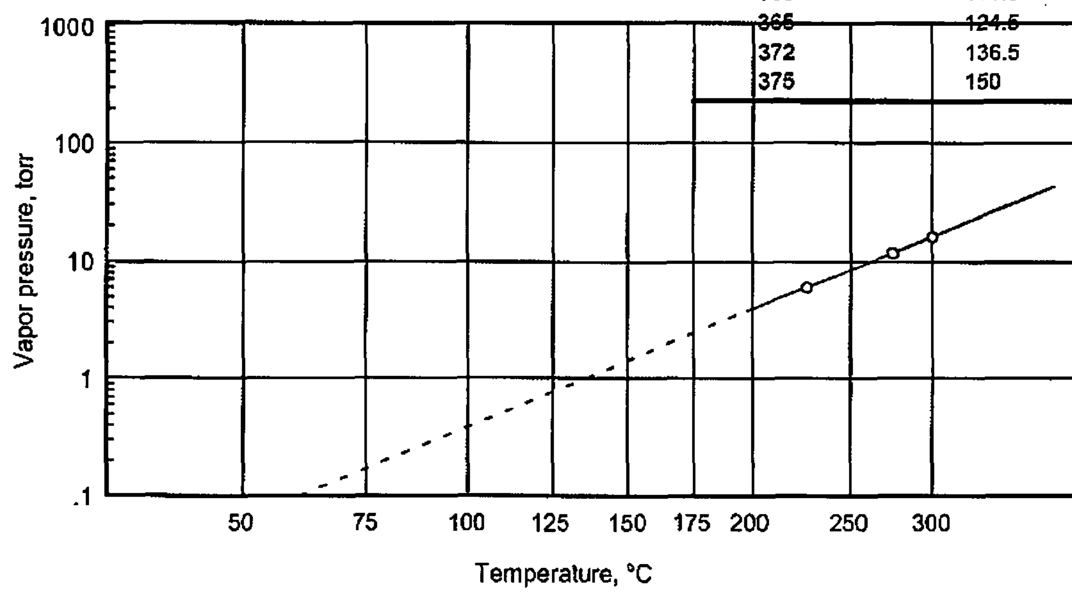


*Figure 3-17. Cox chart for **Dow Corning**® 561 Silicone Transformer Liquid*

3.8.2 Volume Expansion

The temperature coefficient of volume expansion of ***Dow Corning***® 561 Silicone Transformer Liquid is shown in Table 3-16. The relationship is shown in Figure 3-18 below. The curve may be

extrapolated above and below the given temperature with reasonable accuracy. As shown in the table, the coefficient of expansion of silicone fluid is greater than those of conventional transformer fluids.

Table 3-16. Coefficients of expansion for transformer fluids

Fluid	Coefficient of expansion ($cm^3/cm^3 \cdot °C$)
Silicone transformer fluid	0.00104
Mineral oil	0.00073
Askarel	0.00070

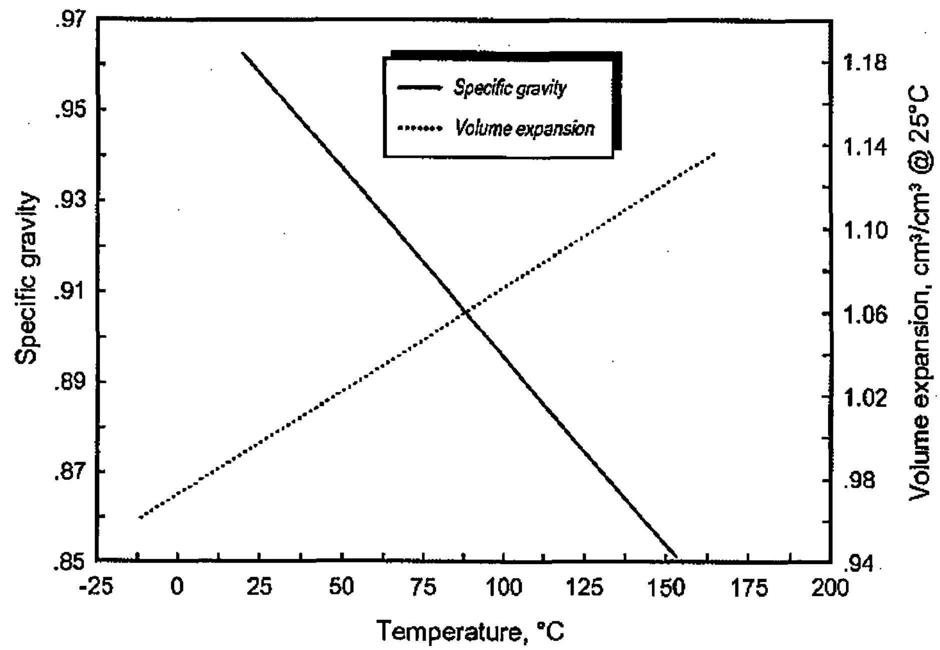


Figure 3-18. Changes in volume expansion and specific gravity of Dow Corning® 561 Silicone Transformer Liquid with temperature

Classical gas-compression versus pressure equations suggest that mineral-oil-filled and askarel-filled transformers could experience pressures in excess of their pressure ratings. However, other factors preclude this from happening. It appears that the transformer fluid absorbs excess gas as the pressure increases. Although silicone fluid expands more than mineral oil or askarel, the expansion is partially offset by its ability to absorb more gas, as shown in Table 3-17.

Table 3-17. Air solubility of transformer fluids

Fluid	Air solubility 25°C @ 1 atm
Silicone transformer fluid	16.5%
Mineral oil	10.0%
Askarel	5.7%

Section 3.3 reports laboratory pressure data that are consistent with these concepts; pressure increases in sealed pressure vessels were less than predicted and the pressure increases experienced with silicone fluids were not enough higher than askarel fluids to be of concern.

In pressure-temperature experiments in actual transformers and in 81 silicone-filled transformers monitored for a 3-year period under various service conditions, no unusual pressure or vacuum conditions developed.

3.8.3 Solubility of Gases

Table 3-18 reports solubility data for several gases in ***Dow Corning***® 561 Silicone Transformer Liquid at 80°C. The data are presented in terms of volume of gas (STP) per unit volume of silicone transformer fluid. Figure 3-19 shows the solubility of helium and nitrogen in ***Dow Corning***® 561 Silicone Transformer Liquid versus pressure.

Table 3-18. Gas solubility data for ***Dow Corning***® 561

Gas	Solubility %
H_2	8.7
CO	12
CO_2	73
CH_4	29
C_2H_2	76
C_2H_4	85
C_2H_6	108
N_2	11

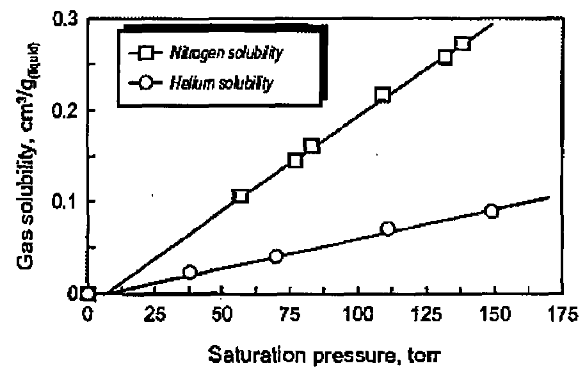


Figure 3-19. Solubility of nitrogen and helium in Dow Corning® 561

3.8.4 Viscosity-Temperature Relationship

Figure 3-20 compares the temperature-viscosity relationship of ***Dow Corning®*** 561 Silicone Transformer Liquid with common askarels and mineral oil at various temperatures. PYRANOL* A-13B3B-3 and INERTEEN† 70-30, are the only askarel formulations for which Dow Corning has viscosity-temperature data.

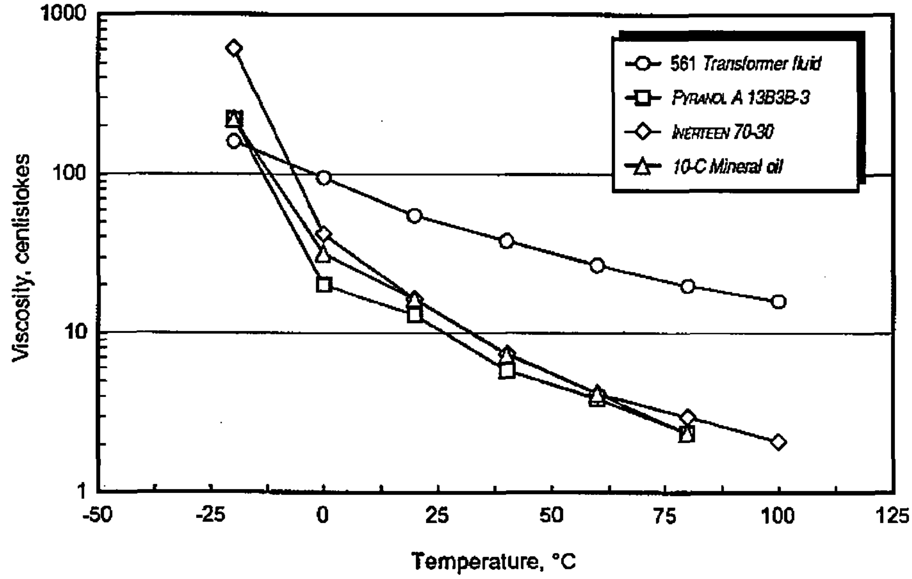


***Figure 3-20.** Viscosity-temperature relationships for transformer fluids*

* PYRANOL is a trademark of General Electric Company

† INERTEEN is a trademark of Westinghouse, Inc.

3.8.5 Specific Heat

Figure 3-21 shows how the specific heat of ***Dow Corning***® 561 Silicone Transformer Liquid changes with changes in temperature. Over a normal operating temperature range the specific heat is fairly constant.

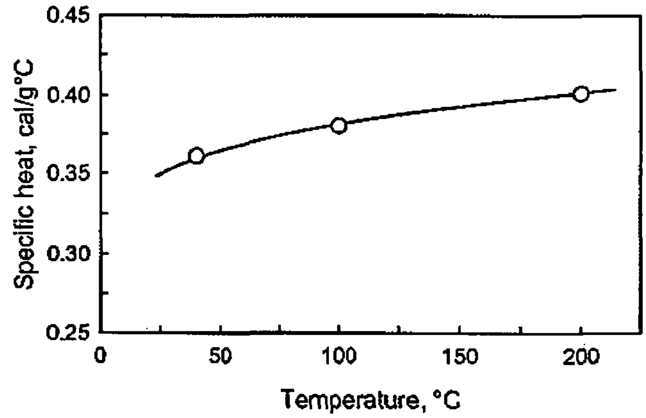


*Figure 3-21. Specific heat of **Dow Corning**® 561*

3.8.6 Density

The change in density of ***Dow Corning***® 561 Silicone Transformer Liquid with respect to temperature can be determined from Figure 3-18 since:

$$\rho = \text{Specific gravity} \times \rho_{water}$$

Alternatively, density can be determined using the following equation:

$$\rho_T = \rho_{25}\left(\frac{1}{1+0.00036(T-25°C)}\right)$$
$$\text{where } \rho = 0.9572 \text{ g/mL}$$

3.9 Lubricity

Polydimethylsiloxane (PDMS) is usually not recommended for use as a metal-to-metal lubricant. It lacks the lubricity required for many mechanical applications that involve sliding friction between metals. However, when rolling friction is involved, ***Dow Corning***® 561 Silicone Transformer Liquid has good lubricity and good load-carrying capacity between many common combinations of materials.

PDMS fluid is one of the best lubricants for fiber and plastic gears or bearings constructed of natural and synthetic rubber, polystyrene, phenolics, and most other plastics. However, compatibility with each these types of materials should be checked individually.

Tables 3-19, 3-20, and 3-21 contain a list of metal combinations that are rated as "poor," "questionable," and "good," respectively, when used with ***Dow Corning***® 200 fluid by Dow Corning as a lubricant. These ratings are merely for comparison; no actual measurements have been made of the absolute lubricating properties of ***Dow Corning***® 561 Silicone Transformer Liquid. The data result from a simple sliding test between two metal plates.

Every application that uses silicone fluid as a lubricant is different, and each combination should be thoroughly tested before any final design recommendations are made.

Table 3-19. Metal combinations rated "poor" when lubricated with ***Dow Corning***® 200 fluid

Slider	Plate
Aluminum	Aluminum
	Babbitt
	Cadmium
	Steel
Babbitt	Babbitt
	Copper
	Magnesium
	Stainless steel
	Tin
Brass	Babbitt
	Copper
	Stainless steel
Bronze	Brass
	Magnesium
	Stainless steel
	Tin
Cadmium	Magnesium
Cold-rolled steel	Babbitt
	Brass
	Chromium
	Copper
	Magnesium
	Silver
	Tin
	Zinc
Magnesium	Silver
	Stainless steel
	Zinc
Nickel	Brass
	Magnesium
	Nickel
Silver	Cadmium
	Magnesium
	Silver
Tin	Brass
	Cadmium
	Magnesium
	Zinc
Zinc	Babbitt
	Chromium
	Copper
	Magnesium
	Silver
	Stainless steel

Table 3-20. Metal combinations rated "questionable" when lubricated with ***Dow Corning*®** 200 fluid

Slider	Plate	Slider	Plate	Slider	Plate
Aluminum	Stainless steel	Chromium	Brass	Copper	Stainless steel
	Silver		Cadmium	Magnesium	Aluminum
	Tin		Chromium		Babbitt
Babbitt	Aluminum		Copper		Copper
Brass	Magnesium		Magnesium		Magnesium
	Silver		Nickel	Nickel	Babbitt
Chromium	Aluminum		Silver		Cadmium
	Babbitt		Stainless steel		Copper
			Tin		Stainless steel
			Zinc		Zinc
		Cold-rolled steel	Aluminum	Tin	Silver
			Stainless steel		

Table 3-21. Metal combinations rated "good" when lubricated with ***Dow Corning*®** 200 fluid

Slider	Plate	Slider	Plate	Slider	Plate
Aluminum	Brass	Cadmium	Aluminum	Magnesium	Cadmium
	Chromium		Babbitt		Chromium
	Copper		Chromium		Nickel
	Magnesium		Cadmium		Tin
	Nickel		Chromium	Nickel	Aluminum
	Zinc		Copper		Chromium
Babbitt	Brass		Nickel		Silver
	Cadmium		Silver		Tin
	Chromium		Stainless steel	Silver	Aluminum
	Nickel		Steel		Babbitt
	Silver		Tin		Brass
	Steel		Zinc		Chromium
	Zinc	Cold-rolled steel	Cadmium		Copper
Brass	Aluminum		Graphitar		Nickel
	Brass		Nickel		Stainless steel
	Cadmium		Nylon		Steel
	Chromium	Copper	Aluminum		Tin
	Nickel		Babbitt		Zinc
	Tin		Brass	Tin	Aluminum
	Zinc		Cadmium		Babbitt
Bronze	Aluminum		Chromium		Chromium
	Babbitt		Copper		Copper
	Cadmium		Magnesium		Nickel
	Chromium		Nickel		Stainless steel
	Copper		Silver		Steel
	Nickel		Tin		
	Nylon		Zinc		
	Silver				
	Steel				
	Zinc				

3.10 Retrofill Considerations

3.10.1 Material and Component Compatibility

When retrofilling a transformer for final fill with silicone fluid, consideration should be given to the compatibility of the materials and devices within the transformer with the new fluid. The primary areas to consider involve the insulation materials, sealing and gasket materials, and any moving parts.

Silicone transformer fluid has acceptable compatibility with most of the materials used in askarel-filled and mineral-oil-filled transformers. A large number of materials have been tested for compatibility with silicone transformer liquid. Section 3.7, Material Compatibility, discusses compatibility issues in more detail and provides lists of compatible materials. Compatibility of gasket materials is more often of concern than insulation materials and can require that gaskets be changed. A list of compatible gasket materials is also provided in Section 3.7.

Lubricity is a key compatibility consideration if moving parts are present. Although mineral oil is usually an excellent lubricant, the efficacy of silicone fluid as a lubricant depends on specific circumstances. Considerations involve whether the parts in friction are metal or plastic, which metal or plastic is involved, and whether the parts involve sliding or rolling friction. Section 3.9, Lubricity, provides detailed information on the lubricity of silicone transformer fluid. This information—along with knowledge of the application such as the expected frequency of operation of a device like a switch or tap changer—will help determine the compatibility of the silicone transformer fluid.

The compatibility of oil-immersed load-break devices with silicone transformer fluid has recently been tested. Results show the acceptability of silicone fluid under arcing conditions. Specific data are given in Section 3.5, Load-Break Switching Performance.

It is strongly recommended that retrofills be undertaken only by experienced transformer service companies and only after consultation with the transformer manufacturer.

3.10.2 Temperature Rise/Heat Transfer

The effectiveness of a fluid as a heat-transfer medium is dependent not only on viscosity, but also on the following properties:

- Density
- Thermal conductivity
- Heat capacity
- Coefficient of thermal expansion

The effect of these properties is dependent on the heat-transfer mechanism within the transformer—whether it is free convection, forced convection in laminar flow, or forced convection in turbulent flow.

Although the higher viscosity of the silicone transformer fluid may tend to reduce the liquid flow, the increased density difference between cool and warm fluid will increase thermal siphoning in free-convection flow in the transformer. This observation is supported by practical experience in transformers. Table 3-22 shows heat-run data from two identical new transformers. One

transformer contained INERTEEN, a Westinghouse askarel, and the other contained ***Dow Corning*®** 561 Silicone Transformer Liquid.

Table 3-22. Heat-run data for transformer fluids in 2500 kVA, 13.8 kV, Delta 450 LV WYE transformer

Temperature rating	Transformer fluid	Load	Load losses	Rise in windings by resistance measurements		Top fluid rise
°C		percent	watts	H.V.	L.V.	°C
55	INERTEEN liquid	100	27900	50.90	50.10	49.90
65	INERTEEN liquid	100	—	60.00	60.00	56.00
55	561 Transformer fluid	100	28000	46.88	46.03	53.00
65	561 Transformer fluid	100	—	57.52	57.28	61.00

The results show that, in spite of differences in winding temperature distribution, the heat-transfer performance for ***Dow Corning*®** 561 Silicone Transformer Liquid is comparable to INERTEEN for this particular design. Table 3-23 shows heat-run data for two other transformer designs; both designs were originally filled with askarel, drained, and refilled with silicone fluid.

Table 3-23. Heat-run data for alternative transformer designs

	Askarel	Silicone
2240 kVA, 3/60 13800 - 480Y		
Primary rise, °C	61.5	62.7
Secondary rise, °C	61.7	65.9
Top fluid rise, °C	60.0	67.2
2000 kVA, 3/60 13800 - 480Y		
Primary rise, °C	57.3	54.0
Secondary rise, °C	53.8	57.5
Top fluid rise, °C	51.8	58.3

Table 3-24 lists the heat-transfer characteristics of ***Dow Corning*®** 561 Silicone Transformer Liquid compared to other commonly used transformer fluids.

Table 3-24. Heat-transfer properties of transformer fluids

Fluid	Viscosity	Specific gravity	Coefficient of expansion	Thermal conductivity	Heat capacity
	centistokes		1/°C	cal/(s·cm^2·°C/cm)	cal/g·°C
Dow Corning® 561	50.	0.960	0.00104	0.00036	0.363
AROCLOR® 1242	17.2	1.380	0.00119	0.00023	0.290
AROCLOR 1254	46.4	1.540	0.00123	0.00021	0.260
WEMCO C™ (mineral oil)	15.	0.898	0.00073	0.00036	0.488

AROCLOR is a trademark of Monsanto Chemical Company
WEMCO C is a trademark of Westinghouse, Inc.

Historically the vast majority of transformer retrofills have involved replacing askarel with silicone transformer fluid. More recently the retrofill of mineral-oil-filled transformers with silicone fluid has increased. In the retrofill of mineral-oil-filled units some consideration should be given to resulting temperature-rise performance. Depending on the transformer design and loading of the unit, it may be possible to see higher than original design rating temperatures of the fluid. The fluid itself is unaffected by typical overtemperatures. However, the aging rate of

conventional insulation materials, such as cellulose, can be affected by operation at temperatures higher than design limits.

Designers can compensate for the higher temperatures by adjusting loading levels such that the design temperature rise is not exceeded or by adding external radiator fans to increase cooling of the fluid. Mineral-oil-filled transformers retrofilled with silicone fluid that previously operated at less than full load will be less likely to exceed design temperatures.

The heat-transfer performance of silicone transformer fluid is highly dependent on the transformer design; some designs are better optimized to take advantage of the heat-transfer characteristics of the fluid. For example, if a layered-winding design is used, vertical channels will maximize the thermal siphoning effects produced by the high coefficient of expansion. Disc windings, however, are more complex and can obstruct the vertical free flow of the liquid.

Table 3-25 provides comparative fluid temperature rises of both mineral-oil-filled and silicone-filled transformers in a test station. The transformers were tested both as-new and after retrofilling with the silicone fluid. Two different size transformer pairs of similar design were used in the test. Pair 1 (consisting of units no. 1 and 2) was initially filled with mineral oil (21 gallons each) and operated at 25 kVA, 2400/4160Y, 240/480 with 1.6% and 1.7% impedance. Pair 2 (consisting of units no. 3 and 4) was initially filled with silicone fluid (29 gallons each) and operated at 50 kVA, 2400/4160Y, 240/480, with 1.8% impedance.

Table 3-25. Temperature versus load data for 25 and 50 kVA transformers

Transformer Pair No. 1—25 kVA								Transformer Pair No. 2—50 kVA							
Tested as received with mineral oil								Tested as received with *Dow Corning*® 561							
Unit 1				Unit 2				Unit 3				Unit 4			
Load %	Amb °C	Top oil °C	Oil rise	Load %	Amb °C	Top oil °C	Oil rise	Load %	Amb °C	Top oil °C	Oil rise	Load %	Amb °C	Top oil °C	Oil rise
75	28	52	24	75	29	63	34	75	26	56	30	75	26	59	33
100	30	69	39	100	30	72	42	100	28	80	52	100	26	82	54
125	31	65	34	125	31	69	38	125	31	92	61	125	31	94	63
150	32	71	39	150	32	73	41	150	28	110	82	150	28	108	80
175	23	75	52	175	23	77	54	175	24	120	96	175	24	119	95
Tested after retrofill with *Dow Corning*® 561								Retrofilled with mineral oil				Rerun with *Dow Corning*® 561			
Unit 1				Unit 2				Unit 3				Unit 4			
Load %	Amb °C	Top oil °C	Oil rise	Load %	Amb °C	Top oil °C	Oil rise	Load %	Amb °C	Top oil °C	Oil rise	Load %	Amb °C	Top oil °C	Oil rise
100	4	39	35	100	4	37	33	100	4	44	40	100	4	42	38
136	14	60	46	136	14	57	43	126	14	68	54	126	14	69	55
162	16	63	47	162	16	63	47	153	15	91	76	175	30	105	75
187	20	82	62	187	20	82	62	175	30	103	73	175	30	105	75

3.10.3 Fire Safety Considerations

When retrofilling a mineral-oil-filled transformer with silicone fluid there will always be some residual oil left in the unit. This residual oil is soluble to a certain extent in silicone transformer fluid and can decrease the flash and fire points of the fluid. Table 3-26 provides data on the effect of various levels of residual mineral oil on the flash and fire points of the transformer fluid.

The data suggest that a maximum contaminant level of 3% is allowable before the flash and fire points of the silicone fluid decline significantly. Procedures such as rinsing the drained tank with silicone fluid prior to final filling can minimize residual mineral oil. Experience has shown that retrofilled mineral-oil transformers can achieve "less-flammable" status given sufficient care in removing residual mineral oil from the tank.

Table 3-26. Effect of mineral oil contamination on flash and fire points of silicone transformer fluid

Mineral oil level %	Flash point °C	Fire point °C
0	322	>343
1	241	>343
2	229	>343
3	202	332
5	193	241
10	179	207

Section 4: Specifying 561 Transformer Fluid

Section Content

4.1 Model Specification

Dow Corning technical service engineers have compiled a model that specifiers can use to develop complete specifications for transformer fluids. The model is in outline form and is found on the following three pages. It includes references to the most common publications, standards, and classifications used to characterize the performance and safety of transformer fluids.

Section 16XXX

Transformer Liquids

1.0 Part 1—General

1.01 Section Includes

A. Mineral Oil

B. Less-Flammable Liquids

1.02 References

The publications listed below form a part of this specification to the extent referenced. The publications are referred to in the text by the basic designation only.

American Society for Testing and Materials (ASTM)

ASTM D 117	1989 Electrical Insulating Oils of Petroleum Origin
ASTM D 445	1988 Test Method for Kinematic Viscosity of Transparent and Opaque
ASTM D 2161	1987 Standards Practice for Conversion of Kinematic Viscosity to Saybolt Universal Viscosity or to Saybolt Furol Viscosity
ASTM D 2225	1992 Standard Methods Testing Silicone Fluids Used for Electrical Insulation
ASTM D 3455	1989 Test Methods for Compatibility of Construction Material with Electrical Insulating Oil of Petroleum Origin
ASTM D 3487	1988 Mineral Insulating Oil Used in Electrical Apparatus
ASTM D 4652	1992 Standard Specification for Silicone Fluid Used for Electrical Insulation

Factory Mutual Engineering and Research Corporation (FM)

FM P7825	1993 Approval Guide

Institute of Electrical and Electronics Engineering (IEEE)

ANSI/IEEE C37.71	1984 (R 1990) Three-phase, Manually Operated Subsurface Load-Interrupting Switches for Alternating Current Systems
ANSI/IEEE C57.Ill	1989 IEEE Guide for Acceptance of Silicone Insulating, Fluid and Its Maintenance in Transformers

National Fire Protection Association (NFPA)

NFPA 70	1996 National Electrical Code
NEC 450-23	Less-Flammable Liquid-Insulated Transformers
NEC 450-26	Oil-Insulated Transformers Installed Indoors
NEC 450-27	Oil-Insulated Transformers Installed Outdoors

Underwriters Laboratories Inc. (UL)

Gas and Oil Equipment Directory

EOUV	Dielectric Mediums
EOVK	Transformer Fluids

1.03 Submittals

1.03.1 Data

A. Submit Underwriters Laboratories Category EOVK Classification Marking as provided by transformer fluid manufacturer.

1.03.2 Reports

A. Submit technical report on load break switch testing in specified transformer fluid.

1.04 Operation and Maintenance Data

1.04.1 Include transformer liquid manufacturer's recommended procedures for (sampling/storage/handling/disposal/recycling).

1.04.2 Submit transformer fluid manufacturer's operation and maintenance manual.

2.0 Part 2—Products

2.01 Nonflammable Liquids

2.01.1 Do not provide nonflammable transformer liquids including askarel and insulating liquids containing polychlorinated biphenyls (PCBs) and tetrachloroethylene (perchloroethylene), chlorine compounds, and halogenated compounds.

2.02 Mineral Oil

2.02.1 Liquid shall comply with requirements as set forth in ASTM D 3487, Type II, as tested in accordance with ASTM D 117 test procedures.

2.03 Less-Flammable Liquids

2.03.1 Less-flammable liquids shall have a fire point not less than 300°C per NFPA 70.

2.03.2 Shall comply with requirements set forth in ASTM D 4652 and tested per ASTM D 2225.

2.03.3 The fluid shall be approved per Factory Mutual P7825. Total heat release rate shall not exceed 150 kW/m^2.

2.03.4 The fluid shall be classified by Underwriters Laboratories as a dielectric medium per UL category EOUV. The fluid shall also be classified as a transformer fluid per UL category EOVK. Category EOVK classification marking use restrictions for maximum allowable fault energy shall not be less than 700,000 I^2t for 45 kVA transformers ranging to 14,000,000 I^2t for 10,000 kVA transformers.

2.03.5 Less-flammable transformer liquids used as a switching medium for liquid-immersed type load-break switches shall have load-switching tests performed in accordance with ANSI/IEEE C37.71. Fire point and dielectric strength shall meet or exceed specified values in C57.111 after 120 energized load-switching operations, including full inductive load switching, and load currents up to 300 amperes at 15 kV.

2.03.6 Compatibility of less-flammable transformer liquids with sealing and gasketing materials shall be proven by tests conducted in accordance with ASTM D 3455.

2.03.7 Liquid viscosity shall not exceed 100 mm^2/s at 0°C as tested per ASTM D 445, D 2161.

3.0 Part 3—Execution

3.01 Installation

3.01.1 Electrical installations shall conform to NFPA 70 and to the requirements specified herein.

3.01.2 Indoor Installations

3.01.2.1 Mineral-oil-insulated transformers shall be installed per NEC Section 450-26.

3.01.2.2 Less-flammable liquid-insulated transformers shall be installed per NEC Section 450-23 and in compliance with either Factory Mutual listing requirements or the UL Classification Marking of the liquid.

3.01.3 Outdoor Installations

3.01.3.1 Mineral-oil-insulated transformers shall be installed per NEC Section 450-27. Safeguards and clearance requirements shall be based on Factory Mutual Loss Prevention Data Sheet 5-4/14-8.

3.01.3.2 Less-flammable liquid-insulated transformers shall be installed per NEC Section 450-23 and in compliance with either Factory Mutual listing requirements or the UL Classification Marking of the liquid.

4.2 Applicable Standards

Most of the applicable standards for transformer fluids are listed in the reference section of the model specification in the preceding text. Complete copies of these references can be obtained from the issuing organization.

4.2.1 1996 National Electrical Code

The National Electrical Code (NEC), Section 450-23, provides requirements for the installation of less-flammable liquid-filled transformers. The NEC now reflects acceptance of less-flammable fluids for outdoor transformer installations as well as indoor installations. The National Electrical Code can be requested from the National Fire Protection Agency (NFPA) by contacting:

National Fire Protection Agency
1 Batterymarch Park
P.O. Box 9146
Quincy, MA 02269-9959

Telephone: (800) 344-3555

Relevant text from the 1996 National Electrical Code is printed below.

Section 450-23

Less-Flammable Fluid-Insulated Transformers. Transformers insulated with listed less-flammable fluids having a fire point of not less than 300°C shall be permitted to be installed in accordance with (a) or (b).

(a) **Indoor Installations.** In accordance with (1), (2), or (3):

(1) In Type I or Type II buildings, in areas where all of the following requirements are met:

a. The transformer is rated 35,000 volts or less.

b. No combustible materials are stored.

c. A liquid confinement area is provided.

d. The installation complies with all restrictions provided for in the listing of the liquid.

(2) With an automatic fire extinguishing system and a liquid confinement area, provided the transformer is rated 35,000 volts or less.

(3) In accordance with Section 450-26.

(b) **Outdoor Installations.** Less-flammable liquid-filled transformers shall be permitted to be installed outdoors attached to, adjacent to, or on the roof of buildings, where installed in accordance with (1) or (2):

(1) For Type I and Type II buildings, the installation shall comply with all restrictions provided for in the listing of the liquid.

> **(FPN):** Installation adjacent to combustible material, fire escapes, or door and window openings may require additional safeguards such as those listed in Section 450-27.

(2) In accordance with Section 450-27.

(FPN No. 1): Type I and Type II buildings are defined in *Standard on Types of Building Construction*, NFPA 220-1995.

(FPN No. 2): See definition of "Listed" under Article 100.

4.2.2 1996 National Electrical Safety Code

Relevant text from the 1996 National Electrical Safety Code (NESC) is printed below. These sections also recognize the use of less-flammable transformer fluids. Copies of the NESC can be requested from IEEE at the address shown in Section 4.2.4.

Section 15. Transformers and Regulators

152. Location and Arrangement of Power Transformers and Regulators

A. Outdoor Installations

1. A transformer or regulator shall be so installed that all energized parts are enclosed or guarded so as to minimize the possibility of inadvertent contact, or the energized parts shall be isolated in accordance with Rule 124. The case shall be grounded in accordance with Rule 123.
2. The installation of liquid-filled transformers shall utilize one or more of the following methods to minimize fire hazards. The method to be applied shall be according to the degree of the fire hazard. Recognized methods are the use of less flammable liquids, space separation, fire-resistant barriers, automatic extinguishing systems, absorption beds, and enclosures.
3. The amount and characteristics of liquid contained should be considered in the selection of space separation, fire-resistant barriers, automatic extinguishing systems, absorption beds, and enclosures that confine the liquid of a ruptured transformer tank, all of which are recognized as safeguards.

B. Indoor Installations

1. Transformers and regulators 75 kVA and above containing an appreciable amount of flammable liquid and located indoors shall be installed in ventilated rooms or vaults separated from the balance of the building by fire walls. Doorways to the interior of the building shall be equipped with fire doors and shall have means of containing the liquid.
2. Transformers or regulators of the dry type or containing a nonflammable liquid or gas may be installed in a building without a fireproof enclosure. When installed in a building used for other than station purposes, the case or the enclosure shall be so designed that all energized parts are enclosed in the case grounded in accordance with Rule 123. As an alternate, the entire unit may be enclosed so as to minimize the possibility of inadvertent contact by persons with any part of the case or wiring. When installed, the pressure-relief vent of a unit containing a nonbiodegradable liquid shall be furnished with a means for absorbing toxic gases.
3. Transformers containing less flammable liquid may be installed in a supply station building in such a way as to minimize fire hazards. The amount of liquid contained, the type of electrical protection, and tank venting shall be considered in the selection of space separation from combustible materials or structures, liquid confinement, fire-resistant barriers or enclosures, or extinguishing systems.

4.2.3 ASTM Standards

The primary ASTM standards of interest in specifying silicone transformer fluids are:

- ASTM D 4652-92—"Standard Specifications for Silicone Fluid Used for Electrical Insulation," *1996 Annual Book of ASTM Standards*, Vol. 10.03, Electrical Insulating Liquids and Gases; Electrical Protective Equipment.
- ASTM D 2225-92—"Standard Methods of Testing Silicone Fluids Used for Electrical Insulation," *1996 Annual Book of ASTM Standards*, Vol. 10.03, Electrical Insulating Liquids and Gases; Electrical Protective Equipment.

Copies of these ASTM standards (and other ASTM standards) can be obtained by contacting:

ASTM
1916 Race Street
Philadelphia, PA 19103-1187

Telephone: (215) 299-5400
Fax: (215) 977-9679

4.2.4 IEEE Guide

The *IEEE Guide for Acceptance of Silicone Insulating Fluid and Its Maintenance in Transformers* (IEEE C57-111-1989) can be obtained from the Institute of Electrical and Electronics Engineers (IEEE) by contacting:

IEEE
345 East 47th Street
New York, NY 10017

4.3 Product Listings

Among the National Electrical Code requirements for less-flammable fluid-filled transformers is that the fluid must be "listed." According to the NEC, Section 70, the term 'listed' refers to:

> Equipment or materials included in a list published by an organization acceptable to the authority having jurisdiction and concerned with product evaluation, that maintains periodic inspection of production of listed equipment or materials, and whose listing states either that the equipment or material meets appropriate designated standards or has been tested and found suitable for use in a specified manner.

Currently two major agencies have established listings for less-flammable liquids per the NEC: Factory Mutual Research Corporation(FM) and Underwriters Laboratories (UL). However, each has developed somewhat different requirements. UL criteria are based on explosion prevention of the transformer tank. FM requirements involve both preventive protection of the transformer and protection of the facility structure, which are based on the burning characteristics of the liquid. Specific applications can lend themselves to the use of one or the other listing. Normally, either listing is acceptable for compliance with the NEC.

Additional information regarding product listings is available UL, FM, and Dow Corning.

4.3.1 Factory Mutual Approval

Dow Corning® 561 Silicone Transformer Liquid is approved by Factory Mutual Research Corporation and can be used indoors without additional fire protection when installed in compliance with NEC Section 450-23 and the restrictions of the FM listing. Qualification for FM approval includes testing of the rate of heat release when the fluid is involved in a fire. Heat release is analyzed with respect to the ability of the building to withstand a fire.

In testing performed by FM, ***Dow Corning®*** 561 Silicone Transformer Liquid produced the lowest heat release rates of approved materials. See Table 4-1.

Table 4-1. Heat release rates for *Dow Corning®* 561

Heat release mechanism	Heat release rate kW/m²
Radiative	25
Convective	53
Total	78

4.3.2 UL Classification Marking

Dow Corning® 561 Silicone Transformer Liquid is classified by Underwriters Laboratories as both a "dielectric medium and as less flammable per NEC 450-23." The material is also classified as a less-flammable liquid in compliance with the National Electrical Code, when used in 3-phase transformers with the following restrictions:

- Use only in 3-phase transformers with tanks capable of withstanding an internal pressure of 12 psig without rupture.

- Pressure-relief devices must be installed on the transformer tank in accordance with Table 4-2 to limit pressure build-up and prevent tank rupture from gas generation under low current arcing faults.
- Overcurrent protection having I^2t characteristics not exceeding the values in Table 4-2 must be provided for the primary circuit to limit possible high-current arcing faults. If the fuse is designed to vent during operation (such as an expulsion fuse), it shall be located external to the transformer tank.

Table 4-2. Pressure relief and overcurrent protection requirements for silicone-filled transformers

Transformer rating kVA	Pressure-relief capacity[a] SCFM@15 psig	Overcurrent protection[b] A^2s
45	35	700,000
75	35	800,000
112.5	35	900,000
150	50	1,000,000
225	100	1,200,000
300	100	1,400,000
500	350	1,900,000
750	350	2,200,000
1000	350	3,400,000
1500	700	4,500,000
2000	700	6,000,000
2500	5000	7,500,000
3000	5000	9,000,000
3750	5000	11,000,000
5000 to 10,000	5000	14,000,000

[a] Opening pressure: 10 psig maximum

[b] Additional requirement to that in Section 450-3 of 1993 NEC

Section 5: Material Handling

Section Content

5.1 Storage

As is recommended practice for all high-purity dielectric fluids, when handling, storing, sampling, and inspecting silicone transformer fluid and when operating silicone-filled transformers, every precaution should be taken to protect the silicone fluid from exposure to high humidity or moisture contamination. Shipping drums should be stored indoors in an area especially selected for this purpose. If it is necessary to store drums or cans containing silicone transformer fluid outdoors, they should be stored in a covered area or otherwise protected from the weather and direct contact with water. In exposed locations, drums should be stored with the bungs down to prevent collection of water around the bung. Drums should be kept sealed until the fluid is actually needed. Partially empty drums should be tightly resealed and stored in the same manner as above.

Bulk storage of *Dow Corning*® 561 Silicone Transformer Liquid can be protected from excess moisture by an inert gas (nitrogen) or dry-air blanketing system or a desiccant vent dryer system. The storage tank design, materials of construction, and moisture protection systems should be evaluated to determine the best arrangement at each site prior to delivery.

Bulk storage tanks should be mounted on piers above the ground and easily accessible for leak inspection. There should be a curb or dike on the ground around the tanks to contain any spills or leaks. Check with state and local agencies to determine exact containment requirements in your area.

Stainless steel is recommended as the best material of construction for piping and storage tanks. Carbon steel is adequate for piping, and carbon steel with a zinc primer or an epoxy paint-on

coating or liner is suitable for storage tanks. Fiberglass and aluminum storage tanks have also been used successfully. Because of the variety of binders and alloys available, we recommend testing the specific material of construction for suitability prior to use.

The useful lifetime of ***Dow Corning***® 561 Silicone Transformer Liquid is virtually unlimited when it is stored properly. However, *failure to properly store and protect drums or bulk storage of silicone transformer fluid as specified above can result in contamination by water.*

5.2 Bulk Handling

Loading of Tank Trucks—Proper preparation of tank trucks for receiving ***Dow Corning® 561 Silicone Transformer Liquid*** is critical. Tank trucks must be clean and moisture-free. Prior to loading, tank trucks are usually purged with dry air or nitrogen to protect the fluid from absorbing moisture from humid air inside the tank. Once loaded, the tank truck is then pressurized to approximately 5 psig. This helps to prevent the vacuum relief valve on tank truck from "breathing" outside air. Breathing is usually caused by significant outside temperature variations that will affect the relative humidity of the air within the tank truck.

Tank Truck Transfer—To completely protect the product from moisture during product transfer, the receiving site should plan the best way to vent the tank truck. A common practice is to vent the tank out of the dome area, as would be done on typical product transfers. However, this procedure will affect the product moisture specification, especially during a long transfer.

There are two methods of providing ample venting to the tank truck while keeping moisture under control. One way is to simply provide clean, dry compressed air or nitrogen back to the tank truck. This method can be used to unload the tank truck or it can be used in conjunction with a transfer pump.

The second method employs a closed-loop venting system. Here, the tank truck vent is connected to the storage tank vent to equalize pressure during the transfer. Making proper connections and using the correct vent hose size is very important so as not to restrict the venting between the storage tank and tank truck. Once the vents have been connected and the lines vent valves opened, the product can then be pumped into the storage tank.

5.3 Sampling

5.3.1 Sampling from Shipping Containers

The dielectric strength of any dielectric fluid is affected by small amounts of certain impurities, particularly water. To avoid contamination and to obtain accurate test results, it is important that great care be taken in obtaining and handling samples. Poor dielectric test results that have been reported in the field have often been found, on investigation, to have resulted largely from careless handling. The following instructions, based on specifications from the American Society for Testing Materials (ASTM), must be followed to ensure accurate results.

Sample Bottle—The sample container should be made of glass, of at least 16 oz capacity, and should be clean and dry. Glass bottles are preferable to a metal container since glass may be examined to verify that it is clean. It also allows visual inspection of the silicone transformer fluid for separated water and solid impurities before testing.

The clean, dry bottle should be thoroughly rinsed with Stoddard solvent (or another suitable solvent) that has previously withstood a dielectric test of at least 25 kV in a standard test cup and then allowed to drain thoroughly. It is preferable to heat both the bottle and cap to a temperature of 100°C (212°F) for 1 hour after draining. The bottle should then be tightly capped and the neck of the bottle dipped in melted paraffin to seal.

Glass jars with rubber gaskets or stoppers must not be used. Silicone transformer fluid may easily become contaminated from the sulfur in natural rubber. Polyethylene-lined caps are preferred.

Thieves for Sampling—A simple and convenient "thief" can be made for sampling 55-gallon drums. The dimensions should be as shown in Figure 5-1. Three legs equally spaced around the thief at the bottom and long enough to keep the opening 1/8 inch from the bottom of the drum being sampled will help secure a representative sample. Two rings soldered to opposite sides of the tube at the top will allow you to conveniently hold the thief by slipping two fingers through the rings, leaving the thumb free to close the opening. In an emergency, a 36-inch-long piece of tubing can be used. For tank trucks and railcars, a thief that uses a trap at the bottom may be used.

The thief should be capable of reaching the bottom of the container, and the sample should be taken with the thief not more than 1/8 inch from the bottom. Thieves should be cleaned before and after use by rinsing with Stoddard solvent or another suitable solvent; be sure that no lint or fibrous material remains on them. When not in use, they should be kept in a hot, dry cabinet or compartment at a temperature not less than 37.8°C (100°F) and stored in a vertical position in a rack having a suitable drainage receptacle at the base.

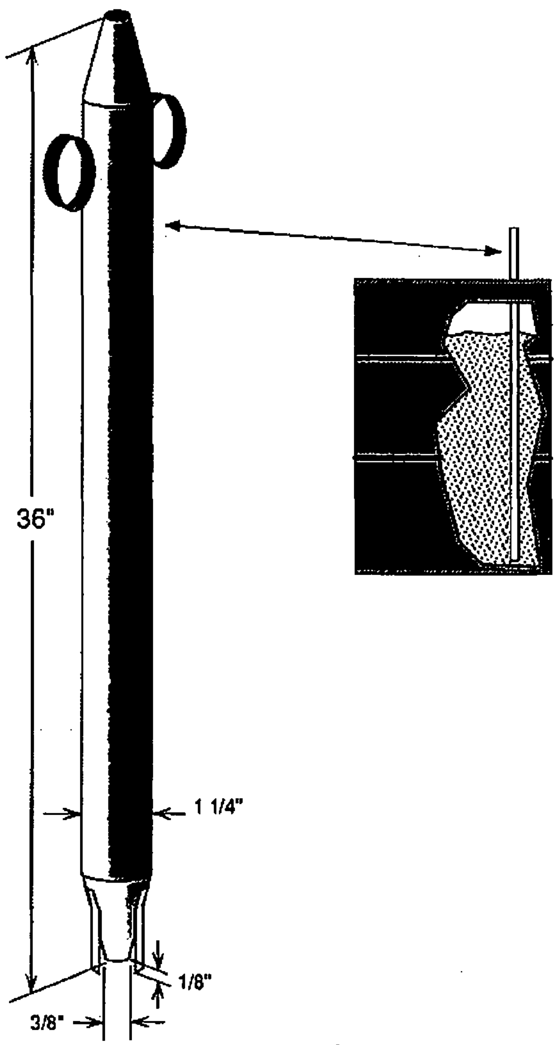


Figure 5-1. Drum thief and common technique for sampling drums

Samples should not be taken from containers that have been moved indoors until the silicone fluid is at least as warm as the surrounding air. Enough moisture can condense from a humid atmosphere on the cold fluid surface to affect the insulating properties. Sampling silicone transformer fluid from containers located outside is undesirable because of the possibility of moisture condensation; it should be avoided whenever possible. (Samples should *never* be taken in the rain.)

Recommended Procedure—The drums to be sampled should be arranged in a line with bungs up and then numbered. The bung seals should be broken and the bung removed and laid with the oil side up beside the bungholes. The unstoppered sampling container can be placed on the

opposite side of the bungholes. The top hole of the thief should be covered with the thumb, the thief thrust to the bottom of the container and the thumb removed. When the thief is filled, the top hole should be re-covered by the thumb, the thief quickly withdrawn, and the contents allowed to flow into the sample container.

The lower holes should not be closed with the fingers of the other hand. The free hand should not be used to guide the stream of silicone transformer fluid except by touching the thief, and this only when necessary. The silicone transformer fluid should not be allowed to flow over the hand or fingers before it flows into the sampling container.

When the sampling container is full, it should be closed quickly. The drum bung should be replaced and tightened, and the sampling container, now closed and under cover, should be taken to the testing laboratory as quickly as possible. After use, all thieves and sampling containers should be thoroughly cleaned as outlined above.

Tank trucks and railcars of silicone transformer fluid should be sampled by introducing the thief through the manhole on top of the car, the cover of which should be removed carefully so as not to contaminate the fluid with dirt. The sample should be taken as near as possible to the bottom of the tank car. Atmospheric precipitation should be excluded while sampling.

It may also be possible to sample the fluid through a drain valve on the bottom of the tank car. This may be done after allowing a volume of fluid equal to the volume of the drain valve to pass. This will help ensure that you obtain a representative sample.

When separate samples are being taken from a consignment or part of a consignment, care should be taken to prevent contamination of the samples. A separate thief should be used for each sample, or the thief previously used should be well drained and then thoroughly rinsed with fluid from the next container to be sampled. Any silicone transformer fluid used for rinsing should be discarded before the next sample is taken. Enough thieves should be provided to ensure thorough drainage of each thief after rinsing with silicone transformer fluid before using it to withdraw the actual sample. Two thieves are sufficient if only a few samples are involved; for a large number of samples (for example, sampling a carload of drummed silicone transformer fluid), six or more thieves are desirable.

When one average sample of a consignment or batch is being taken, the same thief may be used throughout the sampling operation, and it is not necessary to rinse the thief with fluid before obtaining any of the portions that go to make up the total average sample.

Quantity of Sample—It is recommended that one 16-oz bottle of silicone fluid be taken as a sample for dielectric tests, and a 1-quart sample be taken when complete physical and chemical tests are to be made. At least one sample should be taken from each tank car of silicone fluid. One sample may be taken from each drum or, if desired, a composite sample may be made by combining samples from all drums, provided all drums are airtight. When the bung is first loosened, you should hear a hissing sound, indicating that the drum is airtight. If the test of the composite sample is unsatisfactory, individual samples from each of the drums must be tested.

When drums have been stored exposed to the weather, a sample from each drum should be tested. The sample should be examined for separated water. If water is noted, refer to Section 6.2, Contamination. If water appears in samples taken from a tank car, follow the same procedure.

5.3.2 Sampling from Apparatus

When taking samples of silicone transformer fluid from apparatus in which a thief cannot be used, use the sampling valve and follow the procedure outlined above as far as is practical.

Care should be taken to procure a sample that fairly represents the silicone transformer fluid at the bottom of the tank. A sufficient amount of fluid should be drawn off before the sample is taken to ensure that material in the sampling pipe is not sampled. For this reason, the valve and the drain pipe should be sufficiently small to be emptied with convenience and yet sufficiently large to allow an even flow of fluid and avoid clogging by sediment. Use of ¼-inch pipe and valves is recommended. This, of course, may be separate from the drain pipe and valve or it may be connected to the drain valve with a suitable reducer.

It is of the utmost importance that the sample of silicone fluid represents the actual condition of the silicone fluid in the apparatus. Every precaution should be taken to keep the sample and container free from contamination by impurities or moisture during the sampling process. If the apparatus is installed outdoors, care must be taken to prevent contamination of the sample by precipitation.

A glass bottle is recommended as a sample container, so that any water present may readily be visible. If the sample contains separated water, it is not suitable for dielectric testing and the sample and bottle should be discarded. A second sample should be taken after at least 2 quarts of silicone fluid have been withdrawn. If separated water is still observed in the sample then refer to Section 6.2, Contamination.

5.4 Pumping

Although pumps suitable for ***Dow Corning***® 561 Silicone Transformer Liquid are readily available, not all pumps are suitable. Taking the care necessary to properly select a pump will ensure good performance and long pump life.

The two main considerations in selecting a proper pump for silicone transformer fluid are lubricity and seal compatibility. Information on lubricity can be found under Section 3.9, Lubricity. Information necessary to select proper seal and gasket materials can be found under Section 3.7, Material Compatibility.

Pumps with metal-to-metal friction requiring lubrication by the medium being pumped will either be unacceptable in silicone or will result in excessive wear and short pump life. Gear pumps and helical pumps are examples of this type. Pump suitability should be confirmed by the pump manufacturer. It is also possible to evaluate the pump's suitability by circulating a small quantity of silicone transformer fluid through the pump for an extended period of time and checking the pump for excessive wear.

Table 5-1 is a list of manufacturers that can provide pumps that are suitable for ***Dow Corning***® 561 Silicone Transformer Liquid. Consultation with the pump manufacturer is advised for selection of the best pump for your application. To properly size pumps, engineers should know that:

- ***Dow Corning***® 561 Silicone Transformer Liquid is essentially Newtonian at all practical shear rates.
- Specific gravity, vapor pressure, coefficient of expansion, and viscosity-temperature relationship information can be found in Section 3.8, Physical Characteristics.
- Good engineering practice dictates the addition of a filter between a pump and a piece of electrical equipment. Other engineering considerations may include appropriate meters, valves, and other relief or control devices.

Table 5-1. Pump manufacturers

Manufacturer	Location	Phone	Types/specifications
Gorman-Rupp Ind.	Bellville, OH	(419) 886-3001	Centrifugal, magnetic drive—specify O-ring seal material
March Manufacturing	Glenview, IL	(847) 729-5300	Centrifugal—specify seal material
Blackmer Pump Co.	Grand Rapids, MI	(800) 759-4067	Rotary positive displacement—specify seal material
Goulds Pumps, Inc.	Seneca Falls, NY	(315) 568-2811	Centrifugal pumps—mechanical seals
Viking Pump Division	Cedar Falls, IA	(319) 266-1741	Rotary gear pumps—specify silicone service

5.5 Filling Transformers

Before putting a new transformer into service, verify that the transformer tank is free of moisture and any other foreign material.

Procedures to be used for filling transformers with ***Dow Corning***® 561 Silicone Transformer Liquid do not differ significantly from methods used for filling transformers with mineral oil or askarel. Although the following procedures are typical, they may not represent the only way or the best way to fill transformers with silicone fluid.

If it is necessary to fill a transformer outside, particularly on a humid or rainy day, care should be taken to prevent moisture from entering the system. To avoid condensation, the temperature inside the transformer should be kept several degrees above the outside air temperature. It is preferable to prepare and fill outdoor apparatus on a clear, dry day.

5.5.1 Filling under Vacuum

Since entrapped air is a potential problem in all fluid-filled transformers, it is desirable to fill transformers under vacuum. This is done for transformers shipped from the factory and, if practical, should be done when transformers are filled in the field. If the transformer case is designed to withstand full vacuum, an arrangement similar to that in Figure 5-2a can be used. If the transformer case has not been designed for full vacuum and you must get the maximum winding impulse strength immediately, the transformer should be filled with silicone transformer fluid under full vacuum by placing the entire transformer assembly in an auxiliary vacuum tank, as is shown in Figure 5-2b.

If you don't have an established procedure for vacuum filling transformers, the following procedures can be used regardless of whether vacuum is applied directly to the transformer case or the entire transformer is placed in an auxiliary vacuum tank.

1. Apply and maintain a continuous vacuum of 50 torr for at least ½ hour to units rated 25 kV or below, or for 4 hours to units rated above 25 kV.
2. While holding vacuum, slowly fill the transformer with silicone transformer fluid to the normal 25°C level or, where it may be impossible to gauge properly, with about 90% of the required volume.
3. Maintain the specified vacuum for at least ½ hour after filling.
4. Add sufficient silicone fluid to adjust the level to normal and seal the transformer tank. To avoid condensation on the surface of the silicone transformer fluid, do not reopen the transformer until the temperature at the top of the fluid is equal to or higher than the ambient temperature.

5.5.2 Filling without Vacuum

In cases in which the transformer can not be filled under vacuum, full voltage should not be applied to the windings for at least 24 hours after the silicone transformer fluid has been added to the transformer case. This is necessary to allow air bubbles to escape.

When practical, fill the transformer through the drain valve, as shown in Figure 5-2c, to minimize aeration, and vent the top of the transformer tank to allow air to escape. Be sure all valves and pipe connections between the main tank and any silicone-filled transformer compartments are

open to allow free circulation of both gas and fluid. Otherwise, trapped air or gas could cause the silicone-fluid level in some parts of the transformer to remain below the safe operating level.

The transformer tank and compartments, if any, should be filled at ambient temperature to the point on the gauges marked "25°C fluid level." If the ambient temperature varies greatly from 25°C (77°F) when filled, the level should be rechecked as soon as the average fluid temperature equilibrates to the ambient temperature. Silicone transformer fluid should be added to or drained from the tank to bring the level to the proper height. The transformer should never be operated or left standing, even if out of service, without the proper silicone-fluid level indicated on the gauge.

a. Filling with transformer case under vacuum

b. Filling with transformer case placed in a vacuum chamber

c. Filling from bottom when vacuum filling is not feasible

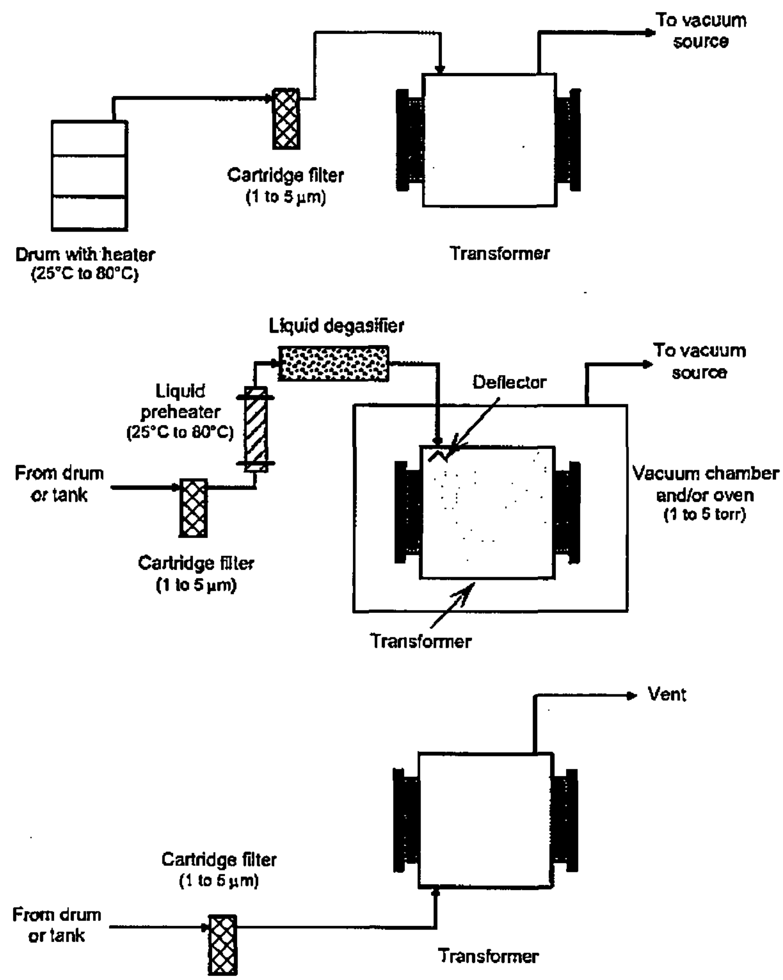


Figure 5-2. Configurations for filling transformers with fluid

5.6 Vacuum Degasification

Dielectric fluids should be filtered and degassed before being put into service in power transformers. Ideal transformer fluids are low in impurities to maintain good dielectric properties; they also must maintain very low levels of dissolved air and water. A fluid with a dissolved-air level that is well below its saturation point will dissolve air bubbles trapped inside the transformer insulation and eliminate those potential insulation system weak spots. Vacuum degasifiers can reduce both water and dissolved-air content. The efficiency of water and air removal depends on many factors such as:

- Fluid temperature
- Level of vacuum pulled
- Initial water content of fluid
- Fluid film thickness
- Time of exposure to vacuum
- The presence of boiling promoters (e.g., agitation, sharp points, rough surfaces, etc.)

Effective removal of dissolved water by vacuum degasification requires specialized equipment. Table 5-2 is a list of manufacturers who can supply portable, semiportable, or permanent vacuum-degasification equipment.

Refer to Section 3.8, Physical Characteristics, for information on vapor pressure, volume expansion, viscosity/temperature relationships, and gas solubility. This information may be important in specifying systems for silicone transformer fluid.

Simply exposing transformer fluids to vacuum or spraying the transformer fluid through a nozzle into a vacuum chamber or a transformer under vacuum may not provide sufficient degasification. Spray degasification can be inefficient because under vacuum, in the absence of air or gas, dispersed fluid droplets tend to adopt a spherical shape that minimizes surface exposure. Unless the droplets are very small, the diffusion path for degasification is too long.

For efficient degasification, a very thin film maximizes the transformer fluid's exposure to vacuum. The most efficient degasification processes use columns that spread the transformer fluid over a large surface area to create a thin film while the fluid is exposed to vacuum. Under these conditions, the fluid degases readily. Degassing columns may consist of more than one stage, with two-stage columns being quite common. The surface area of degassing columns is increased by distributing the transformer fluid onto thin-walled steel rings or saddles that fill the column. These materials, called column packings, are made in a variety of configurations such as Rashig, Pall, or Norton rings or Berl and Kirschbaum saddles.

To reduce viscosity during degassing, the transformer fluid can be heated. The appropriate temperature depends on the viscosity/temperature relationships and composition of the fluid in use.

The purpose of vacuum filling a transformer tank is primarily to provide better impregnation by removal of air from voids in the solid insulation. Degasification and drying of the transformer fluid is minimal. Consequently, transformer fluids should have acceptable dielectric properties *before* the fluid is used to fill the transformer.

Table 5-2. Vacuum processing equipment manufacturers

Manufacturer	Location	Telephone
ABVAC Inc.	St. Louis, MO	(800) 737-7937
Pall Industrial Hydraulics Corporation	East Hills, NY	(800) THE-PALL
Seaton Wilson, Div. of Systron Donner Corp.	Sylmar, CA	(818) 364-7204
Baron USA	Cookeville, TN	(615) 528-8476
Vacudyne	Chicago Heights, IL	(708) 757-5200
Enervac Corporation (www.enervac.com)	Cambridge, Ontario	(519) 623-9890
Kinney Vacuum Company	Canton, MA	(617) 828-9500

This is not intended to be a complete list of manufacturers and suppliers of vacuum systems. Consultation with technical representatives of these manufacturers and suppliers is recommended to select the best system for your operation.

5.7 Silicone Solutions for Mineral Oil Foaming

Contamination of mineral oil with some silicone fluids or other materials can cause severe foaming during processing. In severe cases, the foam is created in such large volumes that it prevents continued vacuum processing of the transformer fluid. Laboratory studies indicate that this problem exists at levels as low as 100 ppm.

The reverse problem—contamination of silicone transformer fluid by mineral oil causing foam—has not been observed. Instead, the problem with this type of contamination is a reduction of the flash and fire point of the silicone transformer fluid. See Section 6.2, Contamination, and Section 3.10, Retrofill Considerations.

The ideal situation is to avoid contaminating the transformer fluid in the first place and there are practical ways to accomplish this. Contamination can be prevented by proper inventory control and by using equipment (pumps, hoses, etc.) that is dedicated exclusively to each fluid. In many production facilities, spilled and unused transformer fluid that may accumulate along the production line is returned to a common storage tank. This practice can result in contaminated fluid.

If the same equipment *must* be used for both fluids, nonpolar solvents can be used to remove the silicone transformer fluid from equipment. However, you must replace filter media and cartridges each time you change fluids—even after solvent cleaning. The practice of sharing equipment between two different transformer fluids is risky and is often unsuccessful because of incomplete removal of the silicone fluid. Contamination of either transformer fluid with the solvent is also a potential problem.

If a vacuum process results in a foaming condition, two antifoam materials have been proven to reduce the level of foam:

- 12,500 cSt ***Dow Corning®*** 200 fluid
- 60,000 cSt ***Dow Corning®*** 200 fluid

When testing the effectiveness and practicality of Dow Corning silicone antifoams for industrial processes, an appropriate starting point is to add the antifoam to the foaming material at a concentration of 50 ppm. The results obtained at this concentration will indicate whether to increase or decrease the concentration of antifoam.

In tests using prediluted antifoams, it is sometimes desirable to repeat the test using a different diluent. Depending on the type of material that is foaming, certain diluents can alter the performance characteristics of the antifoam. Some diluents can enhance performance; others may reduce it. For example, an antifoam formulation consisting of 95% (by weight) mineral oil and 5% 60,000 cSt ***Dow Corning®*** 200 fluid can be used to eliminate the foam. This formulation works at concentrations as low as 0.2 ppm of the active antifoam in the transformer fluid. However, the formulation requires frequent agitation to maintain uniformity. In contrast, adding 12,500 cSt ***Dow Corning®*** 200 fluid with no diluent to a foaming mineral oil system may require as much as 50 ppm of the active ingredient.

Similarly, an antifoam formulation consisting of 95% (by weight) mineral oil and 5% 60,000 cSt ***Dow Corning®*** 200 fluid can also eliminate the foam at levels as low as 0.2 ppm. However, it too requires frequent agitation to maintain uniformity.

For an antifoam to work efficiently, it must be well dispersed in the fluid it is going to defoam. It cannot just be dumped into the transformer-fluid storage tank. Figure 5-3 is a flow diagram of a typical vacuum degasification system. The ideal place to apply the antifoam is at a point upstream from the filters, meters, valves, heaters, etc. The shear created by flow through these devices helps to disperse the antifoam. In addition, the antifoam may be partially retained on the filter medium and be released into the fluid gradually. The antifoam addition port can be either a point in the piping that can be opened or a fitting (e.g., a grease fitting) through which the antifoam can be injected or pumped.

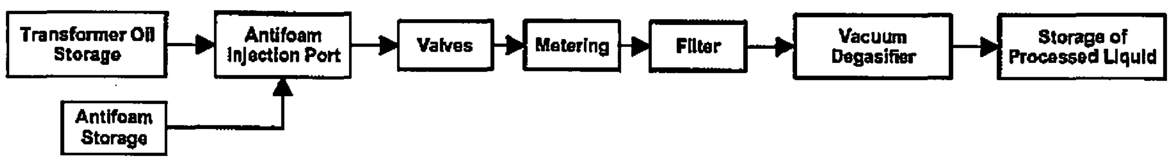


Figure 5-3. Block flow diagram of vacuum degasification system with location of antifoam injection port.

Systems vary and it may be necessary to try several different-size antifoam injections to see how much fluid can be processed before the problem returns. For a first injection, try 5 to 10 μL of antifoam formulation. Comparing antifoam injection size with gallons of foam-free fluid will allow you to compute an ideal injection size and minimize the amount of antifoam used. Usually, smaller injections made more frequently will require far less antifoam formulation than larger injections made at longer time intervals.

The following equation should be helpful in determining the amount of antifoam to add.

$$\text{Antifoam to be added} = \frac{(\text{ppm antifoam}) \times (\text{Amount of solution to be defoamed}^{a})}{(\text{\% active ingedient in antifoam}^{b}) \times (10{,}000)}$$

[a] Measure the amount of antifoam added and solution to be defoamed in the same units: lb, gal, etc.

[b] Insert 10 for 10% active, 30 for 30% active, etc.

The conversion table below should be helpful in translating the calculated amounts to common units and determining the best way to add the required amount of antifoam.

Table 5-3. Conversion table

Parts per million	Percent	Household measure per 1000 lb	Household measure per 1000 gal
1	0.0001	—	1 teaspoon
10	0.001	1 teaspoon	8 teaspoons
100	0.01	3 tablespoons	1-2/3 cups

5.8 Paint and Paintability

Silicone transformer fluid will not protect unpainted surfaces from corrosion. If severe moisture contamination occurs, corrosion could develop on unpainted surfaces. We recommend that transformers and storage tanks be primed with a corrosion-inhibiting paint, such as a zinc-chromate alkyd. Any paint is compatible with silicone transformer fluid after proper paint application and drying. However, the paint application can be affected if the surface to be painted has been contaminated with silicone fluid, just as if the surface were contaminated with motor oil, grease, or perspiration.

The best way to avoid application problems is to separate the areas where silicone fluid is handled and where the painting is done. For silicone fluid to interfere with paint application, it must get to the surface. Since the vapor pressure of ***Dow Corning*®** 561 Silicone Transformer Liquid is very low, even at 100°C, vapor contact is unlikely to contaminate surfaces. Contamination usually occurs from rags, hands, or other items that have been in contact with silicone transformer fluid.

There are two different techniques that can be used to paint surfaces that are known to be contaminated. One is to remove the silicone contamination as part of the surface preparation procedures. The other is to use silicone paint additives to alter the wetting properties of the paint, making it compatible with the silicone contamination. Both are described in detail below.

5.8.1 Surface Preparation

Although removing silicone from a contaminated surface may be somewhat more difficult than removing a conventional organic, and paintability problems may be encountered at lower levels with silicone contamination, the differences are a matter of degree, rather than of kind. In most cases, locating painting operations away from areas where silicone fluids are handled combined with routine surface preparation will prevent contamination. Should contamination occur, relatively simple cleanup procedures will render the surface paintable.

An appropriate refinishing procedure might consist of the following steps:

1. Wash the area to be repainted with a strong solution of automotive detergent in water. Many common household or industrial detergents are also satisfactory. Rinse the area thoroughly with water.
2. After the area has dried, wipe it down with a solvent such as turpentine, perchloroethylene, or xylene. Proprietary solvents (see Table 5-4) designed to remove silicones are also excellent. Disposable rags should be used so that the silicones will be removed and not redeposited.
3. Apply masking tape, grind, and buff as necessary. For better paint adhesion, lightly sand all surfaces to be repainted.
4. Carefully remove all dust from the sanding and buffing operations. Again, wipe the surface clean with clean disposable rags soaked in solvent.
5. Wipe the surface with a prepared tack rag to remove all dust and lint.
6. Spray prime coat on any bare-metal surfaces and allow the primed surfaces to dry. Spray the entire area with the final paint or lacquer coats according to usual procedure.

Table 5-4. Proprietary solvents for removing silicone contamination

Product	Supplier	Location	Telephone
Fish Eye Eliminator	E.I. Du Pont de Nemours Refinish Sales	Wilmington, DE	(800) 441-7515
No Fish Eye	Liquid Glaze, Inc.	Toccoa, GA	(706) 886-6853
Sila-Chek Additive V3 K 265	Sherwin-Williams Co.	Chicago, IL	(312) 278-7373

Procedures were developed in 1950 for repainting silicone-polished automobiles. These procedures involve washing with a strong detergent, followed by a solvent wipe. In order to prevent buildup of silicone in the solvent solution, disposable rags are recommended. These same procedures work well for the initial finishing of surfaces contaminated with silicone fluid and are recommended for the cleanup of relatively small numbers of units where a short-term contamination problem may exist. However, they would not be suitable for production-line operation.

Other methods are suitable for surface preparation on a production-line basis. For example, the feasibility of conventional vapor-degreasing techniques has been demonstrated. Standard paint panels were deliberately contaminated, cleaned in a vapor degreaser with trichloroethylene, and finished with both spray enamel and thermosetting acrylic powder.

After successfully cleaning and repainting ten heavily contaminated panels, silicone fluid was deliberately added to the bath after each panel to accelerate the buildup of fluid in the degreaser and to simulate long-term use. Twenty panels were repainted. There was no contamination caused by the vapor at silicone fluid concentrations of 11 parts of fluid in 7.51 parts of solvent.

5.8.2 Paint Additives

Silicone transformer fluid itself may be used as a paint additive in solvent-borne paints. Only very small levels are required; from 0.01% to 0.05% will do the job effectively. It is important that the 0.05% level not be exceeded to avoid altering other paint properties. Dow Corning paint additives should be used to eliminate silicone-paint problems since these additives are specially formulated to provide even dispersion and improved flexibility.

Section 6: Maintenance

Section Content

6.1 Periodic Inspection and Testing

Always follow the transformer manufacturer's recommendations for periodic inspection and testing of the insulating (or dielectric) fluid. Dow Corning recommends that—at a *minimum*—the fluid be sampled and tested after the first few days of operation, and the fluid level be checked regularly thereafter. Periodic inspection and testing of the fluid is also recommended. Such testing can alert you to a performance or reliability problem before it results in transformer failure. In fact, the ability to identify and correct problems before failure occurs is a significant advantage of fluid-filled transformers.

The inspection and testing frequency depends on the service to which the transformer is subjected. It is advisable to inspect silicone-filled transformers operating under extremely heavy loads more frequently than those in normal or light service. Referring to the station log and past test results should help identify an appropriate inspection and test frequency. The time between inspections should not be longer than one year, unless specific experience indicates that the time can be extended.

An appropriate test protocol is indicated in Table 6-1. Although acid number testing is included, this test does not reliably detect the degradation of silicones. The results could, however, suggest whether contaminants are present.

Refer to ASTM D2225 "Standard Methods of Testing Silicone Liquid for Use in Electrical Insulation" for further direction in testing silicone fluid. Visual inspection, dielectric strength, and water content are discussed below in detail.

Table 6-1. Recommended maintenance tests for silicone transformer fluid

Test	Reference	Acceptable results	Unacceptable results indicate...
Minimum Testing			
Visual inspection	ASTM D-2129	Crystal clear—free of particles	Particulates, free water, color change
Dielectric breakdown	ASTM D-877	>35 kV for fresh liquid >25 kV in transformer	Particulates or water present
Additional Recommended Testing			
Water content	Modified Karl-Fisher, ASTM D-1533	<100 ppm	Excess water present
Volume resistivity	ASTM D-1169	$>1 \times 10^{12}$	Water or contamination present
Dissipation factor	ASTM D-1533	<0.2%	Polar/ionic contamination
Viscosity	ASTM D-445	50 ± 2.5 cSt	Degradation or contamination
Fire point	ASTM D-92	>340°C	Contamination by combustible material
Acid number	ASTM D-974	<0.2	Degradation of cellulose insulation or contamination

6.1.1 Visual Inspection

Dow Corning® 561 Silicone Transformer Liquid is a water-clear, virtually odorless fluid. Because of the stability and chemical inertness of the fluid, no change in its appearance is expected over the service life of the transformer.

Any color change—such as to a green, red, or blue tint—could indicate extraction of impurities from the solid insulation. If a distinct color change is observed, check the complete range of electrical characteristics, as well as the flash and fire points, and notify the transformer manufacturer. The electrical characteristics may be unimpaired. Color change (except for white, gray, or black) is not necessarily a danger signal since the color contamination alone is unlikely to impair dielectric strength.

All samples taken for visual inspection should be obtained from the bottom of the equipment. Particulates and water will settle to the bottom of silicone transformer fluid. When sampling, it is important that the procedures outlined in Section 5.3, Sampling, be followed closely. If particulate material, gross discoloration, or free water is found during visual inspection, refer to Section 6.2, Contamination.

6.1.2 Dielectric Strength (ASTM D877)

Apparatus—The transformer and the source of energy must not be less than ½ kVA, and the frequency must not exceed 100 Hz. The rate of voltage rise should approximate 3000 volts per second. The voltage may be measured by any approved method that provides root-mean-square (rms) values.

The test cup for holding the sample of silicone fluid should be made of a material having a suitable dielectric strength. It must be insoluble in and not attacked by silicone fluid or solvents and nonabsorbent with respect to moisture, silicone fluid, and solvents.

The electrodes in the test cup between which the sample is tested should be square-edged circular discs of polished brass or copper, 1 inch in diameter. The electrodes should be mounted in the test cup with the axes horizontal and coincident, with a gap of 0.100 inch between their adjacent faces, and with the tops of the electrodes about 1¼ inch below the top of the cup.

Procedure—The spacing of electrodes should be checked with a standard round gauge having a diameter of 0.100 inch, and the electrodes then locked in position. The electrodes and the test cup should be wiped clean with dry, calendered tissue paper or with a clean, dry chamois skin and thoroughly rinsed with Stoddard solvent (or another suitable solvent) until they are entirely free from fibers.

The test cup should be filled with dry toluene, and the voltage applied, increasing uniformly at the rate of approximately 3000 volts (rms) per second until breakdown occurs. If the dielectric strength is not less than 25 kV, the cup should be considered in suitable condition for testing the silicone transformer fluid. If a lower test value is obtained, the cup should be cleaned with solvent, and the test repeated. Observe the usual precautions in handling solvents.

Evaporation of solvent from the electrodes may chill them sufficiently to cause moisture to condense on their surface. After the final rinsing, heat the cell gently to evaporate the solvent and prevent moisture condensation. This can be accomplished with a heat gun.

During testing the temperature of the test cup and the silicone fluid should be the same as that of the room—between 20 and 30°C (68 and 86°F). Testing at lower temperatures may produce misleading or nonreproducible results. For routine testing, air temperature should be maintained at 25°C and the relative humidity at 50%.

The sample in the container should be gently agitated with a swirling motion, to avoid introducing air, so as to mix the silicone fluid thoroughly before filling the test cup. This is even more important with used silicone fluid than with fresh, since impurities may settle to the bottom.

The cup should be filled with silicone transformer fluid to a height of no less than 0.79 inches (20 mm) above the top of the electrodes.

The silicone fluid sample should be gently agitated again by rocking the cup and allowing it to stand in the cup for 3 minutes before testing. This will allow air bubbles to escape.

Voltages should be applied and increased uniformly at a rate of approximately 3000 volts (rms) per second until breakdown occurs, as indicated by a continuous discharge across the gap. (Occasional momentary discharges that *do not* result in a permanent arc should be disregarded.)

Tests—Only one breakdown test may be made per cup filling. After each breakdown test, the test cup should be drained and the electrodes should be wiped clean with a lint-free disposable tissue to remove any arc decomposition products, which tend to adhere to the electrodes.

One breakdown test should be made on each of five successive fillings of the test cup. Compute the range of the five breakdown tests (maximum breakdown voltage minus minimum breakdown voltage) and multiply this range by 3. If the value so obtained is greater than the next-to-the-lowest breakdown voltage, it is probable that the standard deviation of the five breakdown tests is excessive and the probability error of their average is also excessive.

If the five values meet the criteria above, the average value should be reported as the dielectric breakdown voltage. If they do not meet the criteria, one breakdown test on each of five additional cup fillings should be made and the average value from all ten breakdown tests should be reported as the dielectric breakdown voltage of the sample. No breakdown test should be discarded. When the dielectric breakdown voltage of a fluid is to be determined on a routine basis, one breakdown test may be made on each of two fillings of the test cup. If no value is below the specified acceptance value, the fluid may be considered satisfactory, and no further tests should be required. If either of the values is less than the specified value, a breakdown test should be performed on each of three additional cup fillings, and the test results analyzed as described above.

6.1.3 Water Content

ASTM D2225 "Standard Methods of Testing Silicone Liquids Used for Electrical Insulation" specifies that water content should be determined in accordance with ASTM D1533, except that a 1:1 blend by volume of dry formamide and dry methanol is used instead of the chloroform/methanol solvent. This is known as the modified Karl-Fisher method. Silicone fluids can contain silanols or OH groups on the polymer chain. These silanols can react with normal Karl-Fisher reagent to generate water, resulting in a high reading. The modified Karl-Fisher method eliminates much of the problem.

A titration method also recognized by ASTM (and preferred by Dow Corning) is an automatic Karl-Fisher titrator, such as the Aquatest IV by Photovolt. Automatic titrators tend to reduce interference problems even further. In fact, the Aquatest IV has been very effective in accurately measuring the water content of ***Dow Corning***® 561 Silicone Transformer Liquid to within 10 ppm.

6.1.4 Gas Evolution/Arc Behavior

Evolution of Gases in Partial Discharge Tests—The absolute amount of gas that is generated in partial discharge tests is related to the specific test that is conducted. The linear relationship shown in Figure 6-1 indicates that chemical changes in the silicone transformer fluid subjected to partial discharges depends on the electrical energy delivered to the discharge site.

Gas Evolution Due to Arcing Between Electrodes—Previous studies have demonstrated that it is difficult to sustain an arc in silicone transformer fluid at low current levels. The breakdown of the silicone transformer fluid results in instant formation of solids between the two fixed electrodes. A "bridge," consisting of silica and carbon held together by gelled fluid, forms across the electrode gap. The characteristics of this bridge are directly dependent on the initial energy input of the first arc current. The arc is generally extinguished and the generation of gas is reduced or eliminated completely.

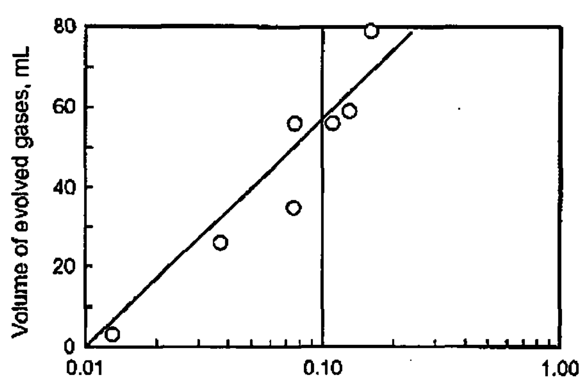


Figure 6-1. Evolved gas volume under partial discharge conditions

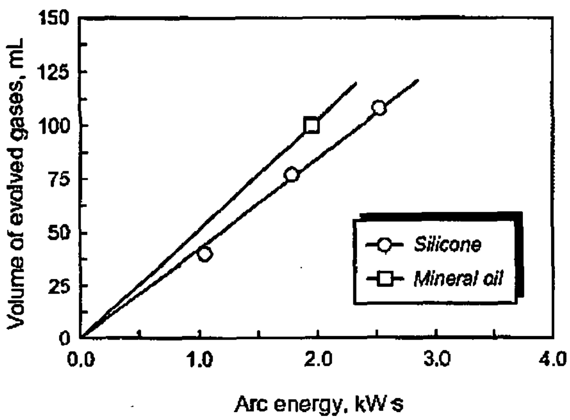


Figure 6-2. Evolved gas volume due to arcing at moderate current levels for Dow Corning® 561

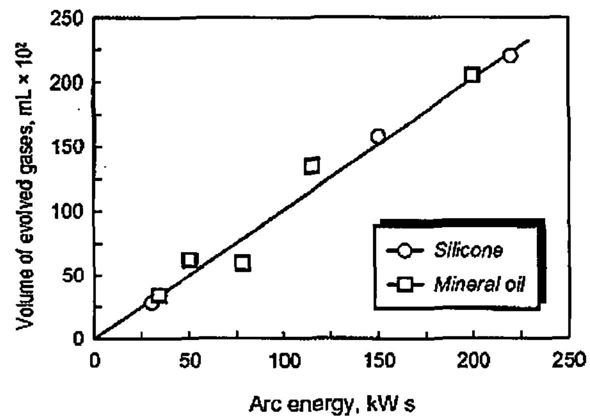


Figure 6-3. Evolved gas volume due to arcing at high current levels for Dow Corning® 561

Under arcing conditions with moderate (Figure 6-2) and high (Figure 6-3) currents, the volume of evolved gases in silicone transformer fluid is similar to that evolved by mineral oil. These data indicate that the principles used to design transformer tanks for mineral-oil service can be applied to transformer tanks for silicone fluid.

As reported in Table 6-2, analysis of the decomposition gases from low-current arcing in silicone transformer fluid showed hydrogen, H_2, to be the main component. However, substantial amounts of carbon monoxide, CO, were also evolved. Comparison tests showed that with mineral oil considerable acetylene, C_2H_2, is evolved in addition to H_2.

Table 6-2. Typical analysis of gas evolved in arc conditions with *Dow Corning® 561* and mineral oil

	Dow Corning® 561			Mineral oil		
Current	810 mA	715 mA	26.2 A	345 mA	1050 mA	15.9 A
Electrode	Rotating @ 24 rpm	Rotating @ 120 rpm	Fixed	Rotating @ 24 rpm	Rotating @ 120 rpm	Fixed
Analysis, volume percent						
H_2	74.6	75.6	77.1	65.0	68.3	73.4
CO	19.0	17.2	14.0	—	—	—
CH_4	1.7	1.2	4.0	1.2	2.0	3.5
C_2H_2	4.3	5.7	3.8	32.8	26.6	20.7
C_2H_4	0.4	0.3	1.1	0.8	1.4	2.1
C_2H_6	trace	trace	—	trace	trace	0.03
C_3H_6	trace	—	—	0.2	0.2	0.2
C_3H_8	—	—	—	trace	trace	trace
Evolved gas, mL/kW·s						
Measured	22	35	3	45	45	48
Calculated	88	89	82	65	57	47

Interpretation of Dissolved Gases in Silicone Transformer Fluid—For many years gas-in-oil analysis has been used to diagnose the condition of oil-filled transformers. The industry has attempted to apply this tool to silicone-filled transformers. Although the primary gases evolved under fault conditions in silicone fluid are similar to those evolved in mineral oil, the relative

proportions of those gases differ. Standard procedures have been established for fluid sampling, analysis, and interpretation of gas-in-oil.

At present, the IEEE Insulating Fluids Subcommittee is developing a guide for the interpretation of gases generated in silicone-immersed transformers. More information on the development and interpretation of dissolved gases is available by requesting item P10 listed in Section 1.5, Bibliographic Resources.

There is also increasing interest in applying furan analysis techniques to detect degradation within transformers. This approach can be helpful in determining whether cellulosic insulation materials are being degraded, especially when the data are interpreted in combination with gas analysis data. However, since the technique is relatively new, not all testing services offer this type of analysis, and it is especially important to select an experienced testing organization to perform the analysis.

6.2 Contamination

Fluid contamination can occur in many ways. To ensure that ***Dow Corning***® 561 Silicone Transformer Liquid performs properly, it should be maintained in as clean and pure a state as possible. Even if contamination does occur, recovery of contaminated fluid is often possible. Table 6-3 is a summary of the information discussed in detail in the sections that follow.

Table 6-3. Summary of common contamination problems and corrective action

Contamination	Liquid appearance	Detection testing	Corrective action	Suggested filter media	Comments
Water	Clear to milky white	Dielectric strength or modified Karl-Fisher titration, preferably with automatic titrator	Vacuum degasification	—	Free water should be siphoned, decanted or drained before processing the fluid
			Filter press	Paper or absorbent, e.g., diatomaceous earth	
			Cartridge filter	Absorbent cartridges	
Particulates	Clear with visible particles, hazy	Dielectric strength	Cartridge filter or filter press	None or diatomaceous earth as filter aid	
Mineral oil	Clear or two-phase, mineral oil odor	Flash and fire point or specialized testing	None	None	No economical methods exist for removing mineral oil from silicone fluid

6.2.1 Contamination with Water

In most practical applications involving the handling of transformer fluids, the rate of water absorption and dissipation is very important. In practice, however, the determination of moisture pick-up rates is very difficult since the rate is dependent upon the equipment configuration. The size, shape, and area of contact between the fluid and its environment affects the rate at which the fluid approaches its equilibrium water content. In certain test configurations, the rate of water absorption of silicone transformer fluid was similar to askarel.

When opening a transformer in a humid-air environment, exposure time should be limited to minimize transport of water vapor into the fluid. The same guidelines that have been established for askarel-filled transformers are recommended.

Within most fluid-filled transformer configurations there is an extremely large solid-to-liquid interface. The cellulose-based materials commonly used as transformer insulation are very hygroscopic and can absorb almost as much water as silica gel. Any water dissolved in the insulation system will reach a steady-state equilibrium with the transformer fluid, with most of the water remaining in the insulation. Thus, dry cellulose immersed in wet transformer fluid will dehydrate the fluid, with most of the moisture absorbed by the cellulose. The reverse process is also true in that dry fluid will absorb water from wet cellulose insulation. Evaluating the water content of the system based on a single measurement of the fluid water content may be meaningless.

Silicone fluids behave similarly to mineral oils and askarels with respect to transport of moisture into the transformer insulation. However, the saturation and equilibrium condition of silicone

fluids with insulation may be quite different from the other fluids. It is often more meaningful to consider the steady-state water content of the system than the water content of the fluid alone.

Experience in processing and manufacture of silicone fluid and silicone-fluid-filled transformers has shown that water can be removed from silicone fluid using conventional vacuum-drying techniques. Large manufacturers of silicone-fluid-filled transformers use the same vacuum-temperature treatment of dry and fluid-saturated windings as those that have been established for mineral-oil-filled and askarel-filled transformers. Smaller manufacturers have found that oven drying the windings and applying vacuum to the tank after assembly will produce a transformer with excellent dielectric properties.

A procedure that applies a vacuum of 1 to 2 torr at 105°C for 18 to 24 hours can be used to accelerate the transport of moisture from the inner layers of the coil to the air interface and promote release of the moisture to the air. Higher temperatures may accelerate the drying time; however, the 105°C temperature minimizes thermal degradation of the cellulose and keeps the cost of the vacuum system relatively low. When repairing a winding that is already saturated, the drying period should be extended to 48 hours to compensate for the reduced diffusion and dissipation rates of the water. If field repairs are necessary and a vacuum system is not available, a 48-hour drying time is recommended.

Refer to Section 6.3, Filtration, for information on removing water from silicone transformer fluid using filtration. Refer to Section 5.6, Vacuum Degasification, for additional information on removing water by vacuum treatment.

Effect of Water Contamination—Figure 6-4 shows that water is soluble to some extent in all common transformer fluids. Silicone fluid has a higher saturation water content than either fresh askarel or mineral oil. This is significant because, as shown in Figures 6-5 and 6-6, some dielectric properties deteriorate rapidly in the presence of moisture. Despite its higher water content at saturation, silicone transformer fluid maintains good dielectric properties at much higher water levels than askarel or mineral oil.

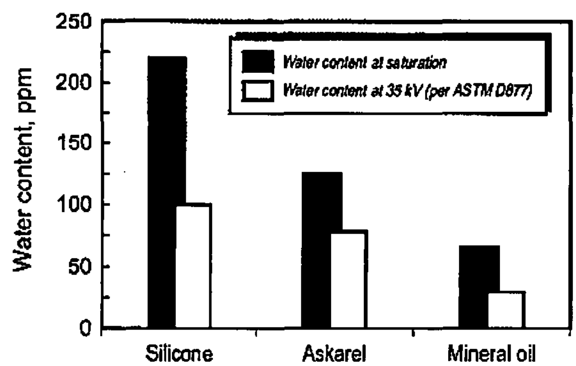


***Figure 6-4.** Solubility of water in various transformer fluids*

Dissipation factor and dielectric constant are not affected by the water content of the fluid alone. However, the dissipation factor of silicone-impregnated paper is affected by water. Volume resistivity will decrease linearly with water content in much the same way as dielectric breakdown. The relationship between volume resistivity and water content is shown in Figure 6-7. The partial discharge characteristics will also change with water content as shown in Figure 3-14.

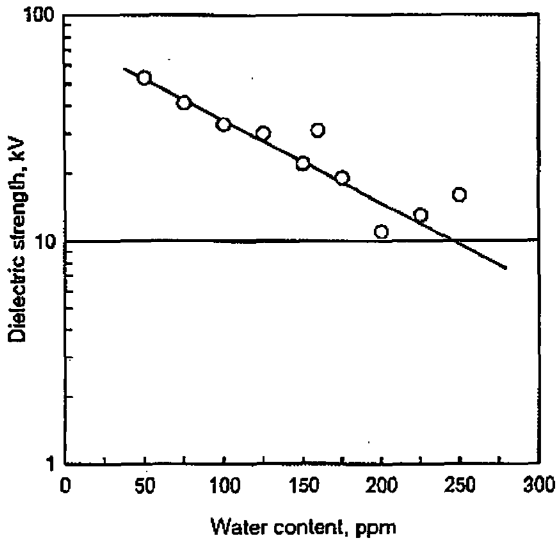


Figure 6-5. Decrease in dielectric strength with water content for Dow Corning® 561

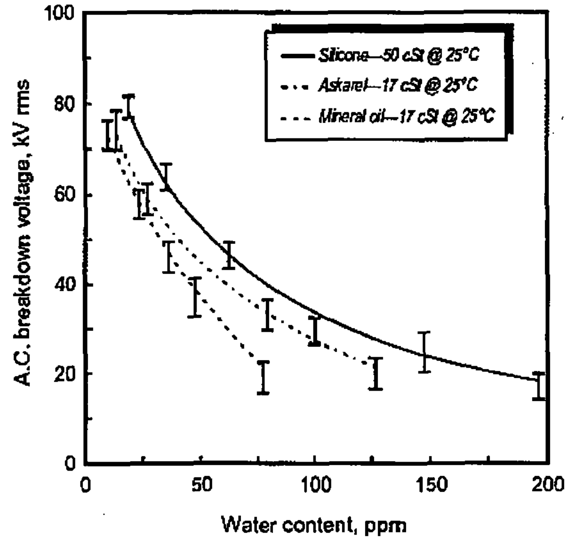


Figure 6-6. Breakdown voltage changes with water content for transformer fluids—12.5 mm diameter sphere-to-sphere electrodes with 2.5 mm gap

Rates of Water Pickup and Removal—Figure 6-8 shows the rate at which mineral oil and askarel pick up water when exposed to air of different humidities. In this work the fluids were exposed in a quiescent state under the following conditions:

Volume of fluid	7,500	cm^3
Surface area exposed	375	cm^2
Fluid depth	20	cm
Temperature	25	°C

Figure 6-8 shows that the sorptive ability of the fluid varies considerably. Askarel fluids pick up water more rapidly than mineral oil. A similar test on silicone transformer fluid (Figure 6-9) is also shown. The data cannot be compared directly to the mineral-oil and askarel data since the fluid volume is smaller and the surface area

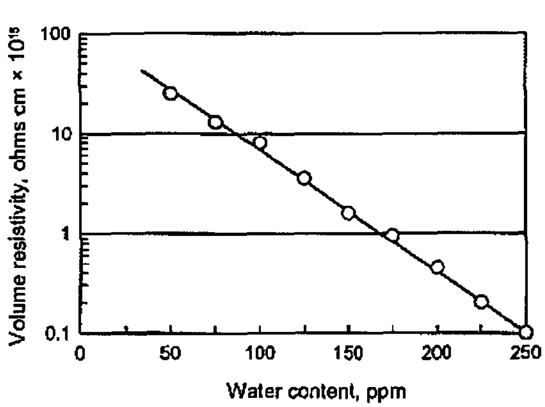


Figure 6-7. Relationship of volume resistivity of Dow Corning® 561 to water content (15-min stress data, Keithley 610R)

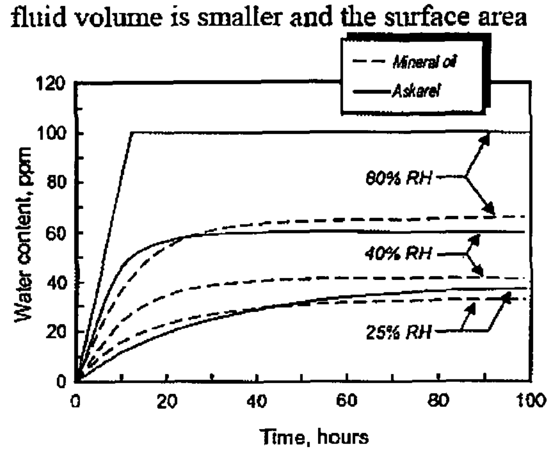


Figure 6-8. Rate of water absorption for transformer fluids at various relative humidities

to fluid depth ratio is much larger than in the tests above. The faster water pickup may be a result of these geometrical differences. However, if a linear relationship between sample dimensions and the time to reach equilibrium is assumed, the hygroscopic behavior of the silicone transformer fluid appears to be similar to askarel fluids.

Figure 6-9 also shows how rapidly water can be removed from the silicone fluid under mild drying conditions at 45°C. Experience with silicone transformer fluid during processing and manufacture has shown that silicone fluid can be dried to a low water content using either conventional or vacuum ovens. In the U.S., all large manufacturers of silicone-filled transformers use the same vacuum-temperature treatment of dry windings and fluid-saturated windings that has been established for mineral oil and askarel fluids. Practical work has suggested that drying of silicone fluid is best carried out in a conventional degasifier operating with vacuums of 1 to 2 torr and at temperatures between 20 and 80°C. Typical flow rates used in these degasifiers are 15 to 30 liters per minute.

The equilibrium moisture balance between humid air and *Dow Corning*® 561 Silicone Transformer Liquid depends on the humidity of the air and the water content of the fluid. Dry air will tend to dry wet fluid and wet air will add moisture to dry fluid. The rates at which this happens depend on such factors as surface area of fluid exposed to air, agitation, temperature, and the relative difference in the vapor pressures. A graph of the equilibrium water content of silicone transformer fluid at various relative humidities is shown in Figure 6-10.

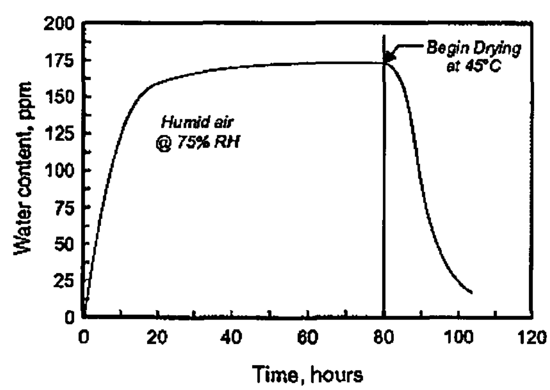


Figure 6-9. Water absorption and drying curves for Dow Corning® 561

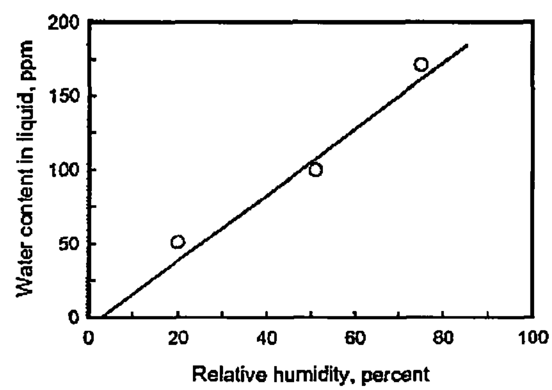


Figure 6-10. Equilibrium between moisture in air and water content of Dow Corning® 561

6.2.2 Contamination with Particulates

Refer to Section 6.3, Filtration, for removal of particulates.

6.2.3 Contamination with Mineral Oil

The solubility/miscibility of mineral oil in *Dow Corning*® 561 Silicone Transformer Liquid can vary with temperature and the feedstock composition and purification methods used to produce the mineral oil. Mineral-oil contamination will reduce the flash and fire points of *Dow Corning*® 561 Silicone Transformer Liquid (See Table 3-26). Refer to Section 6.5 for information and options for removing contaminants—including mineral oil—from silicone fluid.

6.3 Filtration

Silicone transformer fluids can be filtered to:

- Remove particulate (solid) contamination
- Reduce water content

6.3.1 *Removal of Particulates*

The type, amount, and size of the particles to be removed are important to the effectiveness of various methods of filtration. Three basic filtration devices are available: cartridge, filter press, and bag. The cartridge filter is usually the most effective and convenient. Cartridges have absolute filtration ratings. The rating, expressed in microns (micrometers, μm), is equivalent to the largest particle that can be passed. Absolute ratings of five microns or less will generally be sufficient to filter dielectric fluids for power transformers.

A limiting factor in the use of cartridge filters is the amount of particulate material that can be removed before the cartridges fill and begin to plug off. If large amounts of particulates are present, a filter press may be more effective. An example might be where adsorptive filter aids have been added to the dielectric fluid to aid in purification.

Bag filters can remove larger volumes of particulates. However, a 3-micron nominal rating for a bag filter, for example, compares more closely to a 15-micron absolute rating. Bag filters are more appropriate for crude filtration that is followed by a secondary filtration step with a finer filter element.

6.3.2 *Filtration to Reduce Water Content*

For a discussion on the effect of water on the properties of ***Dow Corning***® 561 Silicone Transformer Liquid, see Section 6.2, Contamination.

Water is largely insoluble in silicone transformer fluid. Free, or undissolved, water will separate from the fluid and settle to the bottom of the container. Silicone transformer fluid will appear milky white if contaminated with dispersed free water. The silicone fluid should not be used if this condition occurs. As much as possible of the dispersed free water should be removed by allowing the suspension to break and settle. Placing the container in a cool, dry area may facilitate this. Free water can then be removed by siphoning, draining from the bottom, or carefully decanting. However, the fluid must be further dried to remove any dissolved water.

It is difficult to remove large amounts of free water by filtration. Rapid wetting and saturation of the filter medium occurs, and excess water becomes dispersed in the fluid. However, trace amounts of dissolved water can often be removed with filtration techniques. This process is not true filtration; rather, the dissolved water is adsorbed onto the hydrophilic filter medium.

Dissolved water is not visible and must be detected by dielectric measurements or by other appropriate analytical techniques. (See Section 6.1, Periodic Inspection and Testing.)

A common approach to removal of water in transformer fluids is to use a blotter press. Care must be taken to properly dry any filter media to be used in the operation. Filter paper or cartridges should be dried immediately before use. For good results, spread the paper for maximum surface

exposure in a hot-air circulating oven for 4 to 6 hours at 110°C. Even better results can be obtained by drying the filter medium in a heated vacuum oven at 110°C for 4 to 6 hours.

An alternative to the filtration approach is to use a molecular-sieve bed to remove trace amounts of water. Molecular sieves can remove dissolved water from silicone fluid effectively and economically. Molecular sieves with a 10 to 13 Å pore size are recommended for water removal from silicone fluid. However, the most effective method of water removal is by vacuum degasification as described in Section 5.6.

6.3.3 Filtration Equipment

Table 6-5 is a list of companies that supply filtration equipment. It is strongly recommended that all apparatus used in sampling, filtering, storing, or transporting silicone transformer fluid be maintained for exclusive use with silicone fluid.

It is extremely difficult to remove all traces of hydrocarbon oil or other contaminants from equipment of this type. In addition, care must be taken to protect all such equipment from the elements and from water or moisture contamination.

Table 6-5. Filter equipment manufacturers

Manufacturer	Location	Telephone	Types of equipment
Filterite Div. of Memtec America	Timonium, MD	(410) 560-3000	Filter tubes and housings
Filter Specialists Inc.	Michigan City, IN	(800) 879-3307	Bag filters, pressure vessel filter housings
Sethco Division	Hauppauge, NY	(516) 435-0530	Cartridge filters
Pall Corporation	East Hills, NY	(800) THE-PALL	Cartridge filters, filter housings
Carborundum Corp.	Various in U.S.		Cartridge filters, filter housings
Shutte & Koerting	Bensalem, PA	(215) 639-0900	Cartridge filters, filter housings
Alsop Engineering Corp.	Kingston, NY	(914) 338-0466	Cartridge filters for the electrical industry
Filtration Systems Div.	St. Louis, MO	(800) 444-4720	Filter presses
AquaCare Systems, Inc.	Angola, NY	(716) 549-2500	Filter presses
Patterson Industries	Scarborough, ON	(800) 336-1110	Filter presses

This is not intended to be a complete list of filter-equipment suppliers. Not all equipment supplied by these companies may be suitable for **Dow Corning® 561 Silicone Transformer Liquid**. Consultation with the equipment manufacturer is recommended.

6.4 Leaks

Leaks may occur during the lifetime of a silicone-filled transformer. As part of any regular maintenance schedule, routine checks should be made to detect leaks. Areas to check and repair should include valves, bushings, gauges, tap changers, welds, sample ports, manhole covers, pipe fittings, pressure-relief valves, etc. In short, the entire surface of the tank and all devices connected to it should be inspected for leaks.

If the leak is at a gasket surface, the leak can be repaired by either installing new gaskets or, if the gasket is still serviceable, tightening down the burrs or bolts provided for that purpose.

If the leak does not involve a replaceable seal or simple retightening, welding and epoxy sealing kits are two commonly used techniques to repair the leak.

Silicone transformer fluid is an effective release agent; it prevents the formation of adhesive or cohesive bonds. As a result, most epoxy sealing kits used to patch mineral-oil or askarel leaks will not work on leaks involving silicone fluid. Proper surface preparation is difficult unless the silicone-fluid level is lowered below the leak. If the sealing kit is applied and fully cured before refilling the transformer to the normal fluid level, the seal will remain in place and stop the leak. Repair bonds formed before contacting silicone or bonds made on surfaces prepared in accordance with Section 5.8, Paint and Paintability, are unaffected when exposed to silicone fluid.

If leak repair requires reducing the fluid level, proper care must be taken to protect the purity of the silicone transformer fluid. Dedicated equipment and clean, dry storage containers must be used. Testing of the fluid is necessary before returning the transformer to its normal fluid level. All sampling, testing, and filling of transformers should be in strict accordance with the recommendations presented in this manual.

A more recent development is a sealing kit specifically designed for sealing leaks in silicone-filled transformers. For more information on this kit, contact:

Lake Chemical
250 North Washtenaw Ave.
Chicago, Illinois 60612

(312-826-1700)

Ask for information on Epoxy Tab Type S.

6.5 Reuse, Recycle, or Disposal of Silicone Transformer Fluid

Dow Corning's commitment to the environment is demonstrated by its willingness to assist customers in understanding options for handling used and/or contaminated ***Dow Corning®*** 561 Silicone Transformer Liquid. One of the strongest value points and least understood benefits of silicone fluid is the variety of options available to customers at end-of-use. Dow Corning firmly believes that waste minimization and reuse or recycle are much preferred alternatives to product disposal.

For transformer manufacturers, service companies, and large utility customers, waste minimization can take many forms. These include:

- Purchasing the proper quantity of material to reduce excess
- Minimizing the length of transfer piping that may require cleaning
- Reviewing systems to ensure secure storage, transfer, and usage
- Protecting equipment against physical damage

In 1996 Dow Corning established the ***Dow Corning®*** 561 Silicone Transformer Liquid Registration and Recycling Program as a multibenefit option for fluid nearing its end-of-use point or fluid contaminated with water, particulate matter, or mineral oil. The program is intended to reduce end-of-use handling concerns for prospective customers while at the same time providing 100% closed-loop life cycle for the fluid. Registration ensures that a transformer purchased today (or purchased in the past) containing ***Dow Corning®*** 561 Silicone Transformer Liquid will be a candidate for recycle consideration at end-of-use. More information on this program is available in a separate literature piece from Dow Corning (Literature No. 10-710-96).

6.5.1 Recycling

Recycling options include:

- Reusing the material in the same application
- Reprocessing of fluid contaminated with water, particulates, or mineral oil
- Special reprocessing of fluids contaminated with PCBs
- Fuel blending to recover energy

In some cases, fluid can be reused in the same application without reconditioning. ***Dow Corning®*** 561 Silicone Transformer Liquid can also be reprocessed to remove contaminants and then reused in transformers in many cases.

Commonwealth Edison, a major Illinois utility, has a reprocessing system in place specifically designed for recycling silicone transformer fluids. Commonwealth Edison specializes in fluids contaminated with water and/or particulates.

Silicone transformer fluid can also be reprocessed by the transformer owner or by a reputable service company. Reprocessing procedures are discussed in Sections 5.6 and 6.3 as well as in IEEE C57.111.

Dow Corning's Registration and Recycling Program is designed to accept fluids contaminated with water or particulates and that also meet certain other recycling criteria. Additionally, the

Dow Corning program can reprocess fluid that has been contaminated with mineral oil. This contamination may have resulted from several scenarios, but the most common one occurs when transformers originally filled with mineral oil are retrofilled with silicone fluid to improve fire safety and reduce long-term maintenance. Silicone fluid used to flush the mineral oil transformer is also a candidate for the Dow Corning program. Until this program began in 1996, the primary method for recycling this type of contaminated fluid was fuel blending or incineration.

Material returned to Dow Corning as part of the Registration and Recycling Program is returned one-way. Returned fluid is completely restructured through chemical reprocessing and then used to rebuild other specific silicone products. The Dow Corning program cannot, under any circumstances, accept fluid contaminated with PCBs.

SunOhio specializes in PCB-contaminated materials and is an option for those transformers that may contain PCB-contaminated fluids resulting from prior use of PCB fluids.

Fuel blending is another recycling alternative. Most non-PCB-contaminated silicone fluids are considered nonhazardous waste when disposed and can be compatibly blended with many organic solvents or other fuels. However, oxidizers and other incompatible materials as spelled out in the material safety data sheets should not be blended with silicones.

Silicones have two advantages when properly used in fuel-blending operations. Silicone fluids have a fuel value of approximately 8,000 Btu per pound, providing a favorable heat balance for fuel-use applications. Further, when silicone fluids are burned in silica-demanding processes such as cement kilns, the resulting silica becomes a valuable component of the product.

Silicone-containing materials should not be burned in internal combustion engines or other operations in which ash generation may interfere with the operation of the equipment. Always check equipment specifications and/or local regulations as appropriate prior to combusting silicone materials.

6.5.2 Incineration and Landfill

If other reuse and recycle methods have been thoroughly investigated, and destruction is the only remaining alternative, incineration of ***Dow Corning***® 561 Silicone Transformer Liquid can be considered. As with fuel blending and other combustion activities, incineration must consider the heat content of silicones and the silica ash generated by the combustion process.

Absorbents or other solid materials contaminated with ***Dow Corning***® 561 Silicone Transformer Liquid that might have been generated during maintenance or clean up of minor leaks or spills (assuming no PCB contamination is present) can be landfilled if local regulations allow.

6.5.3 Reprocessing and Disposal Services

Table 6-6 provides an overview of the alternatives and qualified reprocessors and disposal services. The lists on the following pages provide names, addresses, telephone numbers, and uniform resource locators (URL) on the World Wide Web for those companies. For further information on recycle or disposal of ***Dow Corning***® 561 Silicone Transformer Liquid or other Dow Corning silicone products, contact your Dow Corning representative, or call (800) HELP-561 (in Canada, call (416) 826-9600).

Table 6-6. Reuse, recycle, and disposal alternatives for ***Dow Corning***® 561 Silicone Transformer Liquid

	Fluid without PCB contamination				Fluid with PCB contamination	
	Used but not contaminated	Reprocessing to remove water or particulate contamination	Reprocessing to remove mineral oil contamination	Fuel blending	Reprocessing to remove PCB contamination	Services or incineration
Customer	✓					
Commonwealth Edison		✓				
S.D. Myers		✓				✓
Dow Corning		✓	✓			
Phillips Environmental				✓		
Systech Environmental				✓		
Safety-Kleen Corp.				✓		
SunOhio, Inc.					✓	
Incinerators						✓

Reprocessing of ***Dow Corning***® 561 Silicone Transformer Liquid contaminated with water and/or particulates (not PCBs) may be obtained from:

Commonwealth Edison
1319 South First Avenue
Maywood, IL 60153
(708) 410-5476

S.D. Myers
180 South Avenue
Tallmadge, OH 44278
(330) 630-7000
Web site: http://www.sdmyers.com

Dow Corning Corporation
Midland, Michigan 48686-0994
(800) HELP-561

Reprocessing of ***Dow Corning***® 561 Silicone Transformer Liquid contaminated with mineral oil is available through Dow Corning's Registration and Recycling Program:

Dow Corning Corporation
Midland, Michigan 48686-0994
(800) HELP-561

Reprocessing ***Dow Corning***® 561 Silicone Transformer Liquid contaminated with PCBs may be obtained from:

SunOhio
1515 Bank Place, S.W.
Canton, Ohio
(888) SUNOHIO
Web site: http://www.sunohio.com

Removal and disposal of ***Dow Corning***® 561 Silicone Transformer Liquid contaminated with PCBs is available from:

S.D. Myers
180 South Avenue
Tallmadge, OH 44278
(330) 630-7000
Web site: http://www.sdmyers.com

The following companies offer waste fuel-blending services for energy recovery:

Phillips Environmental
515 Lycaste
Detroit, MI 48214
(313) 824-5850

Systech Environmental
245 North Valley Road
Xenia, OH 45385-9354
(800) 333-8011

Safety-Kleen Corporation
1000 North Randall Road
Elgin, IL 60123
(800) 669-5740
Web site: http://www.safety-kleen.com/

6.6 IEEE Guide Availability

The comprehensive *IEEE Guide for Acceptance of Silicone Insulating Fluid and Its Maintenance in Transformers* (IEEE C57.111-1989) can be obtained by writing:

Institute of Electrical and Electronics Engineers, Inc.
345 East 47th Street
New York, NY 10017
U.S.A.

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Midland, Michigan 48686-0994

ATTACHMENT 5
Fire Protection Program Audit Frequency

Material/Documentation to support the current frequency of the audits based on the results of past audits.

Audit/ Assessment Number	Date	Comments	Quotes from Report on Frequency
SSA0101 Fire Protection and Loss Prevention Program	5/03/2001	Last annual Fleet Audit prior NQAP Frequency Revision	
SSA0201 Fire Protection and Loss Prevention.pdf	4/18/2002	SQN Only	Regulatory Guide 1.189, "Fire Protection for Operating Nuclear Power Plants," allowed TVAN to change annual audit intervals to a "maximum interval of 24 months" by implementation of a performance-based schedule justified by performance reviews) provided the maximum audit interval does not exceed the two-year interval specified in ANSI N18.7. NA reviewed all three sites' performance and concluded that BFN and WBN Fire Protection Programs indicate last year's performance justified going to an interval of 24 months and that this audit would be conducted for SQN.
SSA0301 Fire Protection and Loss Prevention Program Audit (Biennial/Triennial)	3/21/2003	WBN, SQN, BFN	This report documents the first Fire Protection audit performed since attributes of the annual, biennial, and triennial audit were combined into a single audit. The audit identified 1 significant audit issue at SQN and 46 other problems (9 at BFN, 15 at WBN, and 22 at SQN). These issues were entered into each site's Corrective Action Program.
SSA0501 - Fire Protection And Loss Prevention Program Audit (Biennial/Triennial)	6/01/2005	WBN, SQN, BFN	1) CORP PER 76142, Level C; The following problems were identified during preparation for the upcoming Fire Protection Program Audit, SSA0501. 1. The CY 2005 Fire Protection Audit was not started in time to meet the frequency required by the NQA Plan. 2. An evaluation of the fire protection program was not performed by NA in late 2003 as required by NADP-2, Audits. 3. Neither the NQA Plan nor NADP-2 identifies Regulatory Guide 1.189 as the commitment document for Fire Protection Audit frequencies.
NA-CH-06-003 Assessment Of Valley-Wide Fire Protection Performance	3/31/2006	WBN, SQN, BFN	There was satisfactory management oversight of system health performance which allows NA continued biennial frequency for audits. There was one recommendation for program enhancements for consideration
SSA0605 FIRE PROTECTION AND LOSS PREVENTION PROGRAM	4/ 27/2007	WBN, SQN, BFN	Dates of Audit were December 11, 2006 through March 21, 2007 Observation 41937 at WBN discussed the change in audit frequency, but this was not part of the formal report.

ATTACHMENT 5
Fire Protection Program Audit Frequency

Material/Documentation to support the current frequency of the audits based on the results of past audits.

Audit/ Assessment Number	Date	Comments	Quotes from Report on Frequency
NA-CH-07-004 - Nuclear Power Group (NPG) Fire Protection Program Performance Assessment	1/08/2008	WBN, SQN, BFN	The Fire Protection (FP) program assessment was performed to fulfill the requirement of NADP-2, Section 3.1.B.7, during periods between biennial program audits. Satisfactory performance against programmatic indicators allows NA to continue the biennial frequency for audits rather than increase the frequency to an annual audit based on declining performance.
SSA0808 Watts Bar Nuclear Plant - Fire Protection And Loss Prevention -Interim Report	1/027/2009	WBN	None
SSA0808 (NPG) Wide - Fire Protection And Loss Prevention Functional Area	2/20/2009	WBN, SQN, BFN	None
QA·CH·09·005·Nuclear Power Group (NPG) Fire Protection Program Performance Assessment	12/08/2009	WBN, SQN, BFN	The Fire Protection (FP) program assessment was performed to fulfill the requirement of NADP-2, Section 3.1.B.7, during periods between biennial program audits. Satisfactory performance against programmatic indicators allows Quality Assurance (QA) to continue the biennial frequency for audits rather than increase the frequency to an annual audit based on declining performance.
SSA1012 Watts Bar Nuclear Plant (WBN) - Fire Protection - Site Audit Report -	12/08/2010	WBN	None
2011 Annual Assessment is currently in progress		WBN, SQN, BFN	