Transformer Failure Analysis on Three Failures at Xcel Energy Substations – Chisago, Harrison & Fifth Street

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Introduction:

IEEE defines a transformer failure as “The termination of the ability of a transformer to perform its specific function” [1]. In the industry, we do what we can to prevent transformer failures. We assess their condition and repair transformers when impending failure is suspected. Some transformers fail with little to no warning while others we should see coming. Some failures are determined when a transformer is unfit for service by assessment, while others trip by protective relaying. Most all transformer failures have lessons to be learned if we are willing to heed the lessons. The transformer failures presented in this paper were catastrophic, of high interest, and have very good lessons to be learned.

Safety:

The transformer failures presented in this paper were catastrophic failures. Safety is the first concern. Substations are inherently dangerous places. No one should enter a substation that is not familiar with the dangers of a substation and standard safety precautions. The area in and around a failed transformer will have its own unique dangers which require appropriate training and equipment. Tag out procedures, energized equipment, hazardous materials, fall protection, and confined space are a few of the elements that will be encountered in an investigation.

Focus will be on the catastrophic failure, but attention must be forced to the surroundings. We all need to be safety observers with the responsibility and authority to stop work if we see unsafe practices. Some events may require the assignment of a full-time safety observer. It is important to know emergency phone numbers, where you are, and escape/rescue routes.

Investigation:

It is important to collect as much information as you can as soon as possible. Information will be lost as crews work on the transformer to test, repair and clean up.

IEEE C57.125 [1] is an excellent guide for transformer failure investigations. The IEEE guide is a 60-page document. Xcel Energy developed a three-page procedure following a transformer trip out which include many of the items in the IEEE guide for action immediately after a transformer trip. Our procedure is short and the steps are easy for operations to follow. Following are a few key items from the guide and additions that should be considered during a transformer failure investigation.

The transformer manufacturer will need to be informed if the transformer is under warranty. They will probably have their own procedures to follow. The transformer manufacturer will most likely take a least-cost option for them! Impacts on the system and cleanup due to their failed transformer are usually not covered in the warranty. The investigation and follow-on actions need to be a collaborative effort between original manufacturer and the end user if a warranty is involved.
An internal inspection is usually performed just to make sure there is not a problem that is field repairable. An internal inspection can be done with a camera probe or by draining and entering the transformer. Sometimes it is obvious the transformer is not field repairable. An internal inspection is an opportunity to get a first glance of damage in the transformer. Again, you want to get as much information as soon as you can, as some evidence may be lost during a teardown for rewind or during the scrap process. Manufacturer’s pre-tanking photographs should be reviewed prior to an internal inspection to allow familiarity of components and arrangements within the transformer. The inside of a transformer is a dangerous place, especially after a failure. Many of the internal supports and structures are compromised. Be very aware of your surroundings; it may be too dangerous to enter a failed transformer.

After immediate steps are taken and the transformer is declared not fit for further service, then a failure investigation can continue.

Data collected from the office files are important in a failure analysis. Tests (physical tests [2], oil quality [3], and dissolved gas analysis [4]) are usually performed on transformers. The test data is saved and comparisons are typically made with prior tests. Trending of data may give important insight to a failure. Trending is also important in lessons learned to prevent the next transformer from failing in a similar manner.

Reviewing the operations and maintenance history may give additional insight into a transformer failure.

Oscillographic records obtained from relays or fault recorders are valuable tools to determine how the failure and electrical fault progress. Oscillographic records are not always complete. It is still important to collect what you can for the analysis.

The teardown inspection:

The teardown inspection is the best opportunity to acquire physical evidence of the failure. The inspection is usually done in conjunction with a rewind teardown or the scrap dealer’s teardown. A scrap dealer’s teardown can occur in the field or in a shop. It is important to let everyone involved in the process (construction, scrap dealer, investment recovery, rewind shop, substation design engineering, …) know you are interested in a teardown inspection. Scrap dealers and rewind shops have a lot of experience in teardown inspections; take advantage of their experience. The investigative team needs to be on site when the teardown is conducted or they will move forward without you; their time is money! Take as many photos and samples as you can; this is your last chance to gather physical data.

Analysis:

Several stories (hypotheses) should be developed regarding the failure. Keep an open mind and discuss the information with peers. It is important to make sure the hypotheses are supported by the information collected. Eliminate hypotheses that cannot be supported by the data. Additional studies may be performed to test your hypotheses. The actual cause of a failure may never be known with 100% confidence. That’s OK! Do the best with what you have; make sure your confidence level is communicated in your reports.

Case Studies:

The information presented in this paper is not all-inclusive. Key information was pulled from transformer failure final reports and inserted in this paper for presentation.
**Fifth Street Substation:**
TR4 was removed from service by protective relays 30 October 2010 at 4:35 AM CST.

**Fifth Street TR4 Data:**
Manufacturer: Westinghouse
Date of Manufacture: Oct 1985
SN: MLM50651
Special ID: TRIS E0371, NX-27177, UTC - 0001673996
MVA: 75/84 FOW 55°C/65°C
No Load Taps: 107kV, 110kV, 113kV, 116kV, 119kV
Winding Design:
- Core Form
- 115kV Delta – 13.8kV Grounded Wye
- Reinhausen Type M: +/- 10% LTC on the 115kV winding

**Initial Inspection Findings:**
- The transformer tank was bulged on both the sides and the non-load tap changer (LTC) end (segments 1, 2 & 3). There was evidence of something within the transformer tank being pushed against the non-LTC end (segment 2).
- The force of the electrical fault had displaced the transformer about two inches to the north and east.
- The pressure release flag was up indicating that pressure was released from the transformer tank during the event.
- The pressure gauge showed +0.5 PSI (positive pressure).
- The liquid oil temperature gauge displayed approximately 22°C with the maximum temperature drag hand at approximately 34°C.
- The winding temperature gauge displayed approximately 23°C with the maximum temperature drag hand at approximately 38°C.
- The LTC position indicator was at the 1L position with the drag lead indication at 16R and 16L. The LTC operations counter reading was 063457.
- The No-Load Tap Changer (NLTC) was in position 3 (113kV).
- No oil had been spilled from the tank.
- There was no evidence of damage to bushings or arresters.

**Relay Targets:**
- 87T4 (differential) A, B & C phases
- 51H (overcurrent) B & C phases
- 63OI (sudden pressure)

**Oscillographic Record:**
The Aldrich Substation 115kV Fifth Street transmission line protective relay generated an event report and oscillographic record in response to this event. The electrical fault progressed to a full level B-C phase-to-phase fault within approximately one cycle following fault initiation. The fault further progressed to include ground approximately 1-3/4 cycles following fault initiation. The fault was fully isolated within 4-1/4 cycles. The event report contains no evidence of a through-fault prior to the event.

**Oil Analysis:**
Dissolved gas-in-oil analysis (DGA) was performed four days prior to the failure (64 days after being returned to service after the cooling system replacement). No gases were present that indicated a potential problem inside the transformer.
DGA analysis after the event revealed large amounts of acetylene, ethylene, ethane, methane and hydrogen. These gases indicate a fault had occurred within the transformer. Follow-up DGA for the LTC indicated gas levels were normal for this type of LTC.

Main tank oil quality (following the fault) showed acid number = 0.02 [mg KOH/g], IFT = 30.6 [dynes/cm], dielectric = 28 kV (1mm gap), Karl Fischer = 8ppm (10.9% relative water saturation at 27°C). All oil quality parameters were within IEEE C57.106 [2] suggested limits.

Transformer History:
TR4 was taken out of service for a cooling system replacement 4 December 2009. The oil was removed from the transformer 7 January 2010. A problem developed with the replacement coolers and TR4 was placed in storage with dry air until suitable replacement coolers could be acquired. New coolers were installed and the transformer oil filling process started 29 July 2010. TR4 was in dry air storage for approximately 203 days. Oil processing took more than five days during the filling process which is excessive; about three days of oil processing is normal. The transformer had a lot of moisture in it. TR4 was energized and load applied 23 August 2010 following the cooling system modification.

Loading:
A peak value of 53.73 MVA was recorded 23 August 2010 at 3:00 pm when TR4 was energized. The normal load seen by TR4 following the cooling system modification varied between 20MVA and 42MVA. The load was at a low level at the time of the fault; approximately 20 MVA as recorded by the energy management system (EMS) Fig 1. The new cooling system allowed the transformer to operate at a relatively low temperature. The temperature of TR4 was approximately 23°C (73.4°F) at the time of the failure. This transformer historically operated between 40°C and 60°C prior to the cooling system modification and it is designed to operate normally up to 95°C.

Fig 1. Transformer Loading Prior to the Failure

Tests After Trip:
Power factor, transformer turns ratio (TTR) and excitation tests were performed on TR4 following the event. The C-phase TTR ratio was off by almost 3%. The power factor tests also deviated by more than
an acceptable amount. The test sets did not trip out while testing, indicating that there are no shorted turns after the failure.

**Internal Inspection:**
The inspection team could not access the fault location directly because tolerances inside TR4 were very tight. Significant damage was found near the delta connection leads of the transformer, Fig 3. The LTC selector appeared to be in good condition, Fig 2. The NLTC switches / contacts appeared to be in good condition.

![Fig 2. Photos Taken During Internal Inspection](image)

**Teardown Inspection:**
A teardown inspection was conducted at Elliot Park substation 12 & 13 July 2011. The failure involved two high voltage leads associated with H2 and H3 at a lead support structure, Fig 3. The failure was at a location which would produce high electrical stress. The lead support was damaged by the force of the fault. The original manufacturer’s photograph is included for reference, Fig 4.

![Fig 3. Leads and Re-constructed Lead Support](image)
Pieces of the lead support at the location of the fault were collected; no signs of electrical stress were noted on the lead support structure. The lead insulation was unwrapped and analyzed for signs of electrical stress. No long term signs of electrical stress (treeing) were noted. A burned hole (or pit) was observed in the insulation near the location of the electrical fault on the H3 lead close to the conductor. This pit could be due to a void in the oil (bubble) or due to burning copper at the time of the fault.

**Analysis:**
It is believed the root cause of this failure was due to the extended dry storage of the transformer during the cooling system replacement. The transformer was stored dry for approximately 7 months. Oil processing took longer than normal due to the high moisture content in the transformer. Oil insulation contamination either by moisture or air resulted in an electrical breakdown of the insulation in an area of the transformer that was exposed to very high electrical stress. Moisture (due to ingress) or air (due to loss of oil impregnation) could be caused by an extended dry storage. There are many layers of paper in the leads which impair the ability of oil processing to remove moisture or re-impregnate the paper. This was a fast progressing problem; the dissolved gas in oil analysis four days prior to the event did not show signs of an evolving problem. This problem most likely started after the cooling system was replaced.

**Lessons Learned:**
- A transformer should be oil filled if it is expected to be idle for an extended period of time (greater than three months).
- Only one set of remote relays recorded this event and provided oscillographic records for analysis. Microprocessor based relays should be set to record events when any fault detection element picks up. This would allow better analysis of events.
- Static electrification was investigated as a possible cause due to the lower operating temperature with the new cooling system. Operating forced oil cooled transformer above 50°C will allow collected charge to dissipate faster and will reduce the chances of static electrification.
**Harrison Substation:**
Harrison transformer #1 was removed from service by protective relays 7 June 2010 at 6:29 pm MDT.

**Harrison TR1 Data:**
Manufacturer: Allis Chalmers  
Date of Manufacture: June 1971  
SN: 02-8226-52761-1  
Special ID: A41201  
MVA: 30/40/50/56 OA/FA/FA 55°C/65°C  
Core Form, 110kV Delta – 14.4kV Wye  
No Load Tap: A – 121kV

**Initial Inspection:**  
- Harrison TR1 high side tank wall was split open, Fig 5.  
- The side with the most apparent damage was associated with the #1 winding, below the H1 bushing.  
- Based on the location of items, it looked as if material from bushings, surge arresters, and the circuit switcher fell into the tank crushing the no-load-tap changer, leads, and supports.  
- Fire engulfed much of the substation destroying most of the distribution 13.8kV equipment and portions of the 115kV transmission equipment.  
- There was evidence of burning oil being sprayed over much of the substation yard, most in front of the 115kV side of the transformer in the direction of the tank rupture.  
- The ensuing fire destroyed support structures and possible evidence of the event.

![Fig 5. Photos of Failed Harrison Transformer #1](image)

**Relay Targets:**
The following targets were found:  
Harrison substation:  
* 1774 – A ph T, B ph T, C ph T  
* 1777 – A ph Inst, G Inst  
* 1778 – A ph Inst, G Inst  
* Electro-mechanical relay targets were not recently checked or cleared prior to this event; the feeder targets may or may not have been associated with this event.  
TR1 – 86T/51, 86T/87, 87 A Ph T & Inst, B ph Inst, C Ph T & Inst  
TR2 – 86T2/51  
115kV Bus differential A phase 87H, B phase 87H & 87L, C phase 87H
Oscillographic Records:
The only oscillographic record of the transformer failure was from a relay at Harrison on a line looking towards Cherokee, Fig 6. This is one of three sources feeding this electrical fault. No other line relays captured an event. CAPE modeled electrical fault studies indicate the Cherokee line would contribute about 20% of electrical fault current at Harrison Substation.

Oil Analysis:
This transformer had a long history of gassing, Fig 7. Oil samples for DGA in the main tank were taken more frequent beginning 2008 due to elevated levels of combustible gasses, carbon monoxide (CO), and hydrogen (H2), Fig 8.
TR1 Maintenance and Testing History:

- 6 Apr 2004: LTC Maintenance due to high gas levels and heating. The reversing switch had coking and a few stationary contacts had burning. The reversing switch was replaced along with the stationeries.
- 13 Apr 2005: A condition assessment was performed. The transformer was found to be in good condition.
- 24 Apr 2006: The LTC oil level was high, suspected the barrier board was leaking.
- 9 June 2006: The LTC oil level went from high 24 Apr 2006 to oil level gauge pegged high.
- 4 Dec 2006 – 14 Jan 2007: Replaced TLH LTC w/ Reinhausen RMV2. The series reactor was rewound to accommodate the new LTC. TR1 was energized 31 Jan 2007. The turns ratio after the replacement tested good.
- 27 Feb 2007: A condition assessment was performed. The second stage cooling was found not operating (repaired), the main tank was overfilled after LTC was installed, neutral current meter needed to be repaired, and the main tank was in a vacuum.
- 30 Jan 2008: A condition assessment was performed. The tank was under vacuum and power factor of the oil went up 4.5 times in 11 months. No other items were listed.
- 1 Oct 2009: A condition assessment was performed. The to linkage rod between LTC and LTC mechanism was loose. A low Myers index (IFT/Acid Number) and wet oil was found. The LTC linkage rod was tightened under a general work order.
- The transformer had experienced 15 electrical through faults within the year preceding this event. Data is not available on electrical fault current magnitude or duration.
- The transformer was originally purchased for and installed at Harrison substation. It has never been used in a different location.

Loading:
Transformer load at time of failure: 50.05MVA
Highest load since load tap changer (LTC) replacement (14 Jan 2007): 51.42MVA, 22 Jul 2008
Additional Load: HARR 1774 was carrying LEET 2495
LTC position at time of failure: 9R, drag hands at 2L & 9R
LTC limits of operation since LTC replacement (14 Jan 2007): 5L – 10R
Investigation:
It does not appear a low side (13.8kV) event initiated this transformer failure. The transformer #1 winding experienced the greatest damage due to electrical fault current and is associated with the 115kV A and C phases. The top ¼ of transformer #1 high voltage (HV) winding was expanded out. The top pressure plate associated with the winding was driven into the core of the transformer was very deformed, Fig 9. The transformer teardown revealed alternating distortion of the high voltage winding conductors just below the major expansion damage. This alternating distortion is evidence the failure started turn-to-turn of different conductors across two discs of the winding, Fig 10.

The oscillographic record supports a solid A phase to B phase electrical fault within 2 msec. Once the electrical fault involves the phase leads the current is no longer traveling through the windings, the windings will no longer experience electro-magnetic forces to distort them, Fig 11.
About 1-1/4 cycles into the phase to phase electrical fault, the electrical fault progressed to ground. There are multiple electrical burn marks on the transformer tank wall, internal barrier and bottom core yoke clamping assembly close to the location of winding 1. The visual evidence supported the oscillographic evidence.

Following is a likely progression sequence of the electrical fault as approximate time from inception of the electrical fault based on data available (oscillographic records and sequence of events):

<table>
<thead>
<tr>
<th>Time</th>
<th>Progression of Electrical fault</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 milliseconds</td>
<td>A turn-to-turn electrical fault started on the high voltage side of Harrison TR1, winding #1. (The high voltage winding 1 is electrically connected to A and C phase of the 115kV transmission system.)</td>
</tr>
<tr>
<td>2 milliseconds</td>
<td>The electrical fault progressed to a solid A phase to C phase electrical fault within the transformer.</td>
</tr>
<tr>
<td>20 milliseconds</td>
<td>The electrical fault progressed to a solid A phase to C phase to ground electrical fault arcing to the transformer tank wall within the transformer. This was probably due to expanding gases associated with the initial electrical fault and dielectric breakdown of the insulation in the transformer.</td>
</tr>
<tr>
<td>50 milliseconds</td>
<td>The transformer protective relay scheme sent a trip command to the TR1 115kV circuit switcher #9951. (note: the circuit switcher will attempt to open about 8 cycles later, approximate time in sequence to open 183 milliseconds)</td>
</tr>
<tr>
<td>92 milliseconds</td>
<td>The electrical fault progressed to include B phase, A phase to B phase to C phase to ground electrical fault. This progression is due to further expanding gases within the transformer associated with the existing electrical fault.</td>
</tr>
<tr>
<td>108 milliseconds</td>
<td>The transformer tank ruptured and oil was ignited. The tank rupture blew the top of the transformer off the main tank removing the current transformers from the 115kV bus differential scheme. This allowed the 115kV bus differential scheme to detect the electrical fault.</td>
</tr>
<tr>
<td>167 milliseconds</td>
<td>The 115kV bus / line breakers interrupted the electrical fault, tripped through the 115kV bus differential relay scheme. It took approximately 59 milliseconds for the 115kV bus differential relay to detect the electrical fault, send a trip command, and the 115kV breakers to interrupt the electrical fault. This 115kV bus differential detection and tripping time is not atypical for the 115kV bus protection equipment installed at Harrison Substation.</td>
</tr>
</tbody>
</table>

About two seconds later, the fire and gases likely caused an A phase to ground electrical fault on the line side of 9955. B phase to C phase electrical fault started at the same location just before the remote end (Leetsdale) interrupted the electrical fault. It appears an electrical fault also occurred on the line side of breaker 9956 which was interrupted by the remote end at Capital Hill Substation.

Transformer Analysis:
The original load tap changer (LTC) was a TLH. DGA of the LTC indicated problems within the LTC which lead to recent maintenance in 2002 and 2004. It appears the TLH LTC gases had stabilized at an acceptable level after the 2004 maintenance. The barrier board was discovered leaking April 2006. The TLH LTC was replaced with a Reinhauen vacuum LTC in the field January 2007. The transformer main tank was protected by a tarp for over a month while the preventative auto was being re-built to accommodate the new LTC. The field replacement of the load tap changer (December 2006) required the transformer to be opened for an extended period of time for workers to cut, splice, and weld.
The main tank oil was sampled nine months prior to this event and tested to have poor oil quality (high acidity, low interfacial tension, high moisture and low dielectric strength); this was noted on the transformer’s last condition assessment. The oil quality appeared to have degraded a large amount within six months. Replacement of the load tap changer may have allowed exposure to moisture and other contaminants in the transformer which could set in a location that would eventually result in a dielectric breakdown. The poor oil quality test indicates moisture might be the cause of the degraded oil quality. Poor oil quality could result in dielectric breakdown of the insulation in the transformer.

The electrical fault initiated at the highest load level served by TR1 in almost two years. The 50MVA load was within the nameplate rating of 56MVA. The oscillographic record of the Harrison – Cherokee 115kV line indicated a large amount of harmonic current distortion prior to the electrical fault. Tripplen harmonic (3rd, 6th, 9th, …) currents on the 13.8kV distribution side would not be detected on the 115kV side. High harmonics were detected at a customer’s site on one of this transformer’s feeders while investigating a power quality complaint. Harmonic currents through the transformer could result in additional loading/heating of the windings. Increased heating due to harmonics could have influenced initiation of the electrical fault during this high load period. No oscillographic records of the currents and voltages were obtained on the 13.8kV side of this transformer.

The teardown of the transformer revealed significant hoop buckling of the #3 low voltage winding, Fig 12. This winding was not involved in this electrical fault event, and the damage is not believed to be associated with the electrical fault. This is an example of damage due to accumulation of electrical through faults. This transformer experienced a large number of electrical through faults (15) within the year preceding this event. The transformer main tank dissolved gases were analyzed more frequently due to key combustible gases it was generating. Beginning in 2008 the hydrogen and carbon monoxide levels increased. These gases would indicate a partial discharge thermal problem involving paper. The damage to low voltage #3 winding may have been the source of this gassing first noticed May 2009.

Fig 12. Hoop Buckling of #3 Low Voltage Winding

Lessons Learned:
- Evidence of moisture contamination was detected in the transformer nine months before its failure through oil quality and moisture measurements. Appropriate follow-up should be done on items discovered during routine tests and assessments.
- The field replacement of the load tap changer (December 2006) required the transformer to be opened for an extended period of time for workers to cut, splice, and weld. All these activities could have potentially allowed contaminants to be introduced into the transformer. The transformer was 35 years old at the time of the LTC replacement and had a rough service life. A health assessment (including
age, history of loading, through electrical faults, and past maintenance) should be performed prior to a 
large, extensive LTC replacement project.

- The circuit switcher was not rated to interrupt the available electrical fault current at the 115kV level 
  experienced during this event. The current interrupting rating of the circuit switcher is 
inconsequential during this event because the circuit switcher was not fast enough to interrupt the 
electrical fault before the transformer tank ruptured. A transformer protection scheme designed to 
clear a 115 kV fault within 5 cycles of fault initiation might have prevented the tank rupture and fire.

- The transformer tank split at weld seams. Continuous support ribs surrounding the transformer may 
have provided additional strength to prevent the severity of the main tank rupture. Specifications 
should be reviewed to determine if the transformer tank strength can be improved.

- The oil containment was a berm encircling both transformers and the switchgear. This could allow 
burning oil spilling from the transformer to flow around the switchgear and transformer #2. Separate 
oil containment and a fire wall between the switchgear and transformers could potentially limit the 
spread of oil and flame and prevent extensive collateral damage to switchgear and other equipment.

- The fire department was spraying water over the wall into the substation within minutes of the fire 
starting. Water could spread the oil and fire; this coupled with the oil containment design potentially 
could have contributed to the extensive collateral damage experienced in this substation event. The 
fire department should be made aware of the hazards within electrical substations.

- Only one protective relay at the substation captured the event. This relay record was one of the 
critical elements in analyzing this event. Recording protective relays should be set to capture all 
events that pick up fault detector elements within the relay. This will allow a more complete picture 
of events and help validate CAPE models.
Chisago Substation:
TR6 was removed from service by protective relays 24 November 2007 at 10:30 AM CST.

Transformer Details:
Manufacturer: Federal Pacific Electric Co
Date of Manufacture: April 1980
Serial Number: 90017-1
Alias: TRIS - B0034
UTC Number: 0001673747
Transformer Type: Core Form, Three Phase Auto
Rating: OA/FOA/FOA   55°C//65°C   240/320/400//448MVA   Directed Flow

Initial Inspection Findings:
• The transformer tank was split open at the corner seams, Fig 13. The cooling piping was broken.
• Most of the 20,400 gallons of oil had spilled on the ground.
• No evidence of overheating or overloading was detected.

Oscillographic Record:
A fault recorder was installed at Chisago Substation and captured the event. The recorder was applied to the 345kV terminals and the tertiary current. No oscillographic records were available on the 115kV system, Fig 14. It appeared the fault started 345kV B phase to 115kV A phase then progressed to include
ground within ¼ cycle. The A phase current jumped up the last ½ cycle of the fault. The electrical fault was cleared 3-1/2 cycles after it started.

![Chisago TR6 Failure](image)

**Oil Analysis:**
Dissolved gas-in-oil analysis (DGA) was performed about 10 months prior to the failure. The DGA appeared normal with no significant changes in gases noted.

**Transformer History:**
Apr 1980 Originally installed at Coon Creek TR10
Jan 1993 Bushing X1 failed, GE type U, X1 bushing replaced w/ Westinghouse type O+
Apr 1996 Installed at Chisago TR6, H1 bushing replaced, all X bushings replaced.
Apr 2003 Condition Assessment Performed, Initially rated pending due to low oil dielectric - dielectric resampled at 28kV, Coded 4, DP (by furan) >1000

**Loading:**
There were no records of the transformer being loaded above nameplate. Recent records indicate maximum load within last 2-1/2 years was 183MVA. Load at the time of failure was about 72MVA.

**System Conditions:**
The system voltage at Chisago was in alarm at 362.7kV; the alarm point is 362kV. No other switching was being done nor did any other event occur on the system at the time of the failure.
Investigation:
The 345kV leads connect to the middle of the series (HV) coils. The 115kV leads are on both ends of the series coil, Fig 15. Insulating barrier boards were wrapped around each phase for the directed flow and insulating barrier boards were placed between the phases for additional phase-to-phase insulation, Fig 16. The 115kV to ground, common (LV) coils are nested inside the series (HV) coils. The electrical fault started 345kV B-phase to 115kV A-phase across the insulating barrier boards, then progressed to include ground about ¼ cycle after the electrical fault initiated.

The electrical fault was cleared within 3-1/2 cycles. The tank ruptured due to the energy fed into the failure.

A report of a study performed by Manitoba Hydro in 2003 surfaced shortly after the failure. The study was conducted associated with 115kV capacitor bank installations at Chisago Substation. The study indicated this transformer would be subject to high phase-to-phase transients. Interestingly the transformer failure appears to have started with a phase-to-phase electrical fault.

Lessons Learned:
- The oscillographic fault record was instrumental in determining the sequence of the electrical fault which helped the analysis. Relays should be set to record oscillographic information when events occur to aid in the analysis.
- The transformer tank split open. The tank welds were on the corner seams with no additional support. Reinforced seams and welds placed in locations that provide more strength may prevent tank ruptures.
- The protection appeared to operate correctly. Fast clearing of the electrical fault is believed to have prevented a fire from starting with this failure.
References: