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3D in Substation Design

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Not Available for Publication

A Case Study of the Geomagnetic Induced Current (GIC) Level from the Neighboring System

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1.0 ABSTRACT

During a Geomagnetic Disturbance (GMD) event, Geomagnetic Induced Current (GIC) will enter into the transmission system through the ground wire of the Wye-grounded transformer. Since the GICs will occur across the utilities, including the GICs entering from the neighboring system is necessary in the analysis. The size of the neighboring system (boundary of the neighboring system) included in the study model may change the GIC level in the study area significantly. A case study was performed to evaluate the GIC levels from the neighboring system by changing the size of the neighboring system included in the study model. The study cases were developed with the different sizes of the neighboring system with a study utility (Lubbock Power & Light) and its neighboring system data. GIC module of Siemens PTI's Power System Simulator for Engineers (PSS®E) software was used in the analysis. This paper discusses the observed GIC levels coming into a study utility and its correlation to the size of the neighboring system included in the model. The modeling portion of this case study satisfied Requirement R2 of the NERC TPL-007-1 standard.

2.0 INTRODUCTION

2.1 Background

When corona mass ejections out of the Sun come towards the Earth, a Geomagnetic Disturbance (GMD) event occurs on the Earth. Rapidly changing electromagnetic fields over large regions on the Earth induce voltage potentials on the Earth's surface. Different voltage potentials on the ground level induce Geomagnetically Induced Current (GIC) and will enter into the transmission system through the ground wire of a Wye-grounded transformer. The GIC in the transmission system can have a wide impact from transformer loading to system harmonics interference [1][2].

Federal Energy Regulatory Commission (FERC) directed North American Electric Reliability Corporation (NERC) to develop a reliability standard that addresses the impact of GMD on the bulk electric system under FERC Order No.779. (Reliability Standards for Geomagnetic Disturbances) [3]. NERC issued a draft transmission planning standard TPL-007-1, "Transmission System Planned Performance During Geomagnetic Disturbances" as a response to the FERC Order No.779. The draft standard passed the final ballot and NERC filed a petition seeking FERC approval on January 21, 2015 [4]. The NERC TPL-007-1 standard includes seven different requirements that Transmission Planners or Planning Coordinators must meet at different deadlines. Since GIC is quasi-DC current, one of the requirements involves developing and maintaining DC equivalent models of the system to effectively study GIC impact.

2.2 Problem Description

This technical paper discusses one important modeling issue, the impact of the neighboring system, which Transmission Planners or Planning Coordinators may encounter as they develop their equivalent DC model. While it is not clear how much of the neighboring system has to be included in the equivalent DC model for compliance with the NERC TPL-007-1 standard, the impact of the neighboring system on the GIC level is significant. The impact of the neighboring system was investigated through a case study utilizing information from Lubbock Power and Light (LP&L)'s 230 kV transmission system and assumed data on their neighboring system. This paper also discusses different considerations when determining the boundary of the neighboring system. The GIC module of Siemens PTI's Power System Simulator for Engineers (PSS®E) software was used to perform the analysis in the case study.

3.0 STUDY ASSUMPTIONS

The study was completed using the GIC Module in PSS®E version 34. System data specific to the LP&L system was provided by LP&L. The pertinent considerations in the development of the study models are summarized below.

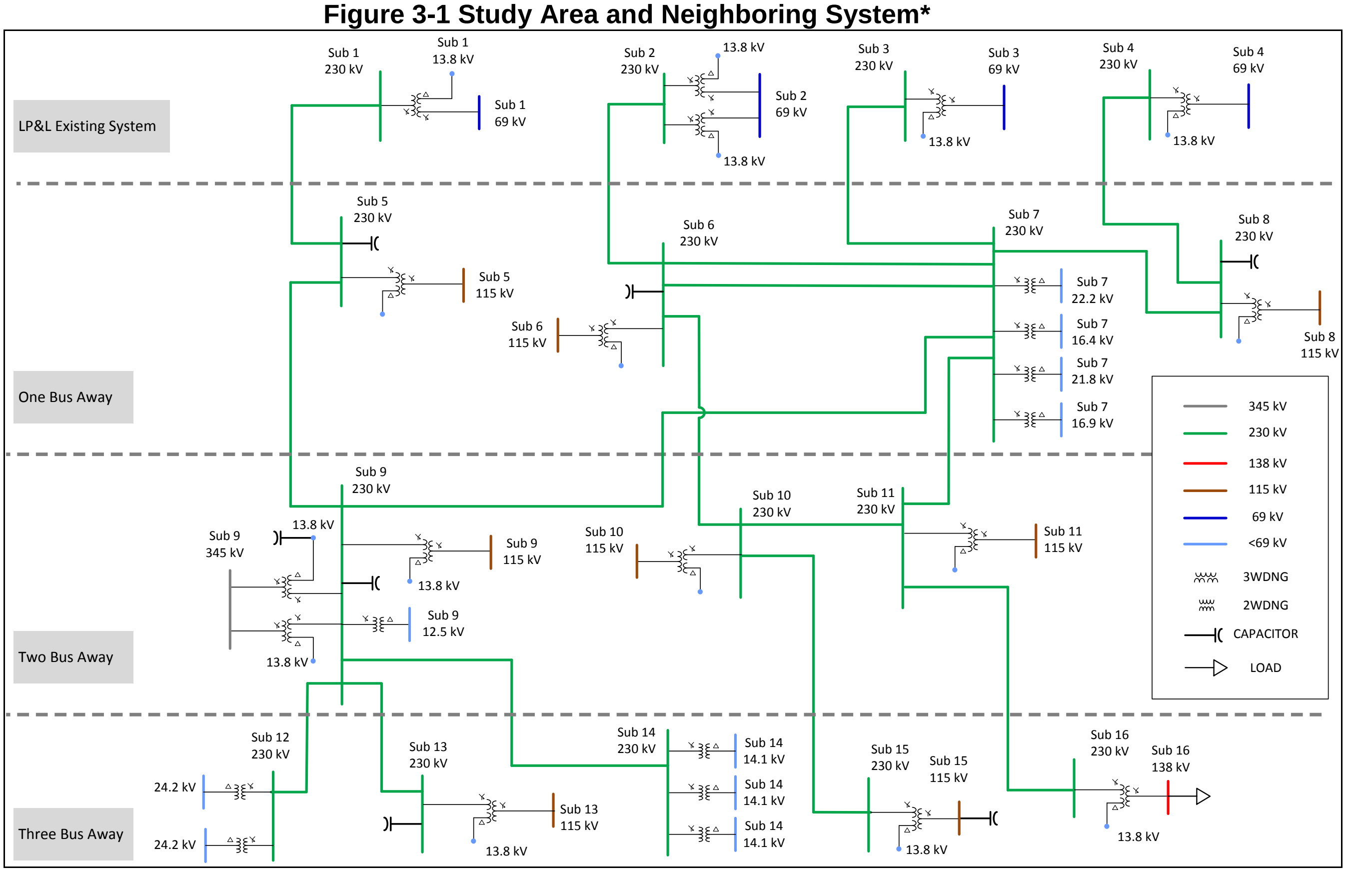
3.1 Neighboring System

Collecting the necessary information required to develop an equivalent DC model for the area outside a utility's system can be challenging. Thus, a discussion about how to set the neighboring system boundary pertains to the issue of accuracy but also to the issue of availability and efficiency. The NERC Application Guide for Computing Geomagnetically-Induced Current in the Bulk- Power System [5] describes three different options to model the neighboring system:

1. Leave the neighboring system connection as an open circuit and only develop the utility's own system.
2. Represent the neighboring system as a line to the first substation of the neighboring system and its resistance to ground.
3. Represent the neighboring system as a very long line. The resistance of the first line and the induced voltage are included in the model, but not the resistance to ground.

PSS®E GIC Module provides a way of including the neighboring system into the GIC calculation. The user can assign Intertie Levels to include specified neighboring system levels. However, at the edges of the Intertie Level, an open circuit is assumed and ignored in GIC calculation. In the case study, the Intertie Level was varied from 1 to 3 and the GIC was evaluated within the study area. The study area and neighboring configuration used in the case study is shown in Figure 3-1. The diagram does not reflect substation geographical information but rather is arranged with respect to their Intertie Level.

Figure 3-1 Study Area and Neighboring System*



* The diagram only includes details of the 200 kV and above network.

3.2 Transformer Configuration

In typical load flow modeling, transformer configurations are often not completely captured and the data within the load flow models do not reflect actual configurations, however, in equivalent DC modeling the configuration of the transformers is of utmost importance. There are two reasons for this. The first reason is that the transformers in the system provide most of the physical connections to Earth (grounding). This physical connection to Earth provides the path for GIC to travel from the Earth into the electrical system. Shunt devices also provide such a ground path but are far fewer in number. Furthermore, the configuration of the transformer ground connection is important. If the transformer has a delta connection and it does not have a ground path from the transformer to the ground, then there is no path for the GIC to enter the system. GIC only enters the system through Wye-grounded connections. This concept is codified within the NERC TPL-007-1 standard in that it requires developing equivalent DC models for transformers higher than 200 kV voltage on its high side with Wye-grounded connections [4]. The GIC coming through the below 200 kV system has a comparatively smaller impact on the 200 kV and above system because of the relatively higher impedance associated with the transmission lines on the lower voltage system. The second reason transformer configurations are important is that the configurations can produce different heating effects within the transformers.

The transformer configuration parameters in the PSS®E load flow case in the study area was updated to match the transformer data listed in the transformer test data provided by LP&L. The configuration in the PSS®E load flow case for the neighboring system transformers was assumed to be correct and the vector code associated with this configuration was applied and saved in the study case.

3.3 Transformer Data

The transformer DC resistance values and configurations for the study area and Intertie Levels used within this case study are discussed in this section. There are 5 transformers with high sides greater than 200 kV within LP&L's selected study area. Some of the transformer parameters are shown in Table 3-1.

Table 3-1: Study Area Transformer Data

Transformer	Configuration	3 phase Winding Resistance (Ohms/phase)		Converted DC Resistance (Ohms/phase)	
		Series	Common	Series	Common
1	3 winding, grounded wye, auto	0.3884	0.0473	0.1295	0.0158
2	3 winding, grounded wye, auto	0.5444	0.1889	0.1815	0.0630
3	3 winding, grounded wye, auto	0.5444	0.1889	0.1815	0.0630
4	3 winding, grounded wye, auto	0.3872	0.0471	0.1291	0.0157
5	3 winding, grounded wye, auto	0.3884	0.0473	0.1295	0.0158

As described in the NERC Application Guide for Computing Geomagnetically-Induced Current in the Bulk- Power System [5] (GIC Application Guide), the best source for transformer information is the transformer test reports. Test reports for the study area were analyzed and the values for winding resistance at the reference temperature (75 degrees) for each winding were found. This value was converted from the three phase value to the DC resistance value in the manner described in Table 2 of the GIC Application Guide.

Intertie Level 0 is defined as the study area. Intertie levels are defined by the number of buses away from the study area. The Level 1 intertie represents 1 bus away from the study area. In this study, Intertie Level 1 includes 4 substations and 7 transformers in addition to the network modeled explicitly in Level 0. The data for the additional transformers is presented in Table 3-2.

Table 3-2: Intertie Level 1 Transformer Data

Transformer	Configuration	Converted DC Resistance		Unit
		Series	Common	
5	3 winding, wye grounded	0.5870	0.1470	Ohm/Phase
6	3 winding, wye grounded	0.2330	0.0580	Ohm/Phase
7	2 winding, wye grounded	0.1815	0.0630	Ohm/Phase
8	2 winding, wye grounded	-	0.2700	Ohm/Phase
9	2 winding, wye grounded	-	0.2430	Ohm/Phase
10	2 winding, wye grounded	-	0.2670	Ohm/Phase
11	3 winding, wye grounded	0.2330	0.0580	Ohm/Phase

Intertie Level 2 represents 2 buses away from the study area. In this study, Intertie Level 2 includes 3 substations and 7 transformers in addition to the network modeled explicitly in Level 1 for a total of 11 substations. Table 3-3 presents the additional transformer data for Level 2 substations.

Table 3-3: Intertie Level 2 Transformer Data

Transformer	Configuration	Converted DC Resistance (Ohms/Phase)	
		Series	Common
12	2 winding, wye grounded	-	0.5770
13	3 winding, wye grounded	0.2300	0.0580
14	3 winding, wye grounded	0.2490	0.0620
15	3 winding, wye grounded	0.1520	0.0670
16	3 winding, wye grounded	0.1470	0.0650
17	3 winding, wye grounded	0.4730	0.1180
18	3 winding, wye grounded	0.4810	0.1200

Intertie Level 3 represents 3 buses away from the study area. This Intertie Level adds 5 substations and 8 transformers in addition to the network modeled explicitly in Level 2 for a total of 16 substations. Table 3-4 presents transformer data for the additional transformers at these substations.

Table 3-4: Intertie Level 3 Transformer Data

Transformer	Configuration	Converted DC Resistance (Ohms/phase)	
		Series	Common
19	3 winding, wye grounded	0.4810	0.1200
20	2 winding, wye grounded	0.0640	0.0010
21	2 winding, wye grounded	0.0660	0.0010
22	2 winding, wye grounded	0.4420	0.0020
23	2 winding, wye grounded	0.4420	0.0020
24	2 winding, wye grounded	0.4420	0.0020
25	3 winding, wye grounded	0.6430	0.1690
26	3 winding, wye grounded	0.4070	0.1470

3.4 Substation Grounding Grid Resistance and Earth Model

Substation grounding DC resistance in Ohms is necessary for the GIC calculation. Test data on the grounding resistance of the Level 0 substations was not available at the time of the study, so a value was calculated using design modeling. This is the best alternative as outlined in the GIC Application Guide. For the grounding resistance calculation, a soil resistivity assumption of 60 Ohm-m was used. The ground grid depth assumed for all Level 0 sites was 18". Where ground grid drawings were available, the grounding information from the drawing was used. For substations without clear information from the ground grid drawings, a 20' mesh grid with 2/0, 7 strand copper conductor was assumed. Also, the geographical location of the substations was used for the earth model of the area. IP4 represents the Interior Plains (Great Plains) physiographic region of the US. Table 3-5 provides a summary of the study area substation information.

Table 3-5 Substation Ground Grid Information

Substation	Grounding Resistance	Earth Model
1	0.257	IP4
2	0.177	IP4
3	0.151	IP4
4	0.254	IP4

Information on grounding resistance for non-Level 0 substations was not available for this study. In this case, the lowest ground grid value found in the Level 0 substations was used as the assumed grounding resistance for all non-Level 0 substations. This assumption was used because the lower ground grid resistance creates a worst case scenario by decreasing the overall resistance in the equivalent GIC DC circuit. For all substations outside the explicitly modeled levels, the assumed substation grounding DC resistance was 0.1 ohm.

4.0 GIC CALCULATION STUDY

The study was performed with GIC Module in PSS®E version 34 for different Intertie Levels. Since the orientation of the GMD event created different GIC levels within the system, GMD orientation was fixed at 90 degrees for the simulation while Intertie Levels were varied from Level 0 to Level 3.

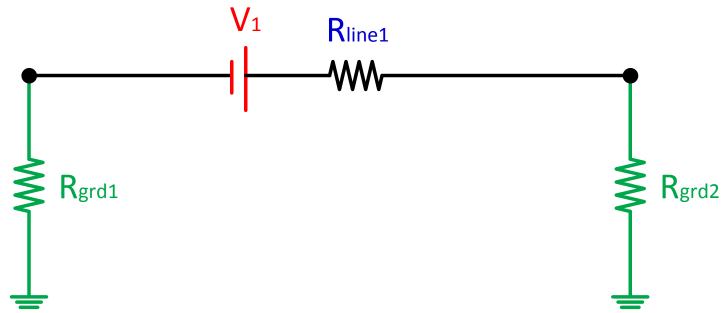
4.1 GIC Calculation Results

GIC calculation results are presented by Intertie Level in the following sections.

4.1.1 Analysis with Intertie Level 0

There were 4 ground connections on the high side of the transformers but there were no transmission lines between substations in the study area. The 4 ground connections would provide a path for GIC to flow if the high side non-transformer connections existed. PSS®E GIC Module uses the GIC calculation method that applies induced voltage on the transmission line. This is the latest recommended methodology by NERC [6]. The illustration of the GIC calculation method is shown in Figure 4-1. Since there is no transmission line within the case study Level 0, GIC cannot be calculated.

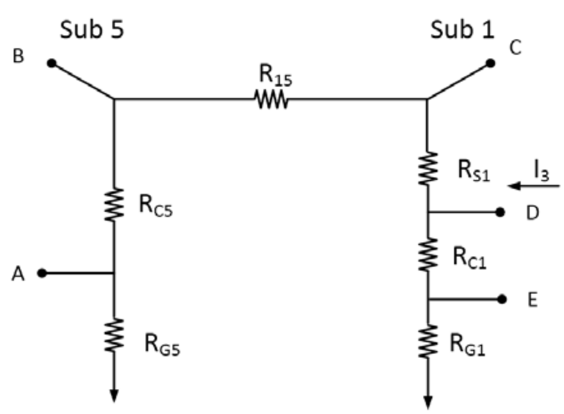
Figure 4-1 GIC Calculation Illustration



4.1.2 Analysis with Intertie Level 1

Intertie Level 1 model included 4 additional substations, 4 of 230 kV transmission lines and 8 new grounding connections on the high side of transformers. To illustrate the results of the GIC calculations, one DC circuit created with the additional Level 1 substations is isolated in this section. It is important to do this isolation now because as Intertie Levels increase the resultant DC circuits will become more interconnected and complex. This will make nodal analysis much more difficult. Figure 4-2 shows the DC circuit created from the addition of the Level 1 intertie for Sub 1.

Figure 4-2 DC Circuit Representation of Sub 1 for GIC Calculations



Sub 1 is in the Level 0 study area while Sub 5 is in Intertie Level 1. There were two connections to ground on the high side of the transformers in this circuit. The two substations were connected on the high side with a transmission line. The high side winding of the 3 winding wye-grounded transformer in

Sub 5 and the common and series winding of the 3 winding auto transformer in Sub 1 complete the DC circuit. The substation grounding resistances were also modeled in the DC circuit. All voltages, currents, and resistances in Figure 4-2 are presented in Table 4-1.

Table 4-1 Intertie Level 1 Voltages, Currents, and Resistances

Node	DC V	Branch	Current (A)	Element	R (Ohms/Phase)
A	0.06429	A-B	0.14192	G1	0.257
B	0.14763	B-C	0.14192	C1	0.016
C	-0.12983	C-D	0.14192	S1	0.130
D	-0.11138	D-E	0.14192	12	0.159
E	-0.10921	E-G1	0.14192	G2	0.151
				C2	0.587

In Table 4-2, it shows that current in the common winding is the same as the current in the series winding. The current is the same because the Intertie Level 1 did not include low voltage transmission lines (69 kV line) and the current I_3 in Figure 4-2 is 0. This is the case for Intertie Level 1, but it will not be the case in further Intertie Levels as the study area grows for Sub 1. However, for Sub 2, Sub 3 and Sub 4, Intertie Level 1 includes the low voltage transmission lines connecting one another, the current flows through the low voltage transmission lines and the flow through the common winding and series winding are not same. The GIC values for the transformers for Sub 1, Sub 2, Sub 3 and Sub 4 are shown in Table 4-2.

Table 4-2 Intertie Level 1 Study Area Winding Currents

Substation	Common Winding GIC (A)	Series Winding GIC (A)
1	-0.14192	0.14192
2	1.3809	-0.58657
3	-1.50725	0.39824
4	-0.35733	-0.12231

The table shows that the GIC for the common winding and series winding for Sub 1 are the same while for the other substations they are different.

Another important observation in Table 4-1 is that the currents in branch A-B equal those of branches B-C, C-D and D-E. This is because GIC can only go through the DC path shown in Table 4-2. There are no other connections for the current to go through. The Intertie Level 1 for Sub 1 shows a radial network characteristic. The magnitude of the GIC is dependent on two transformers and one transmission line.

The rest of the substations (Sub 2, Sub 3 and Sub 4) have DC circuits connecting one another. Thus, all of these substations in Intertie Level 1 model already have a meshed network characteristic. The magnitude of the GIC is calculated out of all the transformers and transmission lines (both high voltage and low voltage). Since it was calculated all together (Sub 2, Sub3, Sub 4, Sub 6 and Sub 7), the summation of all substation GICs on the high side show 0. The GIC for all the substations is summarized in Table 4-3.

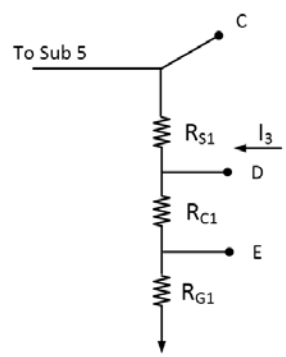
Table 4-3 Intertie Level 1 Substation GIC

Substation	Current (A)
2	8.28538
3	-4.52174
4	-1.07200
6	-0.45293
7	0.00000
8	-2.23869

4.1.3 Analysis with Intertie Level 2

The addition of Intertie Level 2 results in a total of 11 substations and 16 high side ground connections. At this level the DC circuit is meshed for all substations and includes all ground connections. Figure 4-3 focuses on the connection to ground at substation 1.

Figure 4-3 Substation 1 Grounding Connection Diagram



The currents in the study area transformer windings are presented in Table 4-4.

Table 4-4 Intertie Level 2 Study Area Winding Currents

Substation	Common Winding Current (A)	Series Winding Current (A)
1	5.12754	2.93729
2	2.94748	0.76033
3	0.81456	0.85368
4	0.88801	0.94328

Because of the additional connections in Intertie Level 2, I_3 is no longer 0, therefore the currents in the series and common windings at Sub 1 are no longer equal. Effective GIC is a function of all three currents, so the addition of Intertie Level 2 will subsequently affect the resulting effective GIC at Sub 1.

To analyze Intertie Level 2 as a whole we can look at the substation GIC through the grounding connections. These currents are presented in Table 4-5.

Table 4-5 Intertie Level 2 Substation GIC

Substation	GIC (A)	Substation	GIC (A)	Substation	GIC (A)
1	-2.93729	5	3.34559	5	3.34559
2	-0.76033	6	0.46452	6	0.46452
2	-0.76033	7	0.56268	7	0.56268
3	-0.85368	9	0.01834	9	0.01834
4	-0.94328	9	0.01698	9	0.01698

It can be seen in Table 4-5 that the currents in the study area (Sub 1 through Sub 4) have increased. One might conclude that a pattern is developing but this is not necessarily the case. The current values will be determined by the resulting DC circuit. As Intertie Levels change so does the DC circuit configuration. This may result in an increase or a decrease in current values. The sum of the GICs for all substations is 0.

4.1.4 Analysis with Intertie Level 3

The addition of Intertie Level 3 results in a total of 16 substations with a total of 20 high side transformer ground connections. All the connections are meshed into one DC circuit. The currents through the transformers in the study area are presented in Table 4-6.

Table 4-6 Intertie Level 3 Study Area Winding Currents

Substation	Common Winding Current (A)	Series Winding Current (A)
1	4.49339	-0.65357
2	1.95853	0.30678
3	-1.05275	0.37706
4	-0.12717	0.19074

With the addition of Intertie Level 3 a new DC circuit is created such that the current levels in the common and series windings have decreased. Also notable is that the common and series winding current values are not the same as was seen in the results in Intertie Level 2. The currents for all the high side ground connections in Intertie Level 3 are presented in Table 4-7.

Table 4-7 Intertie Level 3 Substation GIC

Substation	GIC (A)	Substation	GIC (A)	Substation	GIC (A)	Substation	GIC (A)
1	0.65357	5	-0.35135	9	0.11946	11	-2.15599
2	-0.30678	6	-0.69464	9	0.1233	12	-0.28151
2	-0.30678	7	-0.24537	9	0.00125	15	3.92974
3	-0.37706	9	0.03499	9	0.01396	16	-1.47013
4	-0.19074	9	0.03239	10	1.47168		

Comparing the current values in Table 4-7 to those in Table 4-5, it can be seen that some values have increased, some have decreased and some have switched direction altogether. This is because the equivalent DC circuit changes as the equivalent DC model grows and because newer loops can be created by the increased equivalent DC model.

4.2 Effects of Intertie Levels on GIC Values

The impact of Intertie Levels (neighboring substations) on the substation GIC values was analyzed. Since the effective GIC value is dependent on the transformer's own characteristics, the substation GIC flow was used for the Intertie Level impact comparison. The GMD event angle was changed from 0 to 360 degree and the GIC through each substation is summarized in Figure 4-4 to Figure 4-6 for Intertie Levels 1-3.

Figure 4-4 Substation GIC Flow – Intertie Level 1

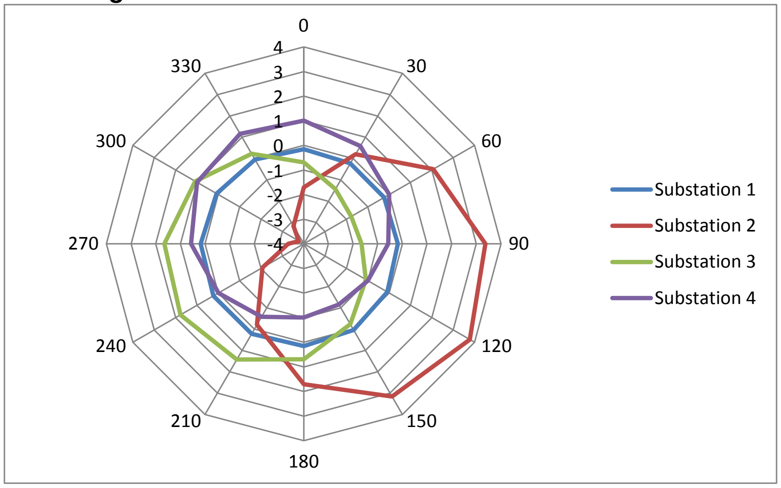


Figure 4-5 Substation GIC Flow – Intertie Level 2

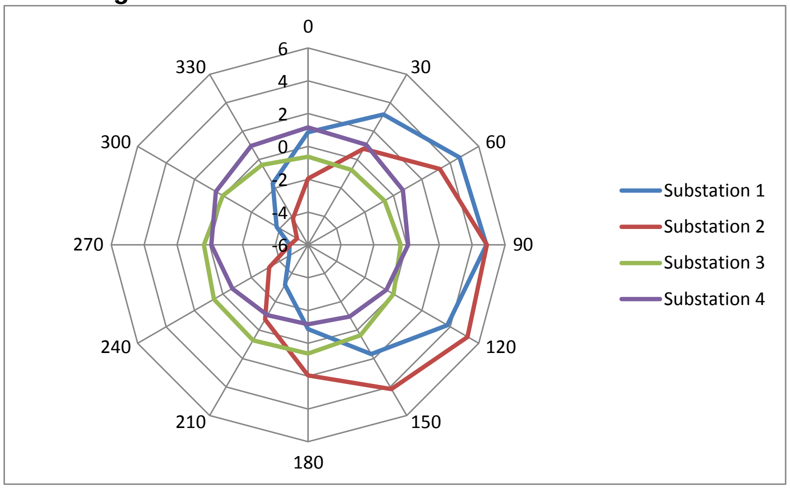
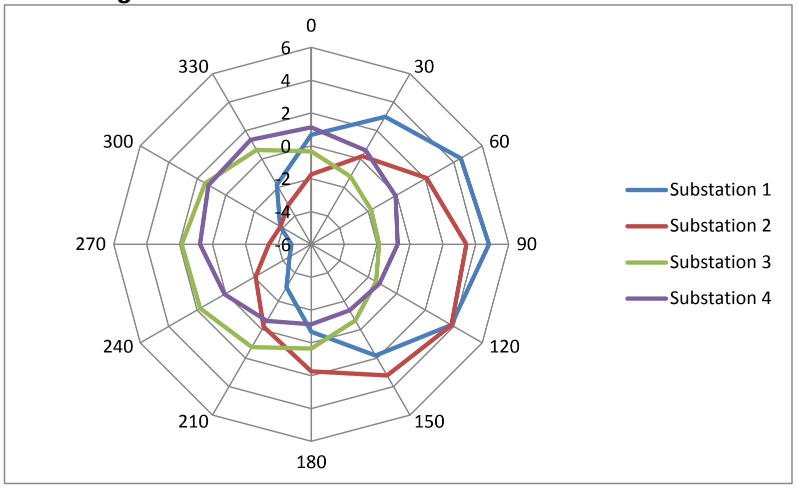


Figure 4-6 Substation GIC Flow – Intertie Level 3



The diagrams show the changes in the GIC magnitude (intensity of GIC) and shape (dependency to the GMD event angle). The substation GIC flow for Sub 1 (blue color) changed significantly from Intertie Level 1 to Intertie Level 2 while the GIC of other substations showed similar magnitude and shape. The reason why Substation 1 changed significantly was because the characteristic of the system changed from radial network to mesh network. As more substations were included in the model from Intertie Level 2 to Intertie Level 3, the GIC flow magnitude and shape became less sensitive. When the system is radially connected to the neighboring substation, the impact of GIC will be highly dependent on the transmission line orientation and the GIC flow from the neighboring substation. However, if the system is connected to a mesh network, the sensitivity to each neighboring substation decreases.

5.0 CONCLUSIONS

The main goal of this case study was to evaluate the impact of the neighboring system on GIC levels. The size of the neighboring system for the equivalent DC model was changed from Level 0 to Level 3 representing the complexity of the study area. The results of the analysis showed that the GIC will change significantly where the equivalent DC model's characteristic changes from radial network to mesh network. When the system was radially connected to the neighboring substation, the impact of GIC was highly dependent on the transmission line orientation and the GIC flow from the neighboring substation. However, if the system was connected to a mesh network, the sensitivity to each neighboring substation decreases. Thus, when a system planner develops the equivalent DC model and sets the boundary of the neighboring system, considering the characteristics of the neighboring system (radial network or mesh network) is recommended instead of setting a fixed boundary assumption applicable to all the connections. The modeling portion of this case study satisfied Requirement R2 of the NERC TPL-007-1 standard. While the maximum effective GIC is not presented in this paper, it was also a product of the case study and satisfied Requirement R5 of the NERC TPL-007-1 standard.

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A Practical Approach to Mitigating Risk Associated with Underream Foundations

Jeffrey Dupart, PE, PMP
Hari Vasudevan, PE

CenterPoint Energy

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The Problem

- 90-degree underream foundation failure in March 2013
  - Symptoms subsequently identified elsewhere

- Contributing factors
  - Lines reconductored
  - Increased tension due to cold
  - Sustained 90-degree loading
  - Changing soil properties
  - Improperly formed bell

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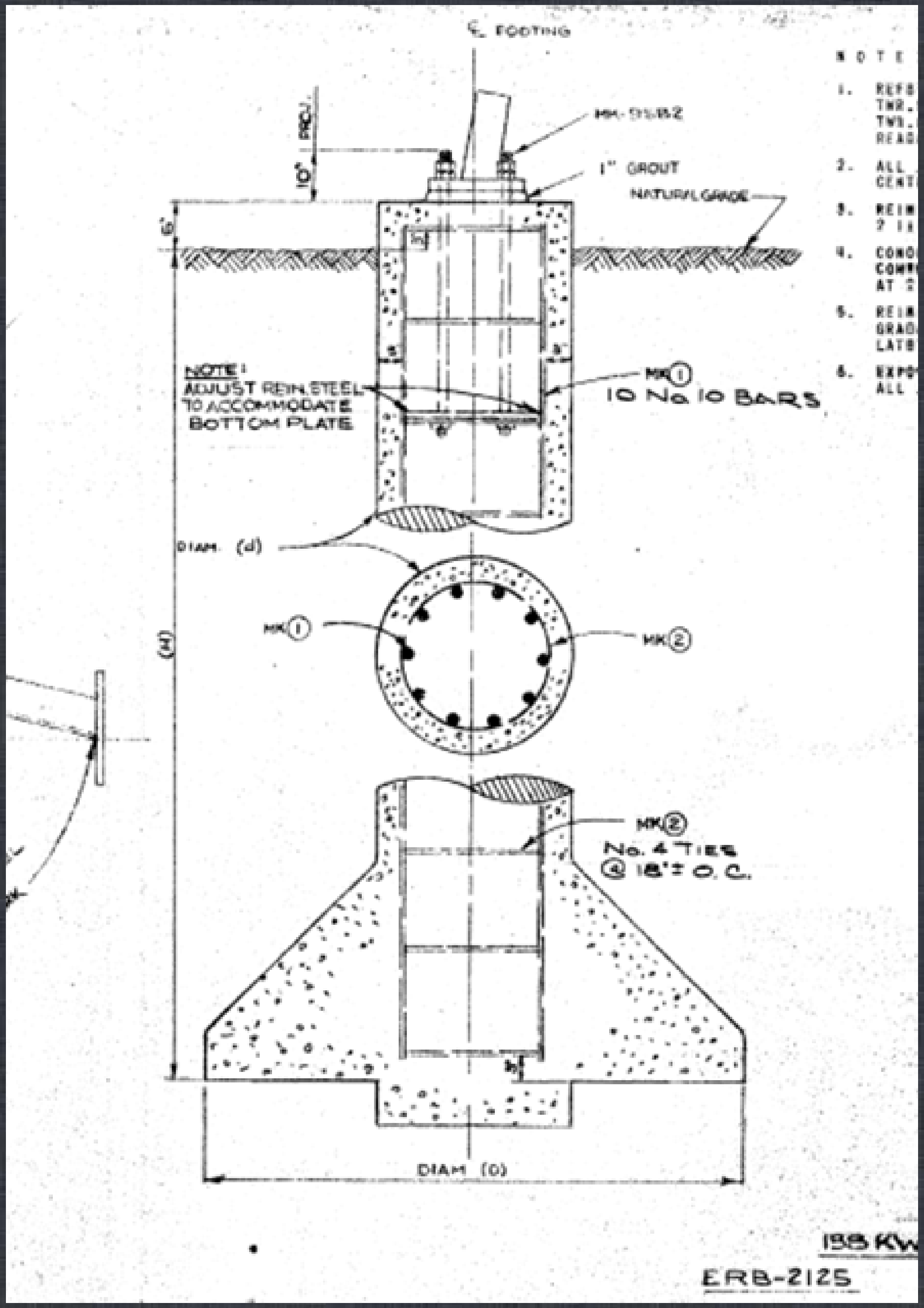
The Scope

- Approx 600 dead end and angle towers with underream foundations
- No easy fix to mitigate risks
  - Foundation replacement
  - Concrete dance floors
  - Foundation augmentations
- Evaluation of existing conditions a major effort



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Risk Index Methodology

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Risk Index

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Risk Likelihood Parameters

- Visible leaning of tower (RL-1)
- Foundation Racking (RL-2)
- Compression or uplift (RL-3)
- Bent tower members (RL-4)

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Risk Likelihood Weighting

	1	2	3	4	5
Visible leaning of tower (RL-1)				√	
Foundation Racking (RL-2)			√		
Compression or uplift (RL-3)		√			
Bent tower member (RL-4)	√				
RL-1 + any other RL					√
RL-2 + RL-3				√	
RL-2 + RL-4			√		
RL-3 + RL-4			√		
RL-2 + RL-3 +RL-4				√	

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Risk Severity

- Number of circuits
- Voltage Levels
- Bundling

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Risk Severity Weighting

Number of circuits

Voltage Level

	1	2+
69 kV	**1**	**2**
138 kV	**2**	**4**
345 kV	**3**	**5**

Add “1” to risk likelihood if 1 double bundle is present. For greater than one bundle add “2” to risk likelihood

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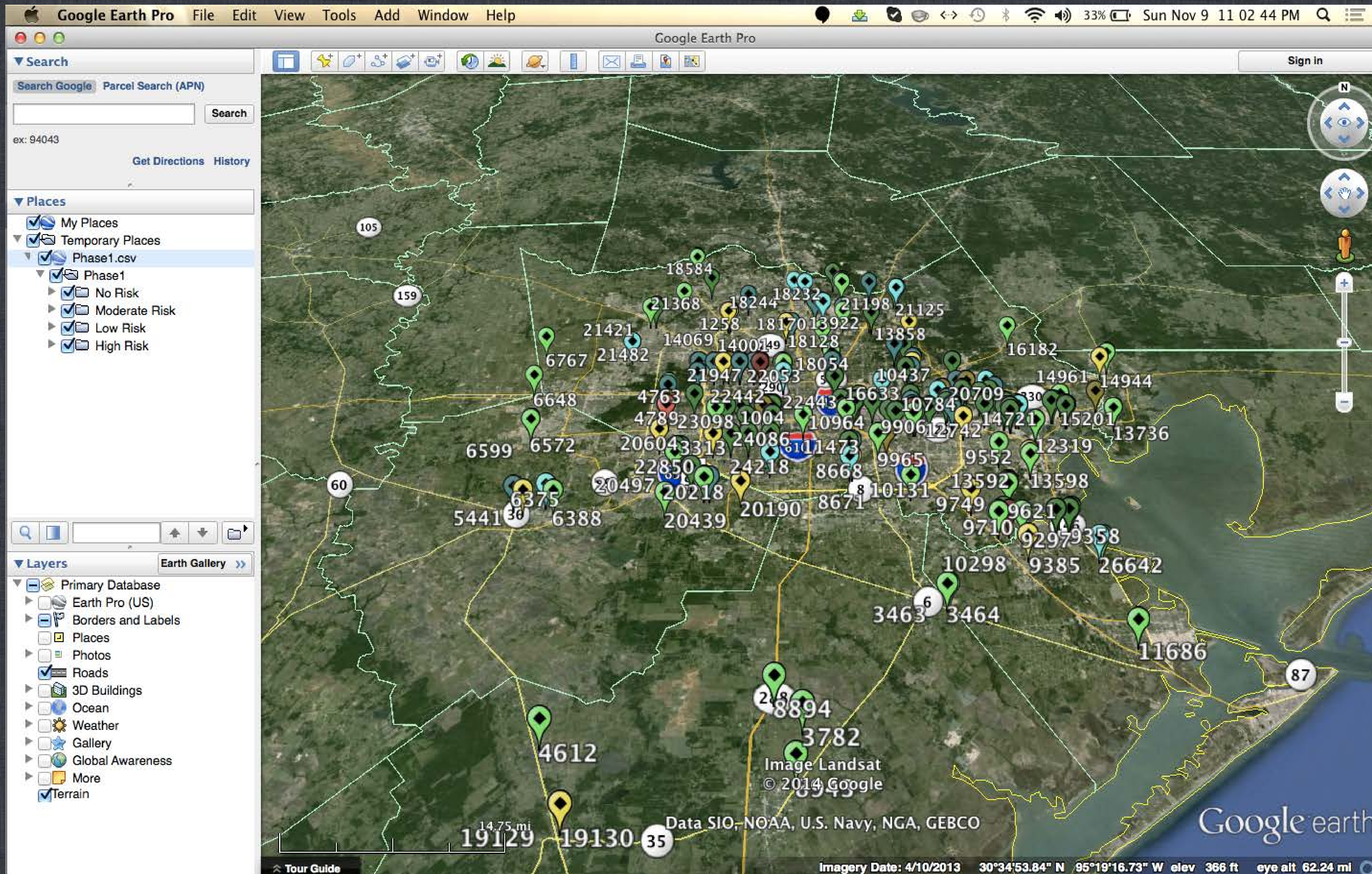
Risk Inspection Summary

Risk Index Mapping – Google Earth



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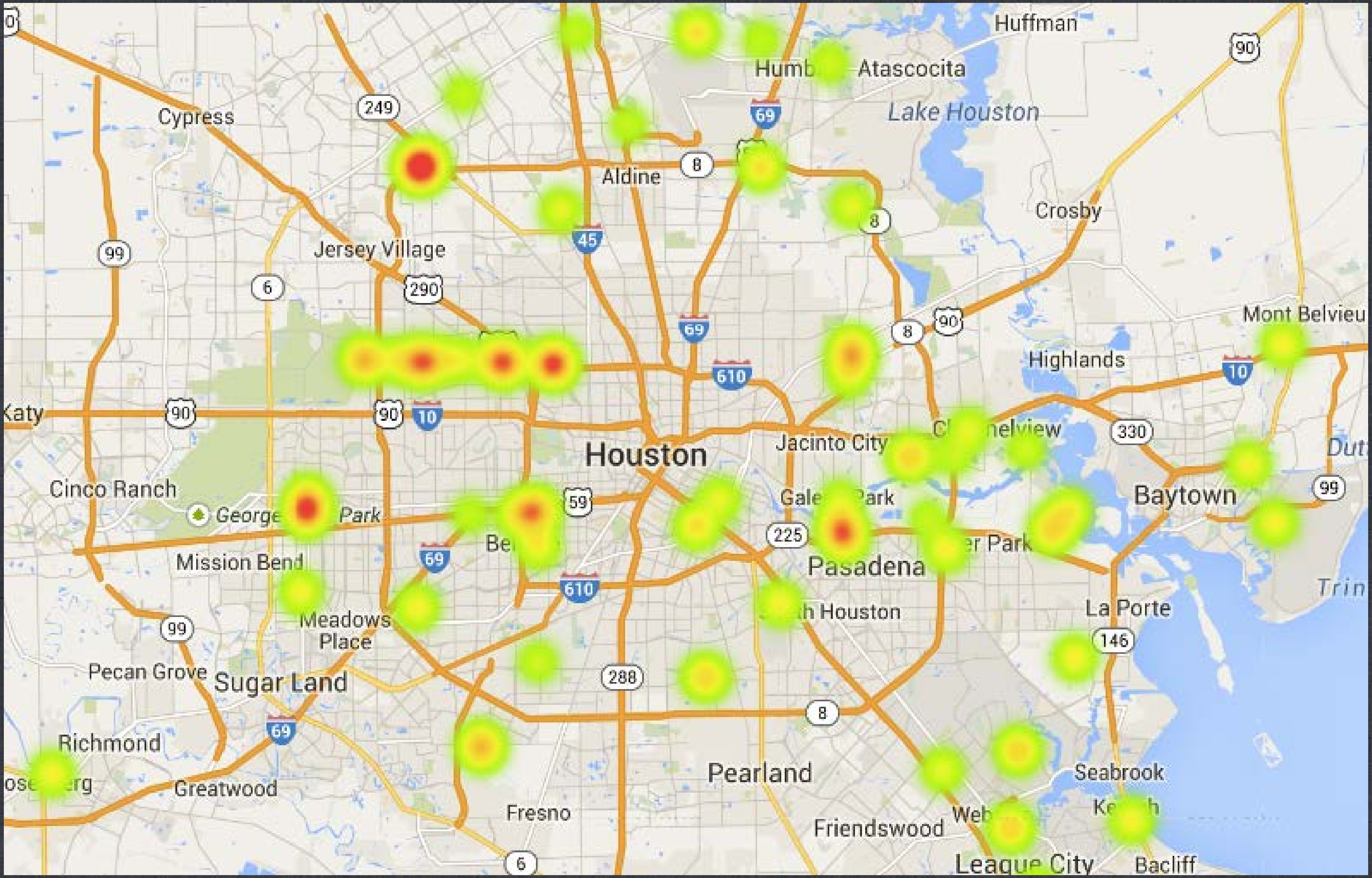
Heat Mapping (based on Risk Index)



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Risk Focus Areas

- Hwy 249 and Beltway 8
- Along Kempwood/Hammerly Drive
- Westpark Drive/ Synott

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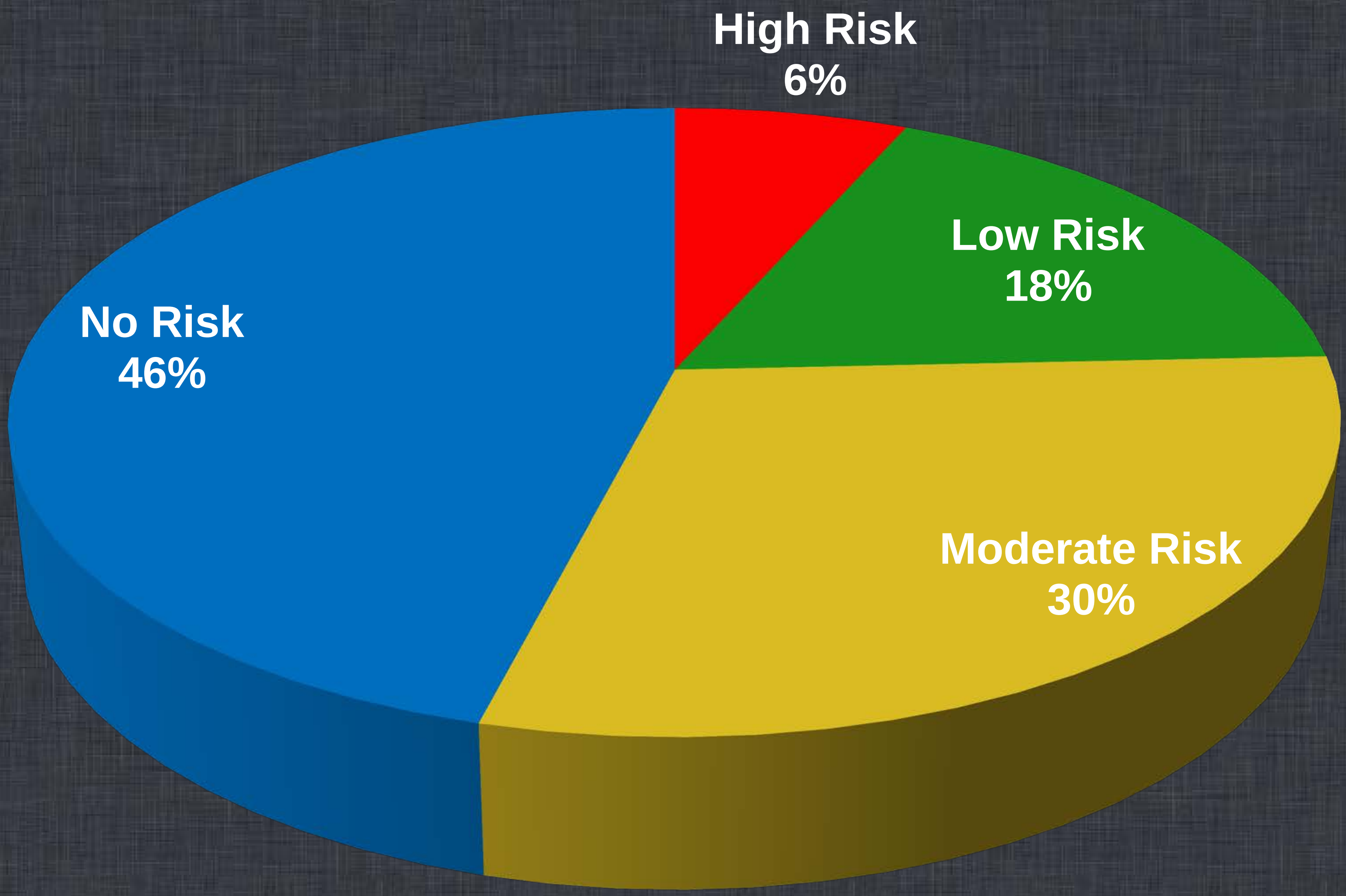
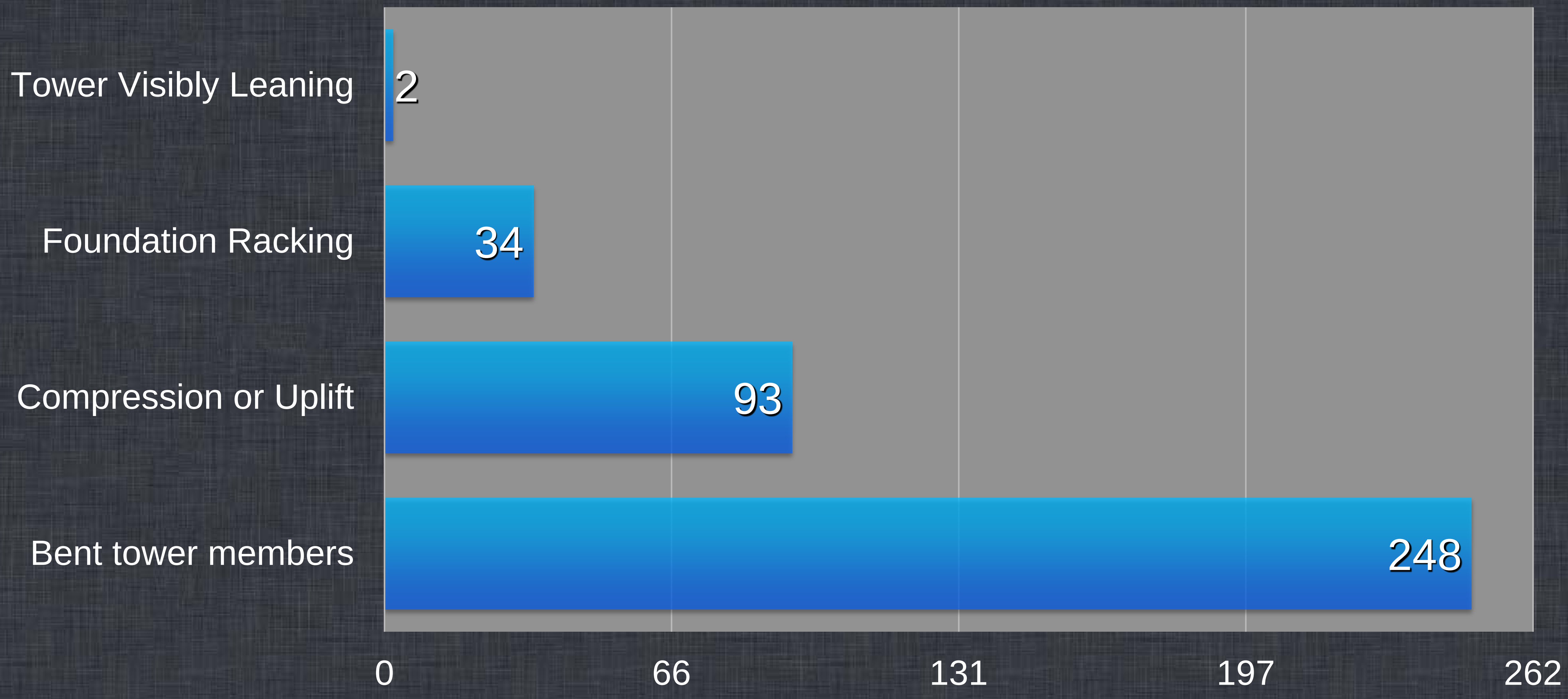
Risk Summary



Risk Likelihood



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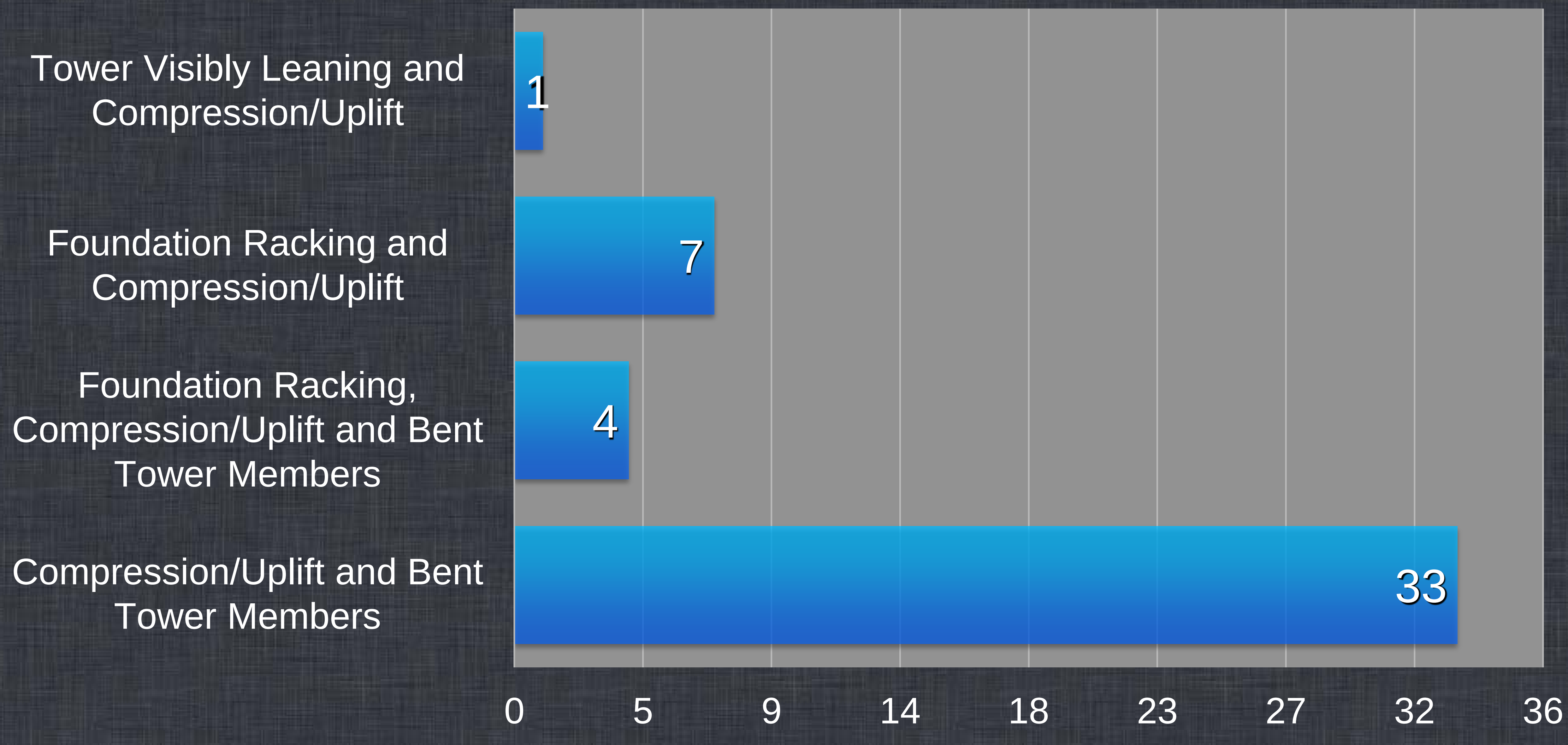
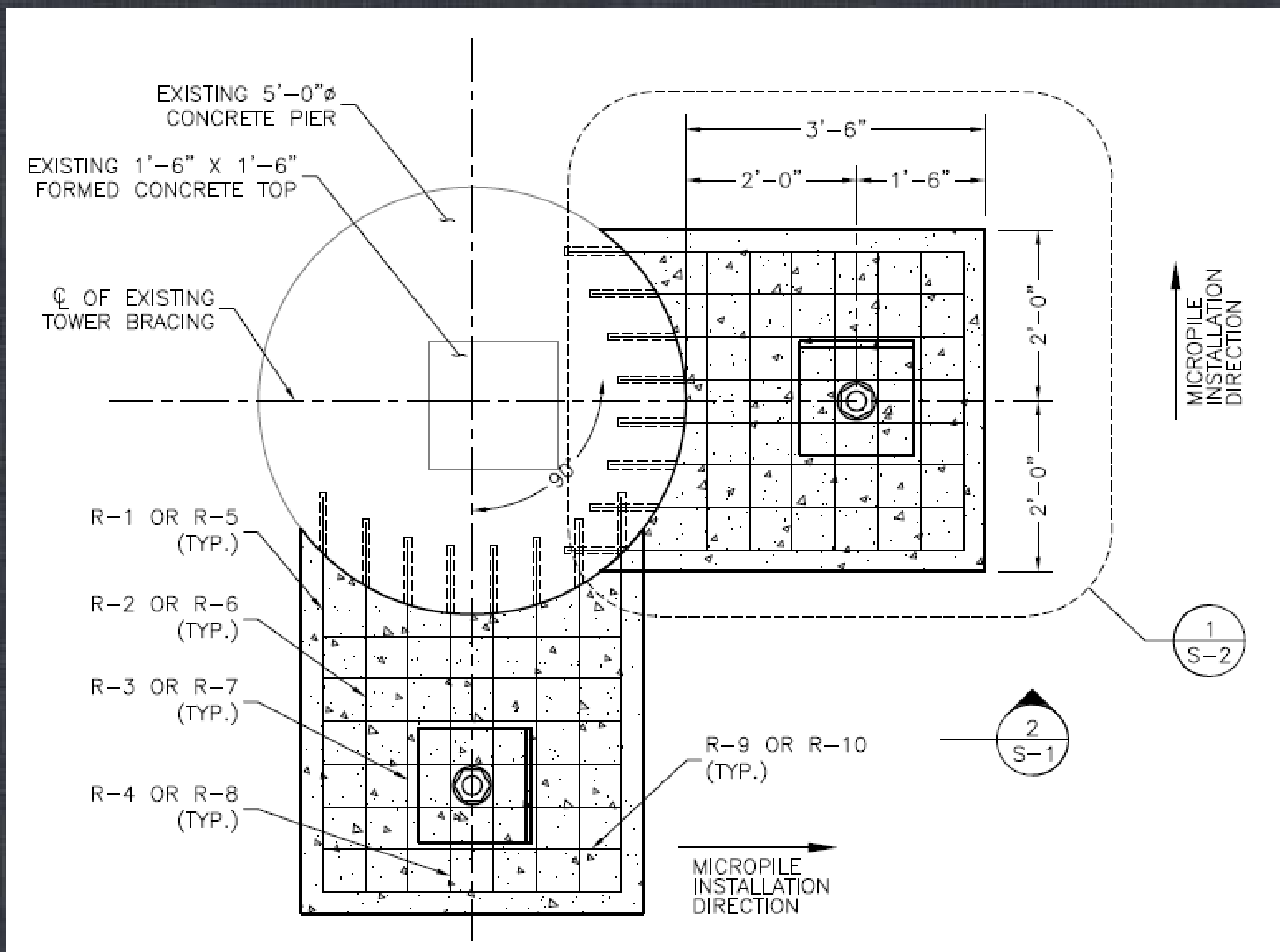
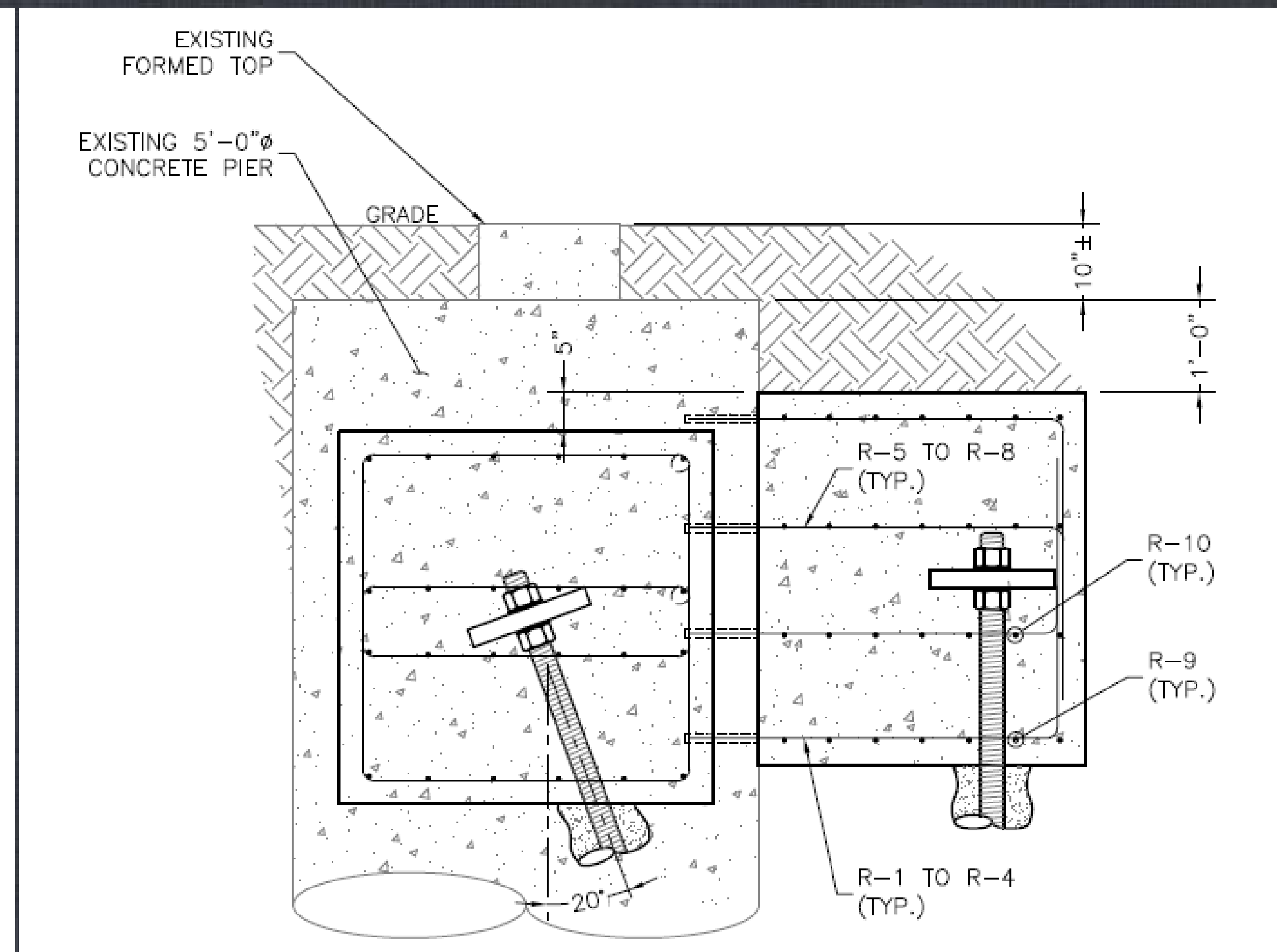
Risk Likelihood – Multiple Issues



Foundation Augmentation





- ➢ Working with FDH for nondestructive testing and micro pile foundation augmentation design

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Construction Photos

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Construction Photos

Program Management

- Work towards design standards
- Evaluate all dead end and angle underream foundations for new capital projects
  - 13 towers being augmented and several replaced
- Evaluate highest risk underream foundations based on Think Power diagnostics
  - 14 towers being augmented and one replaced

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Capacity Testing of Stationary Batteries in Substation Switchgear Applications

By Michael P. O'Brien, Technical Services Manager, Nolan Power Group, LLC

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Introduction

Stationary batteries, VLA, (vented Lead-Acid), VRLA, (Valve Regulated Lead-Acid), and Nickel-Cadmium, (NiCd), batteries provide critical control power for circuit breaker, relay, and communication operations in transmission and distribution substations. The battery is the heart of the protection and control system for the substation and therefore must be a highly reliable source of power. Capacity testing is an integral part of a comprehensive maintenance program and required by NERC Standard PRC-005-2. Capacity testing is much more than simply applying a load to a battery. Experience has shown that many capacity tests are performed incorrectly, often using incorrect discharge rates and terminated prematurely. Improper capacity testing yields incorrect results which can jeopardize substation operation. This paper explains how to select the proper test method, discharge rate, test execution, and test frequency in accordance with IEEE standards 450-2010, 1188-2005, 1106-2005 and NERC Standard PRC-005-2.

Why Capacity Test?

Capacity testing of stationary battery systems has been a key component of comprehensive preventative maintenance programs since the first version of IEEE 450 was issued in 1972. Today, capacity testing is required by NERC Standard PRC-005-2 and a key component of IEEE standards 450-2010, 1188-2005, 1106-2005. Properly conducted capacity tests are the only method of determining and quantifying stationary battery discharge performance. Internal ohmic measurements, (impedance or internal resistance measurements), while valuable, do not measure battery/cell capacity and are not a replacement for capacity tests. Properly designed and performed capacity tests will prove that the battery can, or cannot, support a worst case trip condition, as well as determine how much useable life is left in a battery system thus allowing for planning and budgeting stationary battery replacement. Capacity testing also provides baseline performance data, aids in identifying manufacturing defects, installation deficiencies, and incipient problems not detectable by other means.

Effect on Life

Properly conducted capacity tests are not destructive tests. Capacity tests are consumptive in nature, meaning that some battery life is consumed in the test. The amount of battery life consumed by capacity testing depends upon the specific type of battery, depth of discharge, and test frequency. Stationary Battery life is rated in years of float service and a number of discharge cycles. Flooded Stationary Batteries of U.S. manufacture typically have a design life of 20-years of float service or “X” number of discharge cycles, whichever occurs first. Flooded pasted plate lead-calcium cells have a cycle life of approximately 50 deep discharges. This is the lowest rated cycle life of any commonly used Stationary Battery. In Stationary Batteries a deep discharge is defined as an 80% depth of discharge.

End Voltage

End Voltage is a system design parameter. This is the voltage at which a discharge is supposed to stop. End Voltage is normally expressed in Volts Per Cell. There is nothing within a Stationary Battery or substation that automatically stops a discharge. The most common End Voltage used in North America is 1.75 Volts Per Cell. Capacity Tests should use the DC system design End Voltage as the end of test voltage. In a system using 60-cells and an End Voltage of 1.75 Volts Per Cell a capacity test would terminate when the battery voltage dropped below 105.0VDC at the battery terminals. Properly conducted capacity tests only stop on voltage and never stop at a specific discharge time.

Designing the Capacity Test

A capacity test is basically a constant load discharge of the battery to a specified end voltage. Varying the discharge load during a capacity test will induce capacity errors due to the non-linear discharge performance of commonly used stationary batteries. The amount of capacity error depends upon the amount of load deviation, the time in the discharge of the load deviation, the duration of the load deviation, and the battery chemistry. A short duration load deviation at the beginning of a capacity test will induce a very small capacity error, typically less than 2%.

The goal of a capacity test is to measure the useable battery capacity and to prove that the battery will support the connected load during a worst case event. Batteries can produce different measured capacities at different discharge rates and this effect becomes more pronounced as the battery ages. This change in measured capacities at different discharge rates is primarily due to increased efficiency losses within the cells as they age. High current capacity usually falls off much earlier in life than low current capacity. Therefore, if a battery must supply high currents, even momentarily, it is imperative that the capacity test prove that the battery can supply these required high currents.

A properly designed capacity test should objectively and repeatedly measure the capacity of the battery as it is used in a specific substation. It should be designed in a manner to envelope the battery duty cycle, as much as practical, in order to prove the battery will, or won't, support the connected emergency loads and measure the battery capacity.

Modified Performance Test

Unfortunately, substations don't have a constant DC load during a worst case trip condition. Substations have a complex DC load profile; therefore a "Modified Performance Test" is required to prove the battery can deliver the high current required during a worst case trip and the amp-hour capacity needed to sustain the substation during an AC power outage. Typically, the highest loads occur during the first few seconds of a worst case trip as circuit breakers trip and other devices operate. The load drops significantly after the first minute as the battery now only has to power the steady state loads over a time period that usually stretches for hours. A typical load profile might look something like this:

Sizing Parameters	
Application:	Switchgear
Lowest Temp (°F):	50.00
Min. Voltage (Vpc):	1.75
Design Margin:	1.10
Aging Factor:	1.25

Battery Load Details	
Number of Cells:	60
Total Time (Minutes):	480.00
Amp Hour Removed:	83.42

Period	Time (Mins.)	Load
1	1.00	170.00 A
2	477.00	10.00 A
3	1.00	45.00 A
4	1.00	20.00 A

Most Critical Load

The most critical portion of this load profile is the first minute. It is in the first minute that the maximum number devices, (circuit breakers, circuit switchers, etc.) have to operate. It won't matter how long the battery can support the steady state loads if the battery can't supply the energy required trip the circuit breakers. Therefore, the capacity test must require the battery to supply the peak currents, but only for as long as those currents would be present or for as long as the battery is sized to carry them. Note: IEEE 485 requires lead-acid batteries to be sized to support these transitory loads for a full minute even though their duration may be considerably less than one minute.

A battery capable of supporting the load profile shown above, (3CC-9M), is rated to support a load of 202.6 amps for 15 minutes to an end voltage of 1.75 volts per cell @ 77^{o}F. A capacity test at this rate would prove that the battery can support the peak loads; however, a test at the 15-minute rate would be more severe than the complete duty cycle, which in the example above is 480 minutes (8-hours). Thus testing at only the 15 minute rate would likely result in premature replacement of the battery because high rate capacity generally falls off early, as previously stated. Therefore, the first period of a Modified Performance test for this battery should be 170 amps for 1-minute. This proves the battery can support a worst case trip condition.

Amp-Hour Capacity

The remainder of the load profile uses relatively low currents; therefore the test must prove that the battery has sufficient amp-hour capacity while supporting the next highest current. The load profile example above requires the battery produce a total of 83.42 amp-hours of energy. Therefore the second and final period of the load test should require the battery to produce at least 83 amp-hours of energy. The published 3-hour discharge rate for the 3CC-9M is 51.4 amps to an end voltage of 1.75 volts per cell @ 77^{o}F. This discharge requires the battery supply 154.2 amp-hours of energy which is 70.8 more amp-hours of energy than required by the design load profile. This is also a 77.1% depth of discharge.

The published 1-hour discharge rate for the 3CC-9M is 107.8 amps to an end voltage of 1.75 volts per cell @ 77^{o}F. This discharge requires the battery supply 107.8 amp-hours of energy which is only 24.38 more amp-hours of energy than required by the design load profile. This is also a 53.9% depth of discharge.

Correct Test Rate

This Modified Performance test will have two periods. The first period will be at a load of 170-amps for a duration of 1-minute. The second period load can be either the published 1-hour rate of 107.8 amps or the 3-hour rate of 51.4 amps. Both rates are technically correct and either rate will prove that the battery can support the switchgear under worst case conditions and measure battery capacity. The author would choose the 1-hour rate because less battery life is consumed and less time is required at the job site. The 1-hour Modified Performance test will have a capacity error of approximately 0.96% and the 3-hour Modified Performance test will have a capacity error of approximately 1.3%

Removing a Substation Battery from Service for Testing

A Stationary Battery is normally removed from service for capacity testing. And, since most substations do not have redundant batteries a temporary battery is normally required.

A suitable temporary battery is a battery, cabling, and connection method that can supply the highest currents required by the DC system in a worst case trip condition. A suitable temporary battery must be paralleled onto the DC bus before the Station Battery is electrically isolated for testing.

The battery charger should not be relied upon to support the switchgear without a suitable battery connected. Industrial battery chargers are not power supplies and even those with output filtering cannot normally supply the current required in a worst case trip condition. Unfiltered chargers will not be able to maintain the proper output voltage without a battery connected to the DC system.

Temporary Battery

A suitable temporary battery must be capable of supplying the highest currents required by the DC system in a worst case trip condition. It must also be capable of surviving highway travel. Stationary VLA Batteries are not designed to withstand the vibration and mechanical shock involved in highway travel and do not make a reliable temporary battery. Batteries designed for Motive Power and Railroad applications usually make good temporary batteries. Some VRLA and NiCd batteries make good temporary batteries. Automotive or SLI, (Starting, Lighting, & Ignition), batteries should be avoided because they have very thin plates that will not tolerate the positive plate oxidation that occurs during float charging. Automotive or SLI batteries are often unreliable after as little as 90-days on float charge.

Test Equipment

The test equipment should be a computer-based battery discharge test system with automatic data logging. It should be capable of conducting multi or single step, constant current or constant power (KW) discharge tests. It should include a video display of all pertinent data relating to a discharge test such as:

Individual cell voltages	Load/discharge current
Overall battery voltage	Average cell voltage
Minimum cell voltage	Maximum cell voltage
Elapsed test time	Program step number
Program step elapsed time	Battery location
Battery identification number.	

Individual cell voltages should be displayed in a bar graph format, allowing the test engineer/technician to spot failing cells or abnormal conditions at a glance. All changes of individual cell voltages, overall battery voltage, and test current should be automatically recorded for later retrieval.

The load bank(s) should be DC voltage rated, single phase, air-cooled load banks. The load current should be adjustable in one amp steps throughout the range of the load unit.

Test Procedure

The substation battery should be isolated from the DC system during testing; therefore, a temporary battery will be required to support the switchgear and any operating control circuits. Do not allow the battery charger to serve the DC system without a battery connected.

1. Ensure the battery has received an equalization charge at least three days, but no more than thirty days, before the test. IEEE standards allow this step to be omitted when the test is performed with the battery in the “as found” condition. An ‘as found” test is a test of the battery and the battery maintenance program.

2. Measure and record the electrolyte temperature of at least 10% of the cells and calculate the average temperature.

3. Measure and record the specific gravities of all VLA cells.

4. Measure and record the individual cell float voltages.

5. Parallel portable battery plant with station battery.

6. Isolate the station battery from the DC system.

7. Connect test equipment to battery.

8. Program the test equipment.

9. Initiate the capacity test. The load must be maintained at the specified levels throughout the test until the battery terminal voltage drops below the specified end voltage.

   NOTE: Capacity tests are not stopped after reaching a specified discharge time. Capacity tests are only terminated when the battery terminal voltage drops below the specified end voltage. Example: End voltage per cell times the number of cells in series equals the battery terminal end voltage, 1.75 (per cell end voltage) x 60 (cells in series) = 105.0 VDC (battery terminal end voltage). The capacity test would end when the battery terminal voltage dropped below 105.0 VDC.

10. Check for overheated connections during the test. If the temperature rise across any connection becomes unacceptable, pause or terminate the test as appropriate.

    NOTE: High resistance connections will show as low voltage cells during the test. This is because the cell voltage measurements include the voltage drop across the cell's associated intercell connector. Normally, but not always, a cell showing low voltage during the first thirty to sixty seconds of a capacity test is not truly a low voltage cell but a high resistance connection.

11. If the voltage of any lead-acid cell approaches polarity reversal, less than one volt, pause the test, jumper around the cell, and resume the test to the new end voltage. The test pause time should be no more than 10% of the specified test time, (6-minutes for a 1-hour test).

    CAUTION: Isolate the cell to be jumpered before connecting the jumper. Do not short circuit the cell being jumpered.

    CAUTION: Cells should not be allowed to go into polarity reversal as this causes irreparable damage to the cell and can pose a safety hazard.

    NOTE: NiCd cells can be allowed to enter polarity reversal. See IEEE Std. 1106-2005 for additional information.

12. At the conclusion of the test, record the elapsed test time, disconnect all test equipment.

13. Parallel station battery with portable battery plant.

14. Monitor the initial recharge and, if necessary, adjust the charger output current limit.

15. Disconnect the portable battery plant.

Capacity Calculation

Divide the actual time of the test by the temperature corrected specified test time and multiply by 100. The temperature correction factors for VLA batteries are found in IEEE Std. 450-2010 table L.1. The temperature correction factors for VRLA batteries are found in IEEE Std. 1188-2005 table F.1. There are no industry standard temperature correction factors for NiCd batteries. Contact the battery manufacturer when the average cell temperature is less than 20^{o}C. for NiCd batteries. The capacity of NiCd batteries does not substantially increase when the electrolyte temperature is above the standard temperature.

VLA Test Frequency

VLA batteries should receive an Acceptance Test upon installation and a Modified Performance Test after 2-years of service. Additional Modified Performance Tests should be conducted at intervals not exceeding 25% of the battery's Expected Service Life. Annual Modified Performance Tests are required when the battery reaches 85% of its Expected Service Life or when signs of degradation are noted. Signs of degradation are a drop in capacity of 10% or more from the previous capacity test or when the capacity is 90% or less. Expected Service Life can be calculated following the formula found in IEEE Std. 450-2010 Annex H.

VRLA Test Frequency

VRLA batteries should receive an Acceptance Test upon installation. Additional Modified Performance Tests should be conducted annually. The interval between Modified Performance Tests can be lengthened to 2-years only when there are no issues with the battery.

NiCd Test Frequency

NiCd batteries should receive an Acceptance Test upon installation and a Modified Performance Test after 2-years of service. There may be a substantial difference in the measured capacities between the Acceptance Test and first Modified Performance Test because the "Float Effect" may not have fully developed at the time of the Acceptance Test. This is not a capacity loss but a difference in performance due to different charging regimes. Additional Modified Performance Tests should be conducted every 5-

years thereafter until the battery exhibits signs of excessive capacity loss. Excessive capacity loss is a loss of capacity that exceeds 1.5% per year from the previous capacity measurement. Annual Modified Performance Tests are required after an excessive capacity loss is noted.

NERC Standard PRC-005-2 Test Frequency

NERC Standard PRC-005-2 requires that VLA and NiCd batteries receive a capacity test at least every 6-years and VRLA batteries at least every 3- years. Capacity testing at these frequencies may meet legal requirements, but it does not ensure that a substation battery will support the connected load when called upon.

VLA & VRLA Battery Capacity Based Replacement Criteria

Stationary Lead-Acid batteries require replacement when their capacity drops to 80% of the manufacturer's rating. VLA batteries at 80% capacity should be replaced within 1-year. VRLA batteries at 80% capacity should be replaced within 6-months. Batteries that fail to support the first period load require immediate replacement as they will not support a worst case trip condition.

NiCd Battery Capacity Based Replacement Criteria

Stationary NiCd batteries do not have a universal replacement capacity. NiCd's typically have a linear loss of capacity over time and thus the replacement capacity is decided during the sizing process. Replacement should occur within 1-year once the minimum design capacity has been reached. Batteries that fail to support the first period load require immediate replacement as they will not support a worst case trip condition.

Conclusion

There is no substitute for properly designed, instrumented and conducted battery capacity tests. These tests are the only scientific method of proving that a station battery will support the connected load and the only scientific method of determining when to replace your station battery. Can your substation battery support a worst case trip condition?

References

1. IEEE Std. 450-2010, Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications.

2. IEEE Std. 1188-2005, Recommended Practice for Maintenance, Testing, and Replacement of Valve-Regulated Lead- Acid (VRLA) Batteries for Stationary Applications.

3. IEEE Std. 1106-2005, Recommended Practice for Installation, Maintenance, Testing, and Replacement of Vented Nickel-Cadmium Batteries for Stationary Applications.

4. IEEE Std. 485-2010, Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications

48th ANNUAL TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM

Challenges in Performing Engineering Analysis of Existing Lattice Towers!!!

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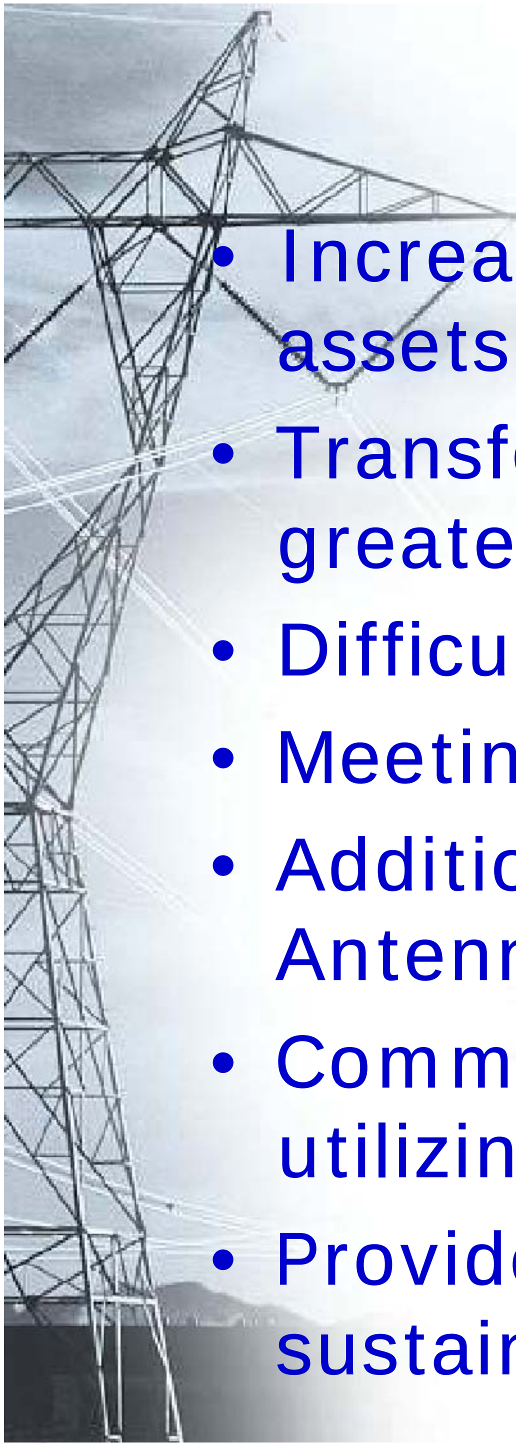
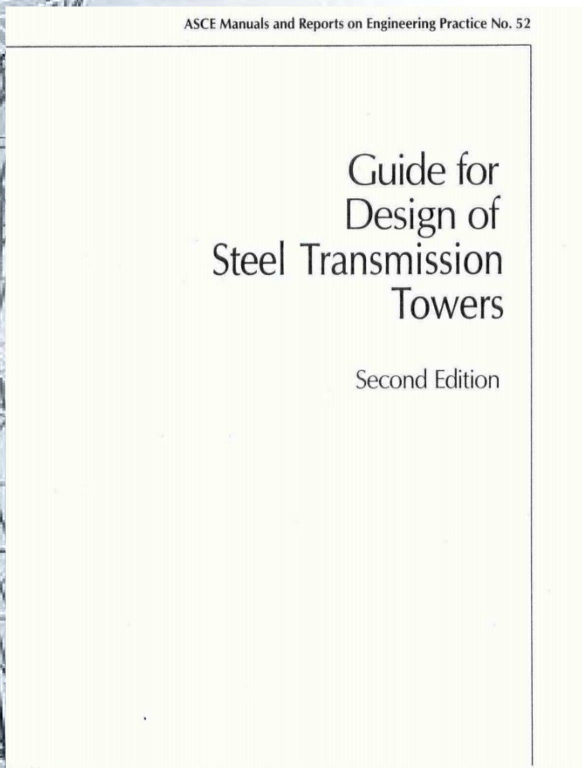


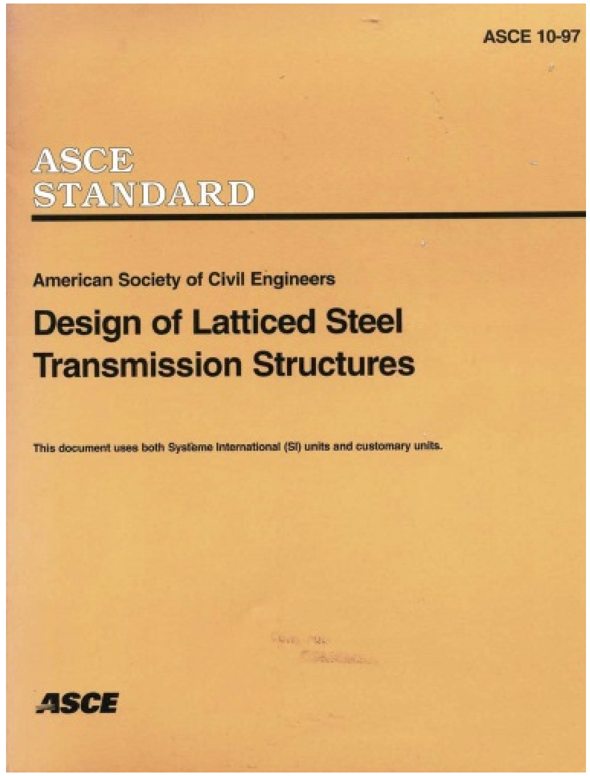
Upgrading/Uprating

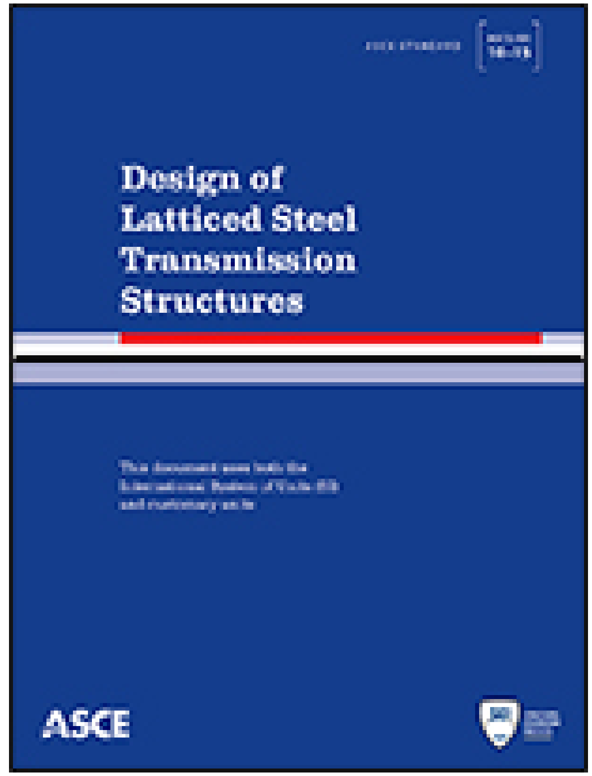
- Increase electricity demand with existing assets
- Transfer power over long distances with greater load than original design conditions
- Difficulty in obtaining new Rights of Way
- Meeting NERC requirements
- Additional loading by adding OPGW and Antenna systems
- Common practice to upgrade/uprate utilizing existing towers
- Provide low cost, affordable and sustainable options

Transmission Line Towers

Design Standards: Steel Towers







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Transmission Line Structures

- Transmission Structures play a very critical role in building robust and reliable transmission infrastructures
- Complex in design and require a high degree of skill and experience to properly design, manufacture and meet the quality standards
- Support the phase conductor and Shield wires/OPGW of a Transmission Line
- Steel Tubular poles: 345 kV or less
- Lattice Steel Towers: Higher than 345 kV

Transmission Structure Families

- Depends on line route and type of terrain
- Most common type
  - Tangent/Suspension (0-2 Deg)
  - Long Span Tangent (0-2 Deg)
  - Light Angle (2-15 Deg)
  - Medium Angle (15-30 Deg)
  - Heavy Angle (30-60 Deg)
  - Dead End (0-90 Deg)
- Tangent Structures: Approx. 80%

Transmission Structure Families

Contd...

- Special application Structures
  - River crossing
  - Transposition Phase changing
  - HVDC Line
  - Containment Situation

Tower Materials

- Typically, a lattice tower is comprised of various sizes of structural angle profiles (80%), steel plates (8%), fasteners (7%), Zinc (5%)

- Most common ASTM steel grades
  - A36: Fy= 36 ksi, Fu = 58–80 ksi
  - A572 Gr- 50: Fy= 50 ksi, Fu = 65 ksi
  - A709 Gr- 50S: Fy= 50 ksi, Fu = 65 ksi
  - A572 Gr- 60: Fy= 60 ksi, Fu = 75 ksi
  - A394, Type 0 or 1

Tower Materials Modern Steel

Contd…

- Recycled and Scrap Based
- As-rolled Conditions
- Electric Arc Furnace
- Continuous Casting

- Silicon-Killed (Deoxidation)
- Al-Killed (Expensive method)
- Varying combinations of Micro-Alloyed
- Several Foreign stinger inclusions
- Reactive Steel- Higher galvanizing coating

Tower Materials
Preferred Steel

Contd...

- Non Reactive Steel- Silicon control
- Al-killed Steel
- Charpy V-Notch: 15 ft-lbs at -20 Deg F
- Carbon < = 0.25%
- Phosphorous < = 0.04%
- Manganese < = 1.3%
- Silicon < = 0.04% or range 0.15 - 0.25%
- Limit Max. Tensile Steel = Range 65-70ksi

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Tower Materials Preferred Steel

Contd…

- Where appearance (uniform Dull finish) is important:
  - For cold rolled steel:
    - $Si < 0.03$ and $Si + 2.5 \times P < 0.04$ weight percent
  - For hot rolled steel:
    - $Si < 0.02$ and $Si + 2.5 \times P < 0.09$ weight percent

Tower Geometry Requirements

- Length of the insulator assembly
- Min. clearances between conductors
- Min. clearances between conductors and tower
- Location of Ground wires and shielding angle for lightning protection
- Mid span clearance for dynamic behavior of conductors
- Min. clearance of the lowest conductor above ground line

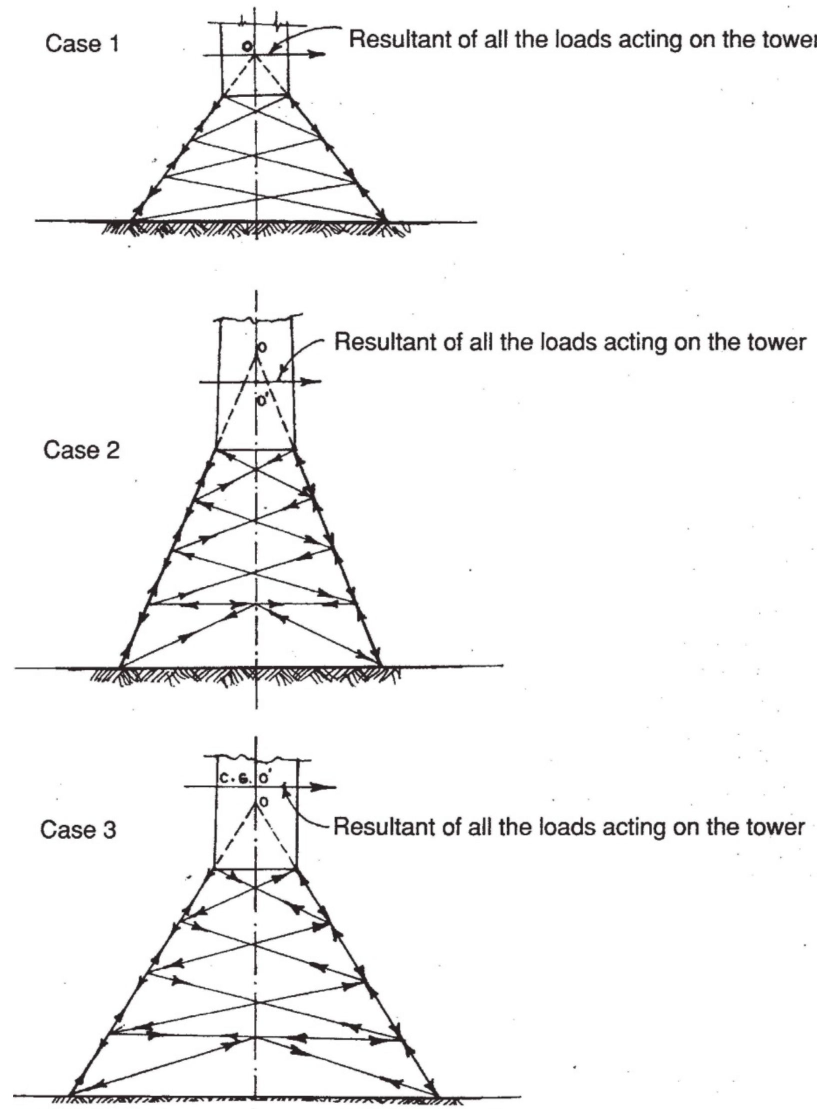
Slope of Towers

- Slope of the legs should be such that the corner members intersect near the center of gravity (CG) of the loads
- General Guidelines (Self Supported):
  - Tangent Towers: 8 – 15 deg
  - Med. Angle Towers: 15 – 20 deg
  - Heavy Angle Towers: 20 – 25 deg
  - Deadend Towers: 25 - 30 deg

Slope of Towers

Contd...

- Case 1: Ideal conditions. Bracings carry no forces
- Case 2: Most common conditions. Legs and bracings share the forces
- Case 3: Not recommended. Leg carry more forces than bracings



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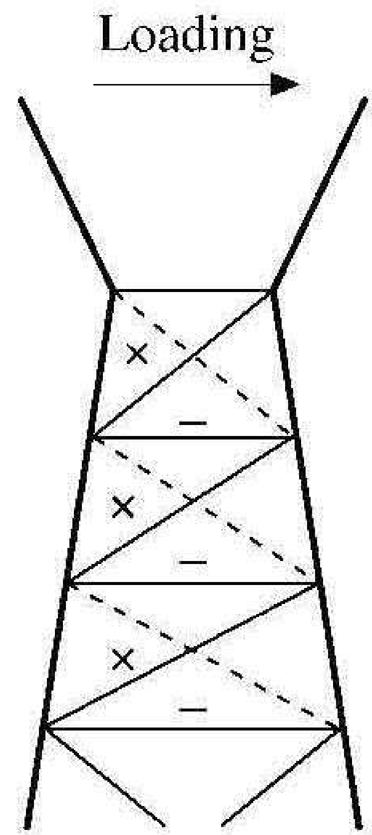
Bracing Systems Tension Only

- Bracing members below the waist can be designed as a tension only
- In a tension only system, the bracing members are designed to carry tension forces only, the compression forces being carried by the horizontal strut
- Economical for tangent towers

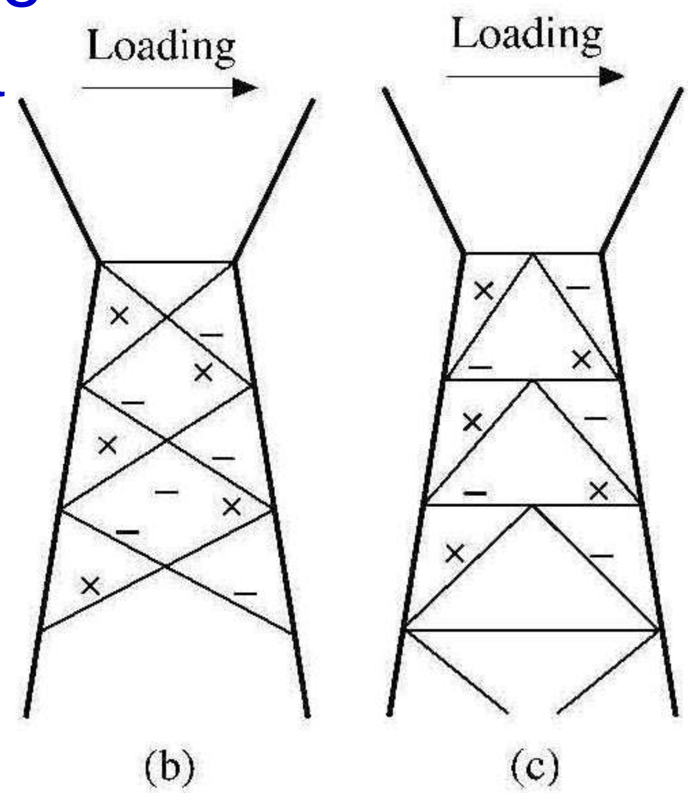


(a)

Bracing Systems- Tension/Compression

Contd…

- Bracing members below the waist can be designed as a tension/compression system
- In a tension/compression system , the braces are designed to carry both tension and compression
- Suitable for Angle and Deadend towers



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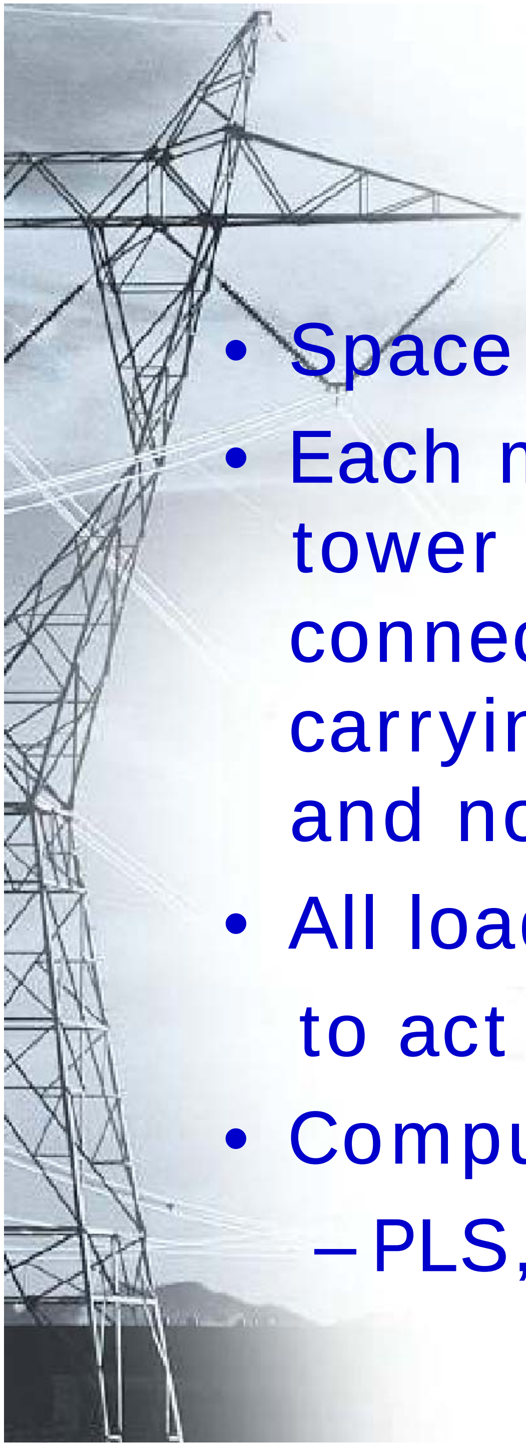
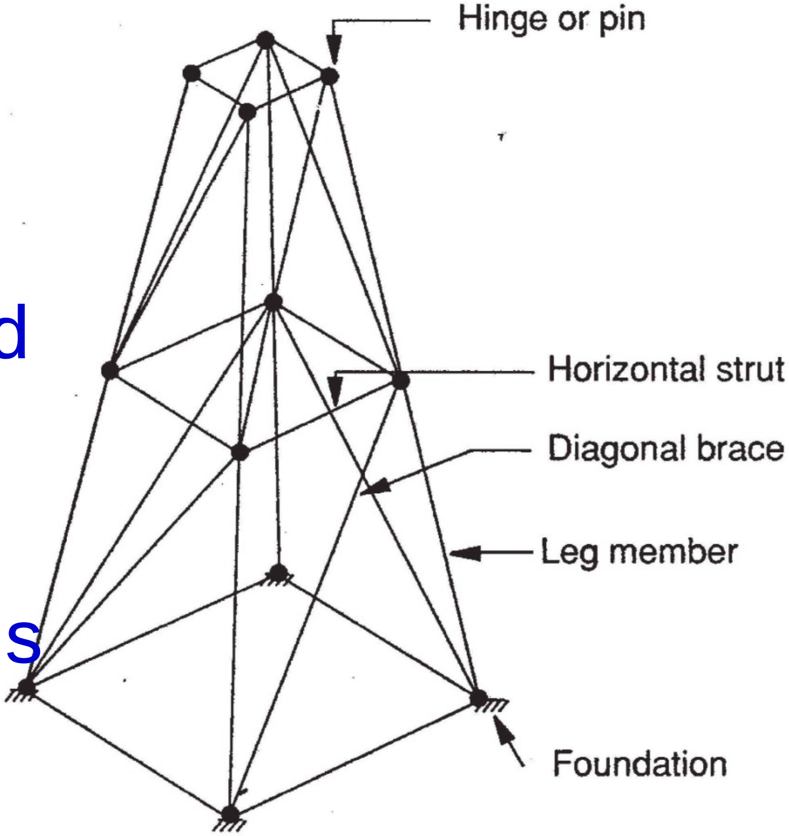


Tower Analysis

- Space Truss Idealization
- Each member of the tower is assumed pin-connected at its joints carrying only axial load and no moment
- All loads are assumed to act only at the joints
- Computer Program:
  – PLS, ATADS



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Tower Design

- Tower is made up of a basic body, body extension, and leg extensions.
- Standard designs are developed for a given tower type with a common the basic body
- Primary members of a tower are the leg and the bracing members which carry the vertical and shear loads on the tower and transfer them to the foundation

Tower Design

- Secondary or redundant bracing members are used to provide intermediate support to the primary members to reduce their unbraced length and increase their load carrying capacity
- Slope of the tower leg from the waist down has a significant influence on the weight and should be optimized to achieve an economical tower
- A flatter slope results in a wider tower base, which reduces the leg size and the foundation size, but will increase the size of the bracing.

Tower Design Effective lengths (KL/r)

Contd...

- Where “L” is the length of the member
- “K” is a non-dimensional factor which accounts for different fixity conditions at the ends, also known as restraint factor
- Effective slenderness ratio “KL/r” depends on:
  - Type of bolted connection
  - # of bolts used for the connections
  - Length of the member
  - Effective radius of gyration

Tower Design

Contd...

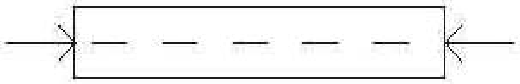
Effective lengths (KL/r)

- (KL/r)max = 150 for Leg members
- (KL/r)max = 200 for Other members
- (KL/r)max = 250 for Redundant members
- (KL/r)max = 500 for Tension-only members
- (KL/r)min = 300 for Tension-only members

Tower Design

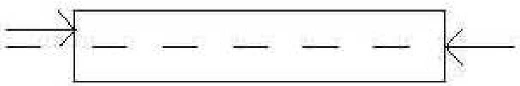
Contd...

Member End Conditions



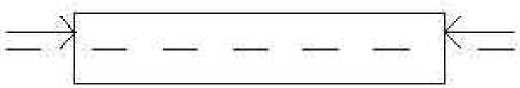
1) NO ECCENTRICITY

4) NO ROTATIONAL RESTRAINT AT ENDS

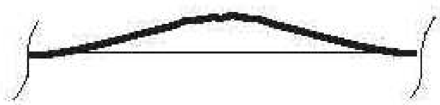


2) ECCENTRICITY ONE END

5) ROTATIONAL RESTRAINT ONE END ONLY



3) ECCENTRICITY BOTH ENDS



6) ROTATIONAL RESTRAINT BOTH ENDS

ECCENTRICITY CODES FOR SHORT MEMBERS

RESTRAINT CODES FOR LONG MEMBERS

Design Compression Members

- Allowable compressive stress "Fa" in buckling on the gross cross-sectional area of axially loaded compression members
- Check for local buckling (w/t) ratio

$$F_a = \left[1 - \frac{1}{2}\left(\frac{KL/r}{C_c}\right)^2\right] F_y \qquad \frac{KL}{r} \leq C_c \qquad (3.6\text{-}1)$$

$$F_a = \frac{\pi^2 E}{\left(\frac{KL}{r}\right)^2} \qquad \frac{KL}{r} > C_c \qquad (3.6\text{-}2)$$

$$C_c = \pi \sqrt{\frac{2E}{F_y}} \qquad (3.6\text{-}3)$$

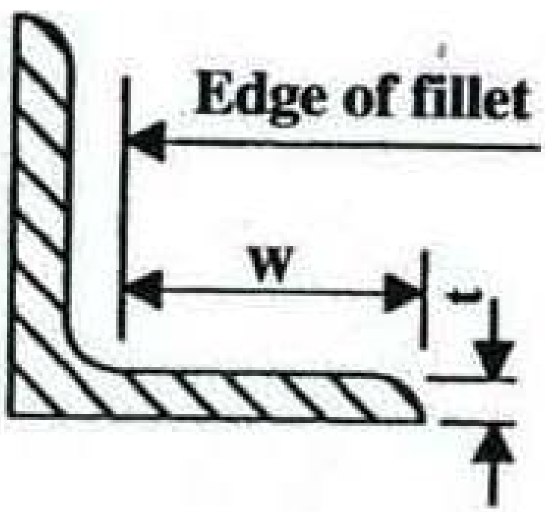
where

F_y = minimum guaranteed yield stress;
E = modulus of elasticity;
L = unbraced length;
r = radius of gyration; and
K = effective length coefficient.

Ref: ASCE 10-97, Sec# 3.6

W/t Ratio

- Max. w/t shall not exceed 25



Ref: ASCE 10-97, Sec# 3.7.3

3.7.3 Determination of F_a

If w/t as defined in Section 3.7.1 exceeds $(w/t)_{\lim}$ given by:

$$\left(\frac{w}{t}\right)\lim = \frac{80\Psi}{\sqrt{F_y}} \qquad (3.7\text{-}1)$$

the design stress F_a shall be the value according to Section 3.6 with F_y in Eqs. 3.6-1 and 3.6-3 replaced with F_{cr} given by:

$$F_{cr} = \left[1.677 - 0.677\frac{w/t}{(w/t)\lim}\right]F_y$$

$$\left(\frac{w}{t}\right)_{\lim} \le \frac{w}{t} \le \frac{144\Psi}{\sqrt{F_y}} \qquad (3.7\text{-}2)$$

$$F_{cr} = \frac{0.0332\pi^2 E}{(w/t)^2} \qquad \frac{w}{t} > \frac{144\Psi}{\sqrt{F_y}} \qquad (3.7\text{-}3)$$

For Eqs. 3.7-1 through 3.7-3, $\Psi = 1$ for F_y in ksi and 2.62 for F_y in MPa.

Design Tension Members

- Depends on full yield stress
- Not on the member length
- L/r limit minimizes member vibration under everyday steady state wind, and reduces the risk of fatigue in the connection.
- Allowable Stress = Fy * An * K

An = Net Area

K = 1 if both legs of the angle connected

= 0.9 if one leg is connected

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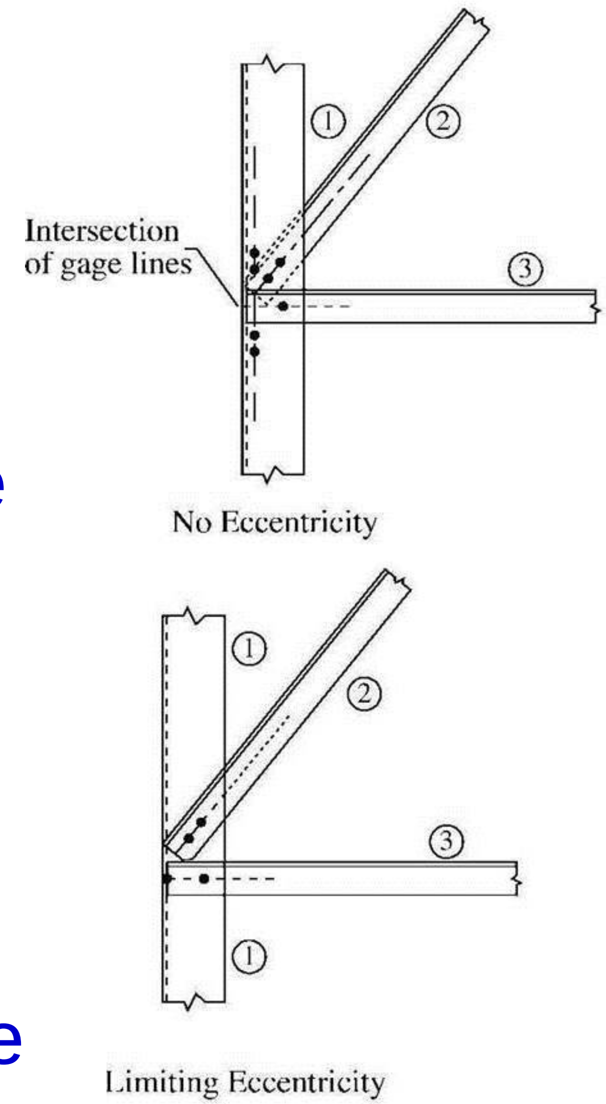
Connections

- Typically use bearing type bolted connections
- Commonly used bolt sizes are
  5/8", 3/4", and 7/8" in diameter.
- Bolts are tightened to a snug tight condition with torque values ranging from 80 to 120 ft-lb
- Load carrying capacity depends on the shear strength of the bolt and the bearing strength of the connected plate.
- Commonly used bolt
  - A394, T0, T1
  - A325, T1

Detailing Considerations

- Bolted connections are detailed to minimize eccentricity as much as possible
- Eccentric connections give rise to a bending moment causing additional shear force in the bolts.
- Sometimes small eccentricities may be unavoidable and should be accounted for in the design.



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Detailing Considerations

Contd...

- Detailing specification should clearly specify the acceptable conditions of eccentricity
- Avoid large gap between the angles
- Minimum size of a member is dictated by the size of the bolt on the connected leg
- Tension members are detailed with draw to facilitate erection.
- Tension members should have at least two bolts on one end to facilitate the draw.

Tower Testing

Why Tower testing?

- Because "It's all in the details".
- The analysis and resulting design are affected by the interpretation of the design standard and its application to the model. Additionally, the performance of the connection is highly dependent on how the tower is detailed.
- Both add uncertainty in which only full-scale testing can provide final verification of the design and detailing assumptions. Any "flaw" in the design or detailing discovered during the test can be mitigated at much less expense than if determined after structures are erected and the line is placed in service.

Tower Testing

Contd…

- Full scale load tests are conducted on new tower designs to verify the adequacy of the tower members and connections to withstand the design loads specified for that structure
- Towers are required to pass the tests at 100% of the ultimate design loads
- Tower tests also provide insight into actual stress distribution in members, fit-up verification and action of the structure in deflected positions
- Develop detailed procedures of tower testing

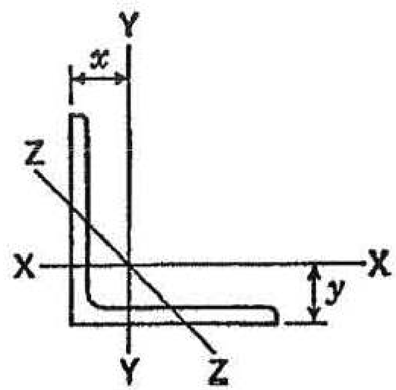
Large Angles – L 10 & L12

Optimum Design solutions for

- Large Angles
- Deadend
- River Crossing

A6/A6M – 12

TABLE A2.7 "L" Shapes (Equal Legs)[A]



Size and Thickness, in.	Weight per Foot, lb	Area, in.²	Size and Thickness, mm	Mass per Metre, kg	Area, mm²
L12 × 12 × 1⅜	105	30.9	L305 × 305 × 34.9	157	19 900
L12 × 12 × 1¼	96.4	28.3	L305 × 305 × 31.8	143	18 300
L12 × 12 × 1⅛	87.2	25.6	L305 × 305 × 28.6	130	16 500
L12 × 12 × 1	77.8	22.9	L305 × 305 × 25.4	116	14 700
L10 × 10 × 1⅜	87.1	25.6	L254 × 254 × 34.9	130	16 500
L10 × 10 × 1¼	79.9	23.5	L254 × 254 × 31.8	119	15 100
L10 × 10 × 1⅛	72.3	21.2	L254 × 254 × 28.6	108	13 700
L10 × 10 × 1	64.7	19.0	L254 × 254 × 25.4	96.2	12 300
L10 × 10 × ⅞	56.9	16.7	L254 × 254 × 22.2	84.6	10 800
L10 × 10 × ¾	49.1	14.4	L254 × 254 × 19.1	73.1	9 310

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Guidelines for Existing Towers

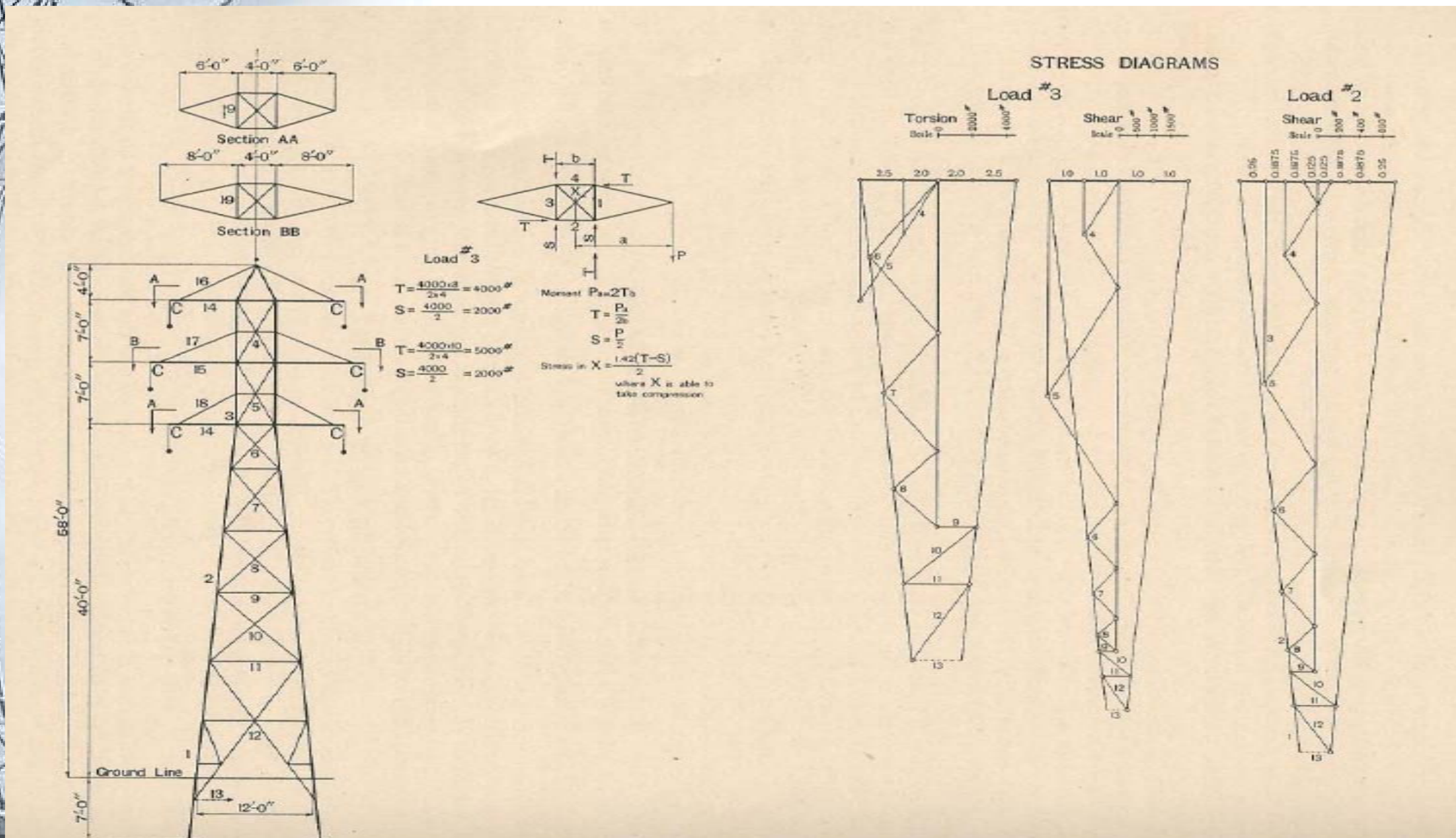
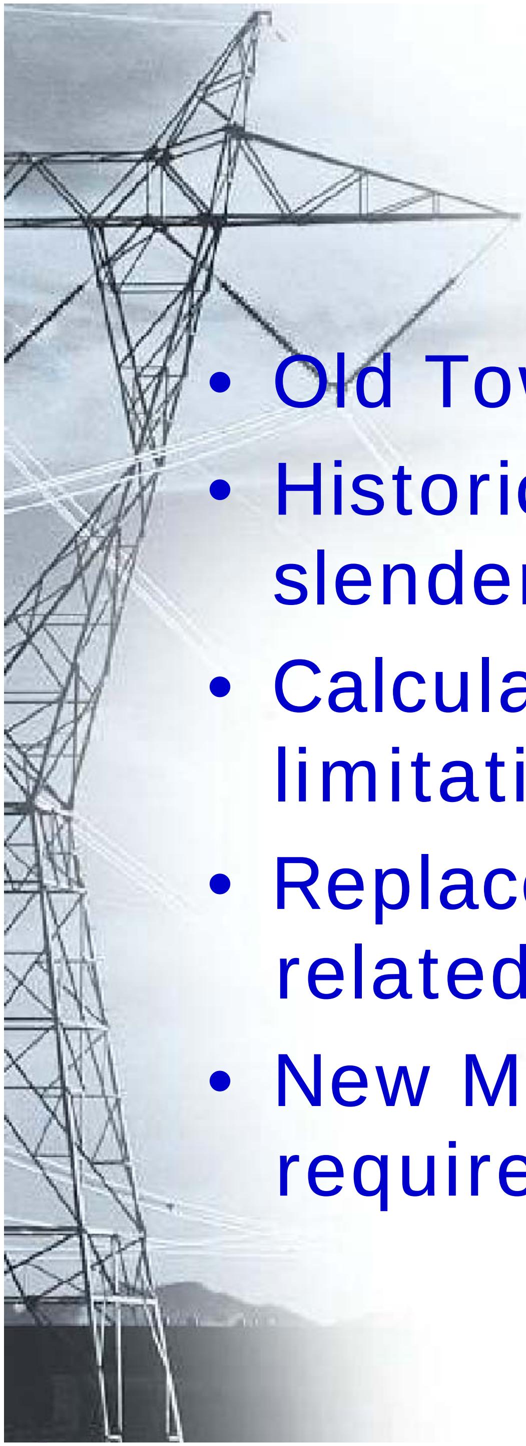


Fig. 16—Stress diagram for double-circuit suspension tower

Introduction

- Upgrading or uprating old Transmission Lines
- Assess structural capability to sustain new loading criteria
- Potential degradation of tower capacity due to aging
- Recommendation to utilize ASCE 10-97 Standard for analysis and design
- Consideration of Historic Performance
- Evaluation of Tower Testing report



Slenderness Ratio

- Old Towers may not meet the L/r limitation
- Historic performance with existing slenderness ratio
- Calculate member Capacity without limitation of L/r ranges
- Replace member for vibration or fatigue related failures
- New Member should meet the ASCE 10-97 requirement

Minimum Distances

- Old Towers may or may not meet min. end distances, center-to center bolt hole spacing, and edge distance
- Utilize sound engineering judgment to determine for acceptable spacing under new loading criteria
- Perform testing to verify connection capacity

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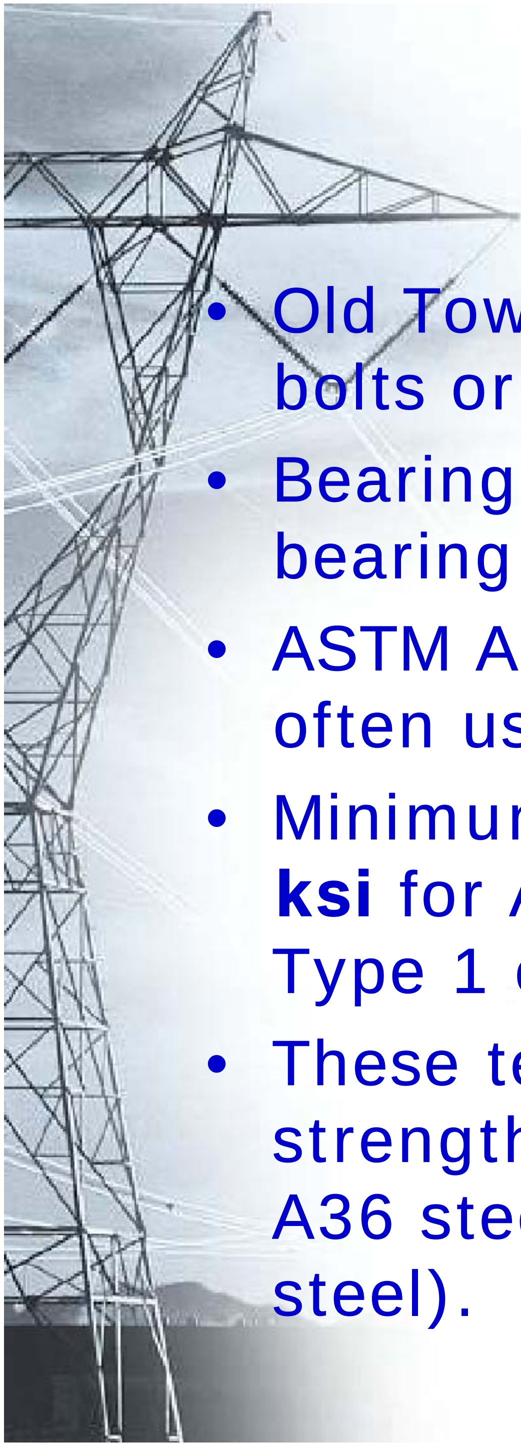
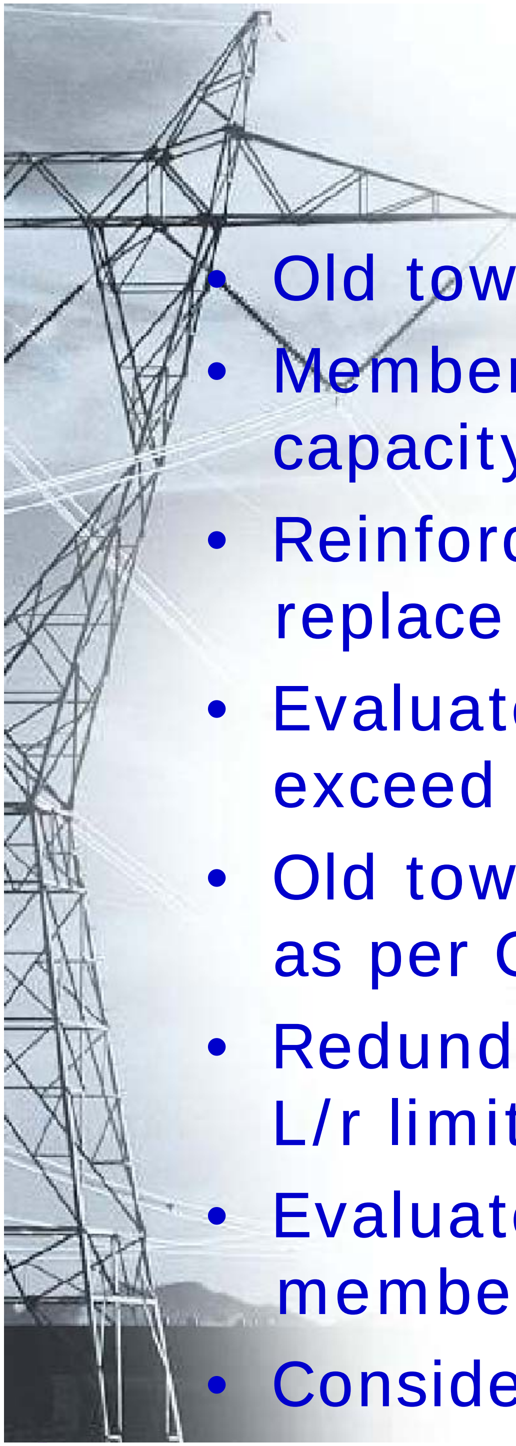
Bolt Shear Capacity

- Old Towers may not include the original assumptions for allowable shear capacity
- Perform test on random sample of bolts as per ASTM F606
- Testing should be completed with threads in shear plane



Bearing Capacity Bolts or Members

- Old Towers did not address bearing capacity of bolts or members
- Bearing Capacity is controlled by the allowable bearing stress of member
- ASTM A394 Type 0 or Type 1 and A325 bolts are often used in towers
- Minimum allowable tensile stress per ASTM is **74 ksi** for A394 Type 0 bolts and **120 ksi** for A394 Type 1 or A325 bolts up to 1” diameter.
- These tensile stress values exceed the tensile strength of the member (i.e. Fu(min) = **58ksi** for A36 steel and Fu(min) = **65 ksi** for A572-50 steel).



Member Use Ratio

- Old towers were designed by graphical method
- Member loads may exceed the calculated design capacity
- Reinforce member by adding bracings, bolts, or replace the member
- Evaluate load case carefully if member use ratio exceed 100%
- Old tower may not consider Man-load requirement as per OSHA guidelines
- Redundant members were designed to meet only L/r limits requirement, not to support lateral load
- Evaluate members for fatigue cracks (large members L/r >> 500)
- Consideration of Historic Performance

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ASTM Materials

- Old towers may not identify the type of steel used
- Use historic information based on AISC guidelines
- AISC 5th Edition, ASTM A7-46 (1937). Tensile strength (Fu) is given as a minimum of 60 ksi to a maximum of 72 ksi. Yield point (Fy) is given as 50% of the tensile strength but in no case less than 33 ksi.
- AISC 6th Edition, ASTM A36-63T steel in 1963. Tensile strength (Fu) values were given as 58 ksi to 80 ksi with a yield point (Fy) of 36 ksi.
- Most likely, Steel used for transmission towers prior to 1960 was A7 steel, between 1960-1970 either A7 or A36, and thereafter a minimum of A36 steel.

Original Compression Formulas

- Old towers were designed using straight-line curves resulting in allowable stresses, which many times are lower for L/r’s less than Cc and greater for L/r’s higher than Cc
- Older designs normally did not use an adjustment factor (K) to modify the allowable compression stress.
- Tension values were also calculated without consideration for block shear and at times without checking bearing capacity.
- Therefore, older towers will often contain members that have a smaller capacity based on the original curves in low L/r ranges.

Case Study

- Tangent Tower
  - Ht = 118ft
  - Basic Tower = 82ft
  - (4) Leg Extn = 36ft
  - No Body Extn
  - Line Angle: 0-10deg
  - Horizontal Span = 3000ft
  - Vertical Span = 4000ft
  - Design Year: 1976
  - Construction Year: 1980
  - Tension Member ONLY design
  - Elev = 5700ft
  - Location: 4/356

Tower Location

Tower: 4/356

Vibration Issues

- Tension ONLY Diagonals
- Vibrate at high frequencies under low steady wind conditions
- L/r value exceed 500
- Vibration in leg members
- No internal diaphragm members at basic towe body level
- No hip bracing members in tower leg

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Fatigue Related Failure

- Fatigue cracks at the bolt holes in redundant members
- Damage in thread of connecting bolts
- Bend in connecting plates (Tower body and leg extension)
- Cracks in foundation

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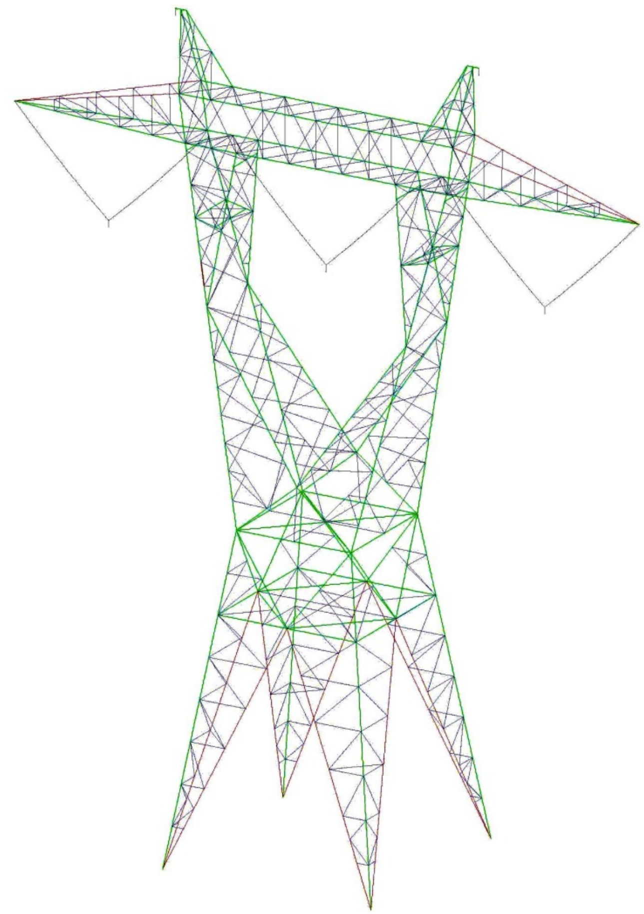
Engineering Analysis

- Performed Analysis using PLS-Tower and latest Tower Design Standard ASCE 10-97
- Used original loading from loading diagram
- Member use ratio exceeded over 100% for several members
- Needed extra bolts to meet shear and bearing capacities
- Originally design using graphical method



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Member Use Ratios

Row #	Angle Label	Group Label	Angle Type	Angle Size	Max. Usage %	Comp. Usage %	Comp. Load Case	Design Comp. Capacity (kips)	Comp. Control Criterion	Tens. Usage %	Tens. Load Case	Design Tension Capacity (kips)	Tension Control Criterion
1	g239Y	b	SAE	1.75X1.75X0.125	**138.76**	138.76	I: TANGENT LIGHT	1.961	L/r	0		5.924	Rupture
2	L039X	b	SAE	1.75X1.75X0.125	**136.97**	136.97	VIb: C&M OUTER	5.7	L/r	0		7.617	Bearing
3	L021-1P	33-BT21	SAE	4X4X0.3125	**119.85**	119.85	I: TANGENT LIGHT	46	Shear	0		46	Shear
4	L021-2P	33-BT21	SAE	4X4X0.3125	**119.34**	119.34	I: TANGENT LIGHT	46	Shear	0		46	Shear
5	L099-1X	b	SAE	1.75X1.75X0.125	**118.9**	0		7.617	Bearing	118.9	I: TANGENT LIGHT	7.617	Bearing
6	L166P	22-B166	SAU	4X3X0.3125	**114.17**	114.17	I: TANGENT LIGHT	55.2	Shear	0		55.2	Shear
7	L039P	b	SAE	1.75X1.75X0.125	**114.14**	114.14	VIa: C&M INNER	5.7	L/r	0		7.617	Bearing
8	g239XY	b	SAE	1.75X1.75X0.125	**113.24**	113.24	I: TANGENT LIGHT	1.961	L/r	1.02	VIb: C&M OUTER	5.924	Rupture
9	L051-1P	03-BT52	SAE	5X5X0.3125	**112.21**	112.21	I: TANGENT LIGHT	92	Shear	0		92	Shear
10	L166Y	22-B166	SAU	4X3X0.3125	**110.1**	110.1	I: TANGENT LIGHT	55.2	Shear	0		55.2	Shear
11	L169Y	23-B169	SAU	3.5X2.5X0.3125	**106.93**	0		46.182	L/r	106.93	I: TANGENT LIGHT	55.2	Shear
12	L169P	23-B169	SAU	3.5X2.5X0.3125	**106.89**	0		46.182	L/r	106.89	I: TANGENT LIGHT	55.2	Shear
13	L004-2P	36-BT4	SAU	3.5X3X0.3125	**104.37**	104.37	VIb: C&M OUTER	18.29	L/r	13	I: TANGENT LIGHT	55.2	Shear
14	L004-1P	36-BT4	SAU	3.5X3X0.3125	**104.31**	104.31	VIb: C&M OUTER	18.012	L/r	12.53	I: TANGENT LIGHT	55.2	Shear
15	L021-2Y	33-BT21	SAE	4X4X0.3125	**103.94**	103.94	I: TANGENT LIGHT	46	Shear	11.36	VIb: C&M OUTER	46	Shear
16	L021-1Y	33-BT21	SAE	4X4X0.3125	**103.94**	103.94	I: TANGENT LIGHT	46	Shear	10.42	VIb: C&M OUTER	46	Shear
17	L120P	86-BT120	SAE	2.5X2.5X0.1875	**102.74**	102.74	I: TANGENT LIGHT	10.342	L/r	10.02	VIb: C&M OUTER	17.773	Rupture
18	FL540220P	04-BB2	SAE	6X6X0.375	**102.47**	102.47	I: TANGENT LIGHT	160.344	L/r	0		218	Net Sect
19	FL540219P	04-BB2	SAE	6X6X0.375	**102.1**	102.1	I: TANGENT LIGHT	160.344	L/r	0		218	Net Sect
20	FL540221P	04-BB2	SAE	6X6X0.375	**102.05**	102.05	I: TANGENT LIGHT	160.344	L/r	0		218	Net Sect
21	L540P	04-BB2	SAE	6X6X0.375	**102.02**	102.02	I: TANGENT LIGHT	160.344	L/r	0		165.6	Shear
22	L001-2P	04-BB2	SAE	6X6X0.375	**101.88**	101.88	I: TANGENT LIGHT	159.56	L/r	0		184	Shear
23	FL540222P	04-BB2	SAE	6X6X0.375	**101.47**	101.47	I: TANGENT LIGHT	160.344	L/r	0		165.6	Shear
24	L001-1P	04-BB2	SAE	6X6X0.375	**100.83**	100.83	I: TANGENT LIGHT	161.117	L/r	0		165.6	Shear
25	FFL5402P	04-BB2	SAE	6X6X0.375	**100.19**	100.19	I: TANGENT LIGHT	160.344	L/r	0		165.6	Shear
26	L091-6X	25-BT92	SAE	4X4X0.25	**100.13**	0		64.4	Shear	100.13	I: TANGENT LIGHT	64.4	Shear

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Remediation Plan

- Performed detailed visual inspection of members
- Performed analysis using actual loadings (site specific location)
- Reviewed historic performance of this tower
- No replacement of members based on member use ratios
- Recommendation for minor modification to mitigate the vibration issues in the diagonals and leg members

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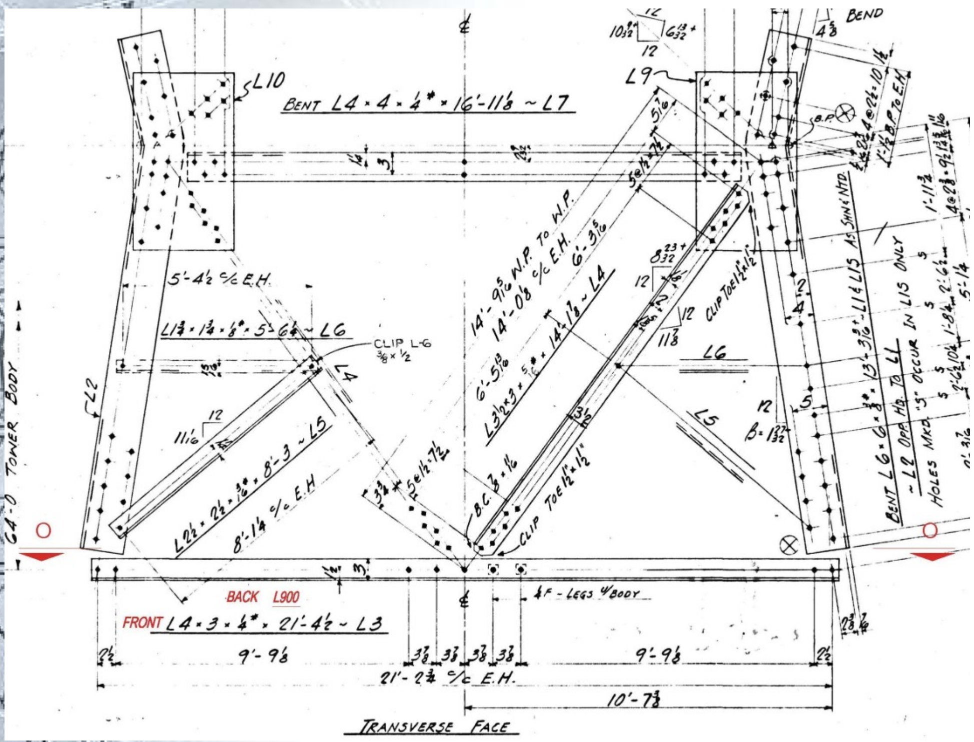
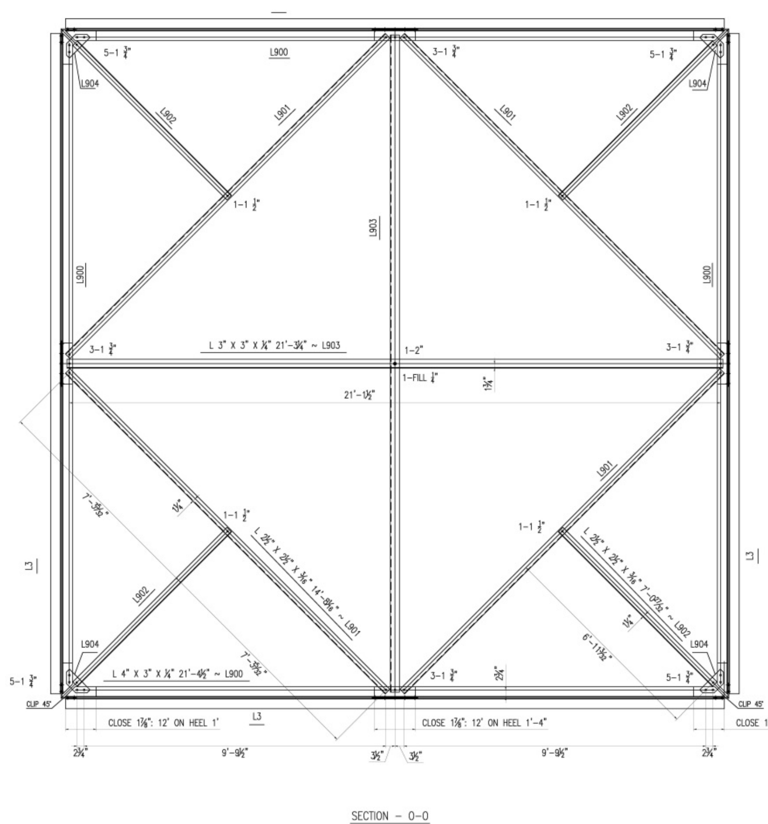
Tower Modification

Added Members in Diaphragm at Basic Body Location





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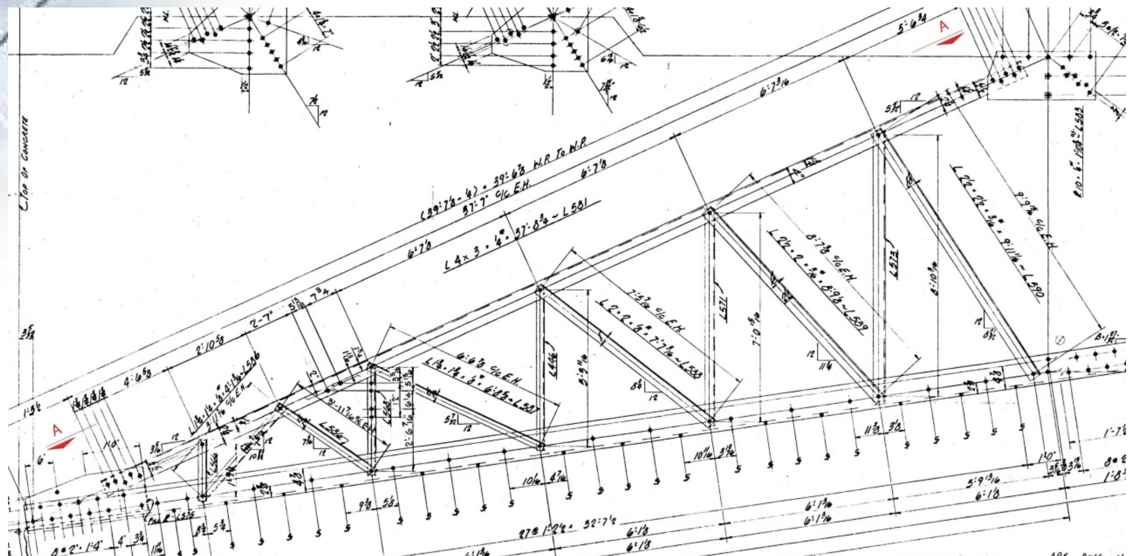
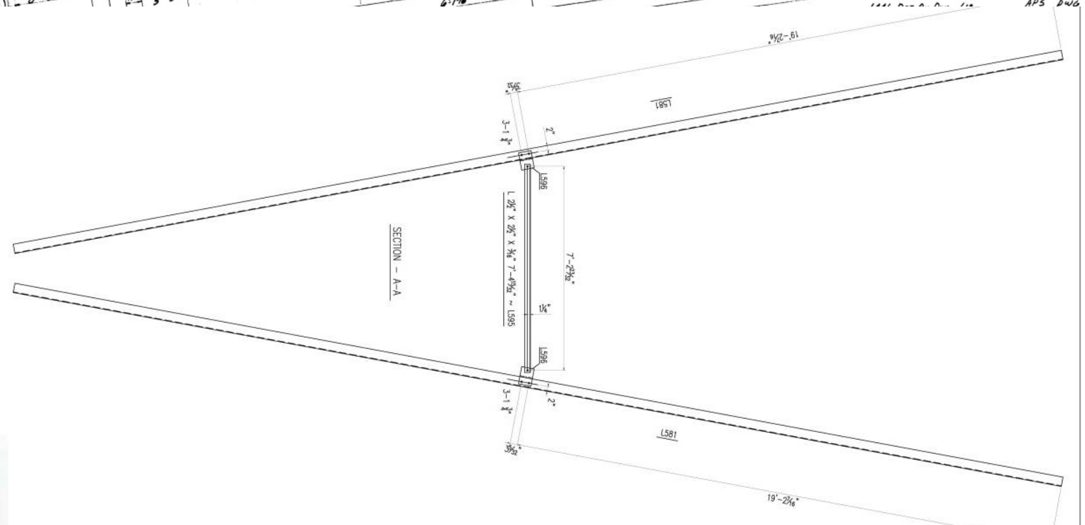
Tower Modification

Added Member in Oblique Face (Hip Bracing) in leg extension





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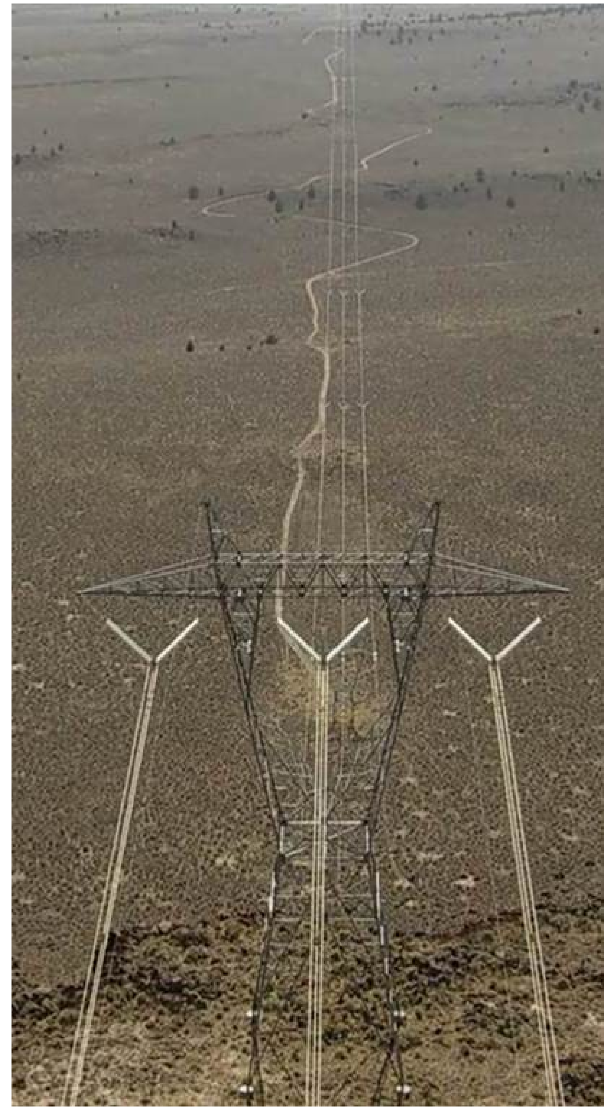
Conclusions

- Older tower design may not meet the requirement of ASCE 10-97 guidelines
- Historical performance must be considered in engineering review process
- Visual inspection is required for fatigue related issues, corrosion of members and bolts, foundation cracks etc.
- Use Tower Test Data to approximate the extra capacity in upgrading/uprating process



Challenges in Performing Engineering Analysis of Existing Lattice Towers!!!

Questions???

Thank You!!!

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CORRELATIVE ANALYSES CONSIDERING DIFFERENT PARAMETERS IN ORDER TO INCREASE RELIABILITY OF ASSET HEALTH ASSESSMENT

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TECHNICAL APPLICATION SPECIALISTS

SUMMARY

Reliable electrical assets are essential for generating, transmitting and distributing reliable energy. Therefore the knowledge of the condition of an asset is extremely important. Offline condition assessment methods are established and used since decades with success. Nevertheless, they give a screenshot of the asset in the moment that the measurements are taken. Despite this, the development of the health condition can only be estimated and the development of incipient faults can be missed.
Nowadays besides offline methods, more comprehensive online monitoring approaches for the assets fleets combined with analytic models and severity analyses are used in order to capture changing conditions in real time and to predict critical situations. For an example, UHF partial discharge monitoring for GIS is established and well accepted for more than 20 years already.
In order to efficiently assess the condition of an asset, the failure mechanism, its associated monitoring parameter(s) and the dedicated analytic model must be known and must be considered in its completeness. Comparing of different parameters is important in order to achieve a holistic view on a specific asset condition.
This paper will give an overview how a severity check by using correlative analyses of different monitored input data, assets and analytic models (e.g. bubbling temperature, TOAN – Transformer Oil analysis and Notification for transformers, Partial Discharge classification for GIS etc.) can improve the reliability of assets health assessments on one hand and giving operators a more easy to understand information instead of providing overwhelming amount of scattered data. It will be shown, how severity analyses principles can be applied for substation equipment on example of transformers, gas insulated and hybrid (breakers and disconnect switches metal encapsulated and SF6 insulated) switchgear.
Furthermore it will be discussed on a practical example of a failure 765kV transformer, how different monitored parameter (in this example online Dissolved Gas Analysis and UHF Partial Discharge monitoring) can complement each other in in order to achieve a higher accuracy in assessing the health of an asset.

KEYWORDS

Severity analyses, online monitoring, health assessment, condition based maintenance

INTRODUCTION

The face of electrical energy production, transmission and distribution has changed significantly over the last few decades. The deregulation of the energy market, along with the privatization of the before public owned utilities, has often lead to more profit oriented enterprises. Furthermore power generation, transmission and distribution were separated in different divisions and privatized separately. Under pressure to increase profits and efficiency, it was popular to outsource maintenance and other technical services. The new created generation, transmission and distribution companies carefully select their investments in new equipment or in the renewal of equipment. Investments are sometimes limited to the replacement of out of date or failed assets. Even failed equipment has not been replaced in some cases, solely due to pure financial reasons. The distribution and transmission companies were especially affected by increasing prices from the major power generation utilities and much lower prices in the retail markets, for example in 2000 and 2001 in California [1]. The result was the weakening of the electrical network, in a number of cases.
Today after overcoming these teething troubles by introducing additional measures (US in 2002 and in the EU in 2007), private investment in the energy sector has led to the development of efficient equipment and efficient methods for operating the assets, assessing the condition of major network components to maintain the ability to deliver electrical energy and to use the equipment till its real end of live. This is today an important driver for the rapid development of innovative condition monitoring.
The change in global energy politics has driven the electrical power industry not only for more efficient solutions, but also to use renewable energy resources, like wind power, geothermic power and solar power. The energy production will become more and more decentralized. Sometimes the

energy will be generated far away from the consumption centers, which is the case in terms of offshore wind farms (e.g. in the North Sea). The decentralized power generation leads into a reconfiguring especially of the transmission network. The electrical energy now needs to be transmitted from the regions, where it is generated to the load centers. The control of the decentralized network will be taken over by Smart Grid technologies. Due to the permanently changing load flows, the impact of failing major equipment can only be analyzed by complex simulation. Even the importance of the key components can change with the change of direction of the load flow, which is difficult to integrate into automated reliability and profitability calculations/ simulations. In this respect the collection of online condition data is essential.
Due to the above described changes in the technical and political environment, condition monitoring of key assets is gaining more and more importance.
Key assets of electrical networks receive, based on the above described circumstances, a high attention in regards to condition assessment. Offline condition assessment methods are established and used since decades with success. Nevertheless, they give a screenshot of the asset in the moment that the measurements are taken. Despite this, the development of the health condition can only be estimated and the development of incipient faults can be missed.
Introducing online monitoring in the past most often was just limited to some independent parameters. Users struggled accessing the true overall condition of an asset. Typical statements were and still are "I got an alarm, but what that does it mean to my asset?" Confusions prevailed over clear decisions in lots of cases. "False Alarms" leaded and lead in not trusting installed monitoring solutions. A common opinion was and still is that always the help of experts in that field is needed.
Nowadays more comprehensive online monitoring approaches for assets combined with analytic models and severity analyzes are used in order to capture changing conditions in real time and to predict critical situations. The implementation of procedures for operators and maintenance in regards to asset monitoring are becoming more common.
Correlative analysis are gaining more and more importance as it enables the user to do severity analyses by using different parameters which are supporting or contradicting each other in its individual asset condition prediction. In order to efficiently assess the condition of an asset, the failure mechanism, its associated monitoring parameter(s) and the dedicated analytic model must be known and must be considered in its completeness.

ANALYTIC MODELS - GENERATING INFORMATION INSTEAD OF DATA

The knowledge of the failure statistics/ past experience of a certain asset as well as the understanding of failure mechanisms combined with the criticality are essential to choose the right parameter for an assessment and to build up analytic models. Most of the time today, asset assessment will be related to preventing failures and Condition Based Maintenance (CBM). Online condition assessment could be also a powerful tool for asset operation. The prediction of a certain load condition and the risk status of electrical assets can then be used for dynamic loading. Once the pressure on the owners regarding financial efficiency increases dynamic loading becomes more and more important.
Presenting "only" data can mislead to poor maintenance decisions and unnecessary interventions, which usually have the potential to introduce new failures. Figure 1 shows this scattered data approach.

A practical example could be partial discharge (PD) measured in a Hybrid breaker installation with UHF sensors and with PD active only in one of them. Considering the detected PD solely, it could lead to the decision to open up the Hybrid installation and trying to find the failure. Considering also the fact, that gas filled bushings are used (low capacitance/ almost no low pass behavior) it would be necessary to contemplate the possibility that UHF can enter from the outside. PD appearance and disappearance for longer periods, mostly related to climatic conditions, will give a clear sign of external discharges (e.g., surface discharges on the silicon surface of the bushings). At first instance the example seems very basic, but in reality it is one of most common false decisions (valid also for GIS overhead line bays).

Figure 1: Scattered data approach

Besides capturing reliable data from the chosen parameters, relevant information needs to be extracted. Using a PD example it would mean, that PD impulses must be related to its position in phase of the line voltage, which then allow to combine the single impulses to different pattern types (PRPD pattern – phase resolved partial discharge pattern; 3D pattern; point of wave etc.). Adding the time of occurrence will also give additional information for the analysis of the PD. Comparing for example additionally the time of arrival or/and amplitudes of the same PD impulses at different sensors will give further useful information about the origin of the PD. Figure 2 shows a possible approach for information extraction out of collected data. Figure 3 shows how the collected data will be analyzed (for example by simple logic or artificial neuronal network approaches, fuzzy logic etc.) and further verified with the help of other related data (e.g. PD and Dissolved Gas Analyses (DGA) at transformers.

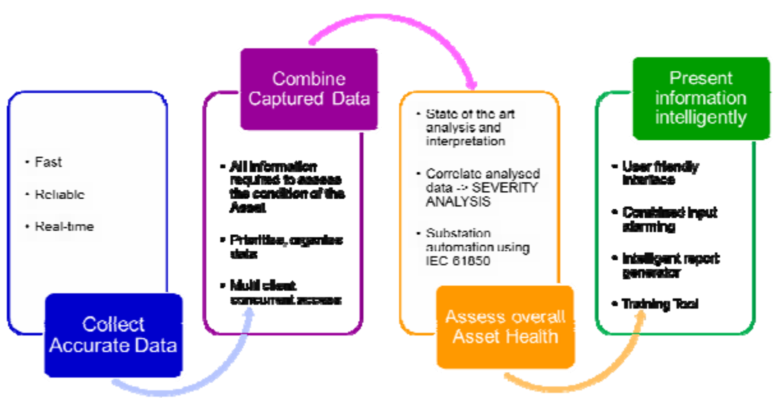

Figure 2: Information extraction block diagram

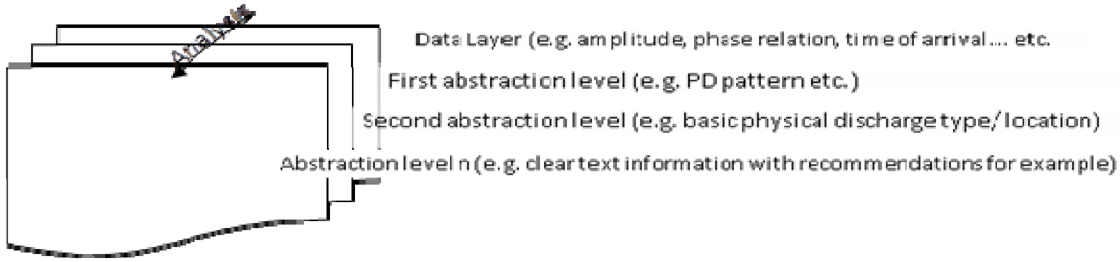

Figure 1: Diagram data abstraction level

The abstraction level can be arbitrary continued.
Figure **2** shows the abstraction level at network level at the left and substation level at the right.

Figure 2: Information abstraction to network and substation level overview

Complementary to analyzing the data of a certain parameter, different parameters should be correlated to each other, including online and offline data, as well as data from different sources, e.g., SCADA systems, periodical visual checks, load data etc. Automated correlation of data can be done for online data. Offline available data needs to be correlated manually or taken into an online tool which is able to marry online and offline data. Further on, some examples are discussed regarding asset components, failure mechanisms, what parameter have the ability to detect them in an early stage and how different parameters/analytical models can complement each other to identify the possible incipient fault.

FAILURE STATISTICS, ASSET COMPONENTS, AND FAILURE MECHANISMS

Failure Statistics

The latest transformer reliability study published in [2] shows the windings with 45% as the major cause of failing transformers, followed by tap changers with 26%, bushings with 17% and lead exits with 7%. All other major components of transformers are playing a minor role (see **Error! Reference source not found.**). The overall transformer failure rate according to [2] is reported with 0.44%, while transformers for Extra High Voltage (EHV) and the lower end of high voltage are showing a failure rate around 1%.

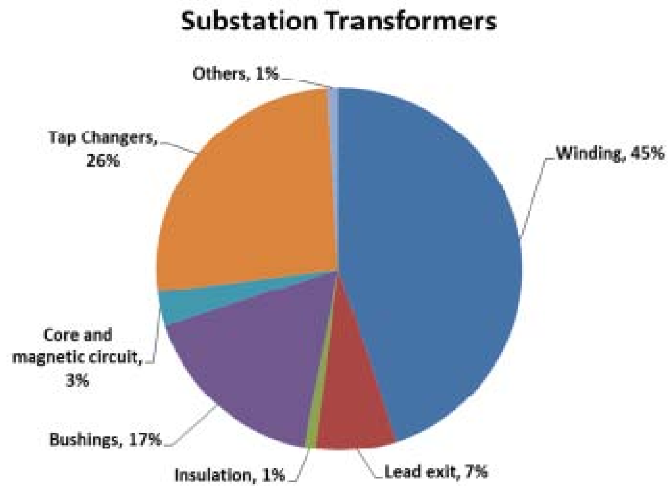

Figure 5: Latest Transformer Major Failure Statistic [2]

Asset Components

All transformer incipient faults will somehow result in the generation of detectable signs of its presence. These signs could be chemical, electrical, optical or acoustical nature, but most of the time a combination of these. Here some selection of possible faults, assigned to the related component will be described.

Transformer Main tank

Of main concern in regards to the transformer main tank is the dielectric integrity of the liquid, bulk and paper insulation, as well as accelerated aging by local and general overheating and moisture. This is tightly connected with the danger of bubble creation at high moisture and dissolved gas content combined with high temperatures. Moisture and overheating will accelerate the aging of the cellulose and this will again result in creating decomposition products of the cellulose like Furan and water again, which will accelerate the aging even more. At a certain point, the paper insulation will lose its insulation strength till it will not withstand any mechanical stress and make the transformer fail.
Loose parts, sharp edges, delamination's of bulk insulation, conductive particles in oil, bad contacts and gas bubbles in oil are having the potential to weaken the liquid and solid insulation system and to create PD and arcing. Strong discharges as result of these defects will decompose the oil/ the paper insulation and/or erode the conductive material.
Further failure can be caused by local overheating and burnings due to bad contacts, by circulating core ground current or bad or missing connections from core to ground and from magnetic or electric screens.

Transformer Load Tap Changer (LTC)

LTC failures account for a significant portion of transformer failures. LTC contact wear occurs as the LTC operates to maintain a desired voltage with varying loads. This mechanical erosion is a normal operating characteristic, but the rate can be accelerated by improper application, faulty installation, and overloads. If an excessive wear situation is not corrected, the contacts may burn open or weld together. Monitoring a combination of parameters suitable for a particular LTC design can help avoid such failures. LTC failures can be combinations of mechanical, electrical, or thermal faults. Failures that are mechanical in nature include failures of springs, bearings, shafts, motors, and drive mechanisms. Faults that are electrical in nature and can result in a detectable thermal condition can be attributed to coking of contacts, burning of contacts and/or transition resistors, and insulation problems [5].

Transformer cooling system

The main concern in regards to the cooling system of a transformer is to ensure the oil and air flow through the radiators/coolers is always guarantied. This can be done by natural convection for smaller transformers or in case of bigger power transformers by a forced cooling system. In oil forced cooling system pumps are used to circulate the oil through the radiators/coolers and fans are responsible to circulate the air through the radiator fins and cooler rips to take the heat away. More complex systems are using water to cool the oil. In that case pumps are also circulating the water. If the cooling system is disturbed by mal functions of fans or pumps the oil and therewith the transformer cannot be cooled down in an appropriate way so that it can lead to an overheating and failing of the transformer.

Transformer bushings

Bushings are used to transport the electrical energy into and out of a transformer from and into an electrical network. For higher voltages mainly above 36kV (for generator step up units also the high current bushings for 24kV and 36kV) capacitor bushings are used. The major failure causes for bushings are moisture, partial breakdowns due to over voltages or pre-deterioration due to partial discharges or leakages in case of oil impregnated paper bushings (OIP).

Looking into catastrophic failures, according to [3], bushings are in 70% of the cases the cause, there are other components leading the transformer to fail but with less risk of a catastrophic failure.

Table 2: Transformer Failure statistic [2]

	HIGHEST SYSTEM VOLTAGE [kV]					
FAILURES & POPULATION INFORMATION	69 kV < 100	100 kV < 200	200 kV < 300	300 kV < 500	kV 700	All
Failures	145	212	163	154	11	685
Transformer -Years	15220	48994	47473	41569	959	156186
FAILURE RATE/ YEAR	0.95%	0.43%	0.34%	0.37%	1.15%	0.44%

GIS/ Hybrid Failure mechanism

The three major failure groups of concern for switchgear are dielectric failures, mechanical failures and SF6 leakages.
Dielectric failures mainly happen either under steady state conditions or as a result of a switching operation. Failures during steady state condition are mainly developing over time, before it comes to a total breakdown of the insulation. A breakdown at steady state condition can also be caused by a mechanical operation, where for example something got loose or damaged and then developed over time to a major failure. Fee moving particles could be activated due to mechanical impact during switching operations. They can move into a high field area, even if they are resting in a low field region. Discharges due to loose parts or inside of solid insulation can erode the material over time and develop to a dielectric breakdown. Breakdowns as the result of a switching operation can be caused by protrusion type of defects (sharp edges, upright standing particles, particles on spacers). Increased PD activity after breaking operations can be an early sign of contact wear of the breaker.
Oil leakages can cause over time frequent pump motor starts and may lead to phase disagreement. Defective close or trip coils preventing breakers to operate. Wear of the mechanical part of the breaking mechanism will change the switching behavior in terms of time and/or in terms of velocity. A few operations with fault currents will result in an accelerated aging. Especially in very frequent switched installations like Hydro Power storage plants where a breaker will be operated twice a day and sees roughly 10 times more often switching operations. High switching frequencies will also affect breakers and capacitor banks.
Considering switching transients and very fast transients (VFT – due to disconnector switching in mainly GIS installation) the interface and accessory and equipment needs also to be considered.

GIS failure distribution

Figures 6 and 7 are presenting the major and minor failure distribution for GIS [4]. The overall failure rate is reported as 0.37 failures per 100 Circuit- breaker- bay years. The two main contributors to major failures are mechanical and dielectrical failures, minor failures gas leakages and mechanical problems play an important role.

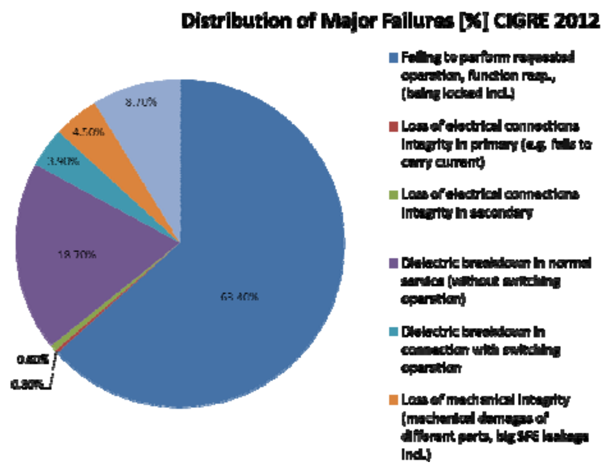

Figure 6: Major Failure distribution [4]

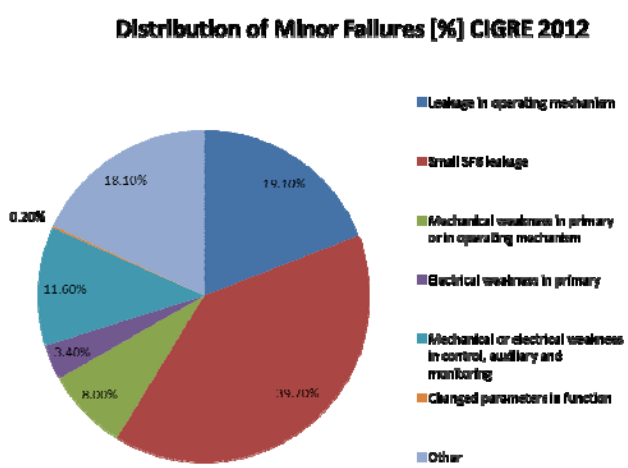

Figure **7**: Minor Failure distribution [4]

ANALYTICS AND CORRELATIVE ANALYSES

Analytics concerns about a certain parameter as correlative analyses combines information from different parameters and from different sources. Both are using abstractions algorithms (from very simple logic/ calculation to very sophisticated methods like artificial neuronal networks. The aim is to extract information. In the bubbling temperature model for example the hotspot temperature is used to determine the temperature at which the gas bubble generation starts. To enable this calculation, a set of different parameters need to be known, as the hot spot temperature, the moisture in oil, the gas content in oil, the pressure at the hot spot, the temperature of the oil at the moisture sensor and the ambient temperature.

In general it will be distinguished between diagnostic tools based on single parameters and parameter sets like Duval triangle in terms of DGA and localization techniques for PD and analytic models like bubbling temperature, TOAN (Transformer Oil Analysis and Notification – developed by Arizona Public Services), cooler efficiency calculation, remaining thermal life modelling, automated PD classification, etc. Some of the models found already its way into the international standards and recommendations like for example in [6].

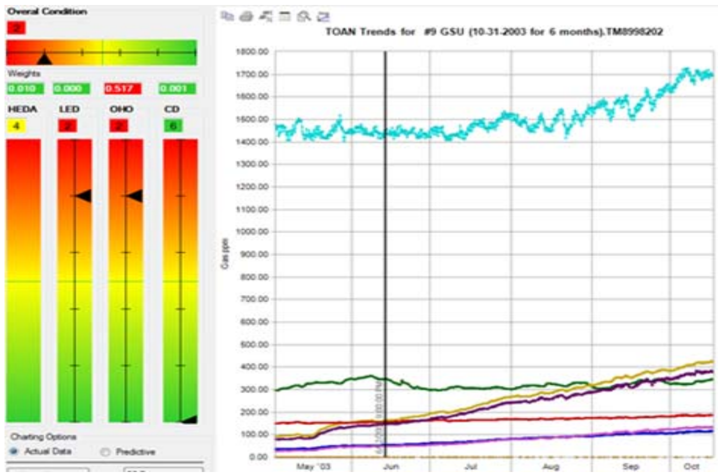

Figure 4: TOAN as an example for an analytic tool

The difference between analytics and diagnostic tools is that analytic tools give an indication about the condition of an asset like a transformer and diagnostic tools are used to identify the upcoming fault detected by the analytics. Diagnostic tools usually are not allowing a good and bad decision. They are focusing on the type of defect, on the location of the defect etc. in order to support the Condition based Maintenance (CBM) decision making process.
Correlative analyses can use one or several relevant parameter or even results out of the analytic to confirm or to not confirm a certain assessment. That will increase the confidence in the result drastically. Table 3 shows an example of correlative analyses for the magnetic circuit considering different parameters.

Table 1: Magnetic circuit correlative analyses

	Component	Failure mechanisms	Measured signals/ parameters	Analytical model	Confirmation	Detection time
Magnetic Circuit	Core ground lead	Loss of core ground	Hydrogen or multi-gas	DGA Model	1	Hours
	Magnetic shield	Unintentional core and shield grounds create problems and discharges	Core ground current	Core Ground Current Model	2	Days
			Gas accumulation relay	Gas Accumulation Rate Model	3	Real time
			Core hotspot (Fiber) Temperature	Thermal Model	4	Hours
			PD	PD Model	5	Real Time

In the above example there are 5 different analytic models available to, which can confirm or not confirm a certain condition. For each of the models different input parameters need to be gathered and each of the models/ parameters has its detection time. Similar examples can be done for different kind of failure mechanism in the transformer main tank, LTC's, bushings, cooling systems etc. Regarding the importance of that particular transformer and its history a decision can be made on what failures need to be covered.

PRACTICAL EXAMPLE

A 765kV single phase autotransformer equipped with the typical EHV package, DGA, bushing monitoring and temperature monitoring. Furthermore legacy data was available and additionally 6 UHF PD sensors were installed and connected to a permanent monitoring system. The transformer had been 3 month in service and experienced a catastrophic failure. DGA and bushing monitor did not alarm, but the PD monitor showed strong PD activity 8 hours before the failure occurred. This shows that correlative analyses not only confirm or not confirm each other, but also can complement each other as shown in this example, covering the time period, where for example one method would be to slow (like DGA due to the time needed to distribute the generated gas) [7].

CONCLUSION

The power industry today demands, besides the conventional transformer gauges and well established online DGA applications a more comprehensive monitoring approach in order to implement CBM principles, to using transformers more efficiently and more optimized, as well as detecting incipient fault already in an early stage.

The demand for analytic models, which allows users to make reliable decisions about their assets, is exponentially increasing. Using correlative analyses contributes to increase the confidence about transformer health assessments and will allow the use of complementary models, which will be able to cover the limitation of the other.

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Direct Embed Weathered Steel Floating Poles

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Direct Embed Weathered Steel Floating Poles

David Hancock, P.E.

Introduction

It is very common these days for weathered steel (Cor-Ten) poles to be utilized on transmission projects. These poles are used for various reasons including but not limited to lower cost and/or aesthetics. Some people believe the rust brown color of these structures blend in nicely in rural areas where there are trees and other vegetation. Often these poles are used along with a direct embedded foundation type. One issue with these poles being used in conjunction with this type of foundation is that they can float under certain conditions. These conditions include wet holes and/or wet concrete backfill construction. The poles must be hermetically sealed in order to guarantee excessive corrosion does not occur due to moisture collecting inside the pole. Since the pole is completely sealed when submerged in a fluid it will become buoyant. The buoyant forces on the embedded section of pole can easily exceed the weight of the section as well as any other externally applied forces. Once this occurs, the pole section will lift out of the hole (or float).

This paper reveals a real 345-kV transmission project in which this “floating pole” issue actually occurred and had to be solved in construction after the poles were already fabricated and delivered. This project was located in the panhandle and northern part of Texas and was built as part of the Competitive Renewable Energy Zones (CREZ) program. The total mileage of this transmission line project is 235 miles. The following paragraphs will describe the structure type, material, and construction conditions which lead to this issue. Some basic theory of why this happened is also discussed in order to shed some light on just how significate the forces on the structures can be. And last but not least a brief discussion of what solutions might help prevent or mitigate this issue on future projects.

Structure Description

The 345-kV double circuit tangent structures selected for this project utilized weathered steel poles (Cor-Ten), versus galvanized steel poles. These weathered steel poles must be completely sealed in order to keep moisture from building up on the inside of the structure and causing excessive corrosion which could compromise the integrity of the structure. The average size tangent structure for this project was 120-ft above ground with a base section diameter of 58-in to 63-in. The embedded portion of the base section was not tapered in order to minimize the diameter of the hole and in turn the volume of concrete backfill required. This non tapered base section also saved a little on total structure weight. The initial foundation design for these structures had the base section of the pole embedded into augured holes 30-ft to 40-ft deep at 6-ft to 7-ft diameter on average.

Floating Poles in Construction

Before construction started the concern of floating poles was discussed amongst the engineering and construction teams. However, the contractor had dealt with this in the past and felt that using dead-men (large concrete blocks) hold downs and such methods would be sufficient (See Figure 1). As construction commenced, the first of the embedded poles where installed in completely dry holes and the method of holding down the embedded sections seemed to work fairly well. Shortly after the start of construction the transmission line entered an area where the water table was present within the depth of the hole. Once the foundations were drilled in this area the holes immediately filled up partially with water. Every effort was taken to minimize the water in the hole but regardless of this it created a situation that made it very difficult, if not impossible, to keep the structure base seated firmly on the bottom of the hole and to keep water and/or fluid concrete from getting under the structure base. Although the floating pole issue was not always constrained to just the locations were water was present in the hole, it was by far the area that caused the most problems. The force on some of the base sections was so large that there were actually instances where the pole base rose out of the hole abruptly in which the concrete dead-man blocks and any other equipment that may have been attached were lifted off the ground.

Figure 1. Photo of concrete blocks used as hold-downs.

Theory Behind Floating Poles

The root of the problem lies in the theory of buoyancy. Buoyancy is the resultant force on an object which is submerged in a fluid. The simple equation for the resultant force on an object submerged in a fluid is the weight of the volume of fluid being displaced minus the actual weight of the object. In fact, what this really boils down to is the summations of fluid pressures all around the object which sums to a resultant force on the object. In the case of an embedded steel pole the wet concrete mix along with any water that may be present in the hole is the fluid we will discuss in this paper. There are no true studies or experiments that could be found that calculated the exact fluid density that should be used to calculate fresh (wet) concrete buoyant pressures; however, the common value for the weight of wet concrete of 145 pounds per cubic feet (pcf) will be used in this paper. As mentioned in the previous paragraphs the section of pole that is being submerged in the hole is not tapered. This means that the fluid pressure around the perimeter face of the pole all cancel out leading to no resultant force. The top of the section extends well above the ground level therefore there is no fluid pressure force downward on the pole. The only place for the fluid pressure to apply force on the structure is the bottom of the base section (bearing plate). Without this pressure on the bearing plate the resultant buoyancy force on the structure would be zero. Assuming the concrete mixture has no shear strength to transfer this force from the pole to the soil

(Arching), the only other force resisting this buoyancy force would be the weight of the base section and any other hold downs or weights attached to the structure.

To give an example of the forces that were encountered in the field the average base section that was installed on this project was used (See Figure 2). This section weighed approximately 20,000-lb and has a bearing plate area of approximately 20-ft^2, or a diameter of 5-ft. At an embedment of 35-ft this would mean that the force on the base bottom would be:

$$F = \text{Area} * \text{Depth} * \text{Fluid Density}$$

$$F = 20\text{-ft}^2 * 35\text{-ft} * 145\text{-pcf} = 101{,}500\text{-lb}$$

Subtracting out the weight of the section leaves an additional 81,500 lbs. that must be resisted in some fashion to keep the pole from lifting out of the hole.

Initial Attempted Solution

Four concrete blocks were used to attempt to hold down these pole base sections. These blocks weighed in the order of 4000 to 5000 lb. each. In most of the dry holes the poles weight, plus the force being added by the blocks, was enough to seal the bottom of the base into the soil which in turn would keep the fluid concrete mix from getting underneath. This allowed the poles to be installed without any significant force pushing the poles up or out of plumb. However, as mentioned earlier, the problem came when the holes were below the water table. Two things occurred in this scenario. First, because of the water in the hole, the contractor was not able to get the pole base to seal firmly against the bottom of the hole and therefore not able to keep fluid (water and concrete) from getting under the pole base. Second, because the water table was above the bottom of the hole the fluid pressure was always present regardless of how much force was put on the pole base. In either case, once the concrete was poured to a level in which the pressure on the base created a force larger than the section weight, Arching, and weight of the concrete blocks, the pole started to float. In at least one case the Arching in the concrete mix held the base section down temporarily but as the fluid concrete level approached the top of the hole the bond between the pole and concrete broke and the pole abruptly came out of the hole several feet lifting the blocks off the ground.

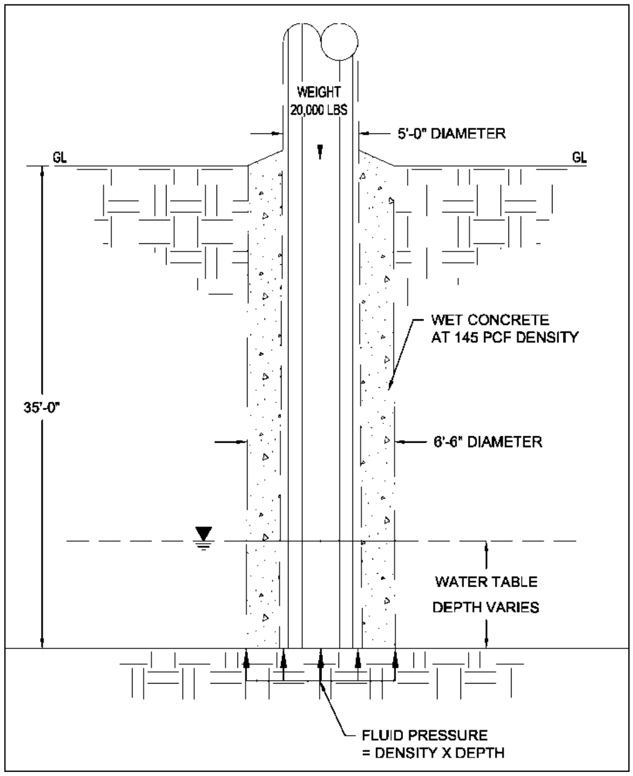

Figure 2. Sketch of embedded pole section.

Final Solution

This quickly became a problem that had to be solved in order for construction of the line to continue successfully and safely. The first solution to be explored was to drill or cut holes at the base of the pole. This solution was quickly dismissed due to it voiding the warranty of the structures not to mention the potential long term damage that could be cause by moisture building up inside the pole. Because the poles were already fabricated and on site a construction solution had to be figured out. The solution that was finally implemented in the areas where water was encountered is as follows. The hole was first over excavated by approximately 1-ft in diameter and 2-ft in depth. Next concrete was poured into the hole to a depth of approximately 2-ft until the original desired hole depth was obtained. Before this concrete cured too much and was still soft a 1-ft diameter smaller corrugated pipe was installed into the hole and pushed into the concrete at the bottom of the hole. This created a sealed bottom surface of the hole. In addition, water was not able to enter the inside of the corrugated pipe which the pole would eventually be installed. Once the concrete cured for a few hours the annulus between the corrugated pipe and outside of the hole was filled with concrete. The inside of the pipe was cleaned thoroughly with all water removed. The pole base section was then installed and tied down, just as in the dry hole case. This created a firm seal of the base of the pole to the flat, not fully cured, surface of the concrete base. Concrete was then poured in the annulus between the pole and the corrugated pipe. Fluid in the concrete backfill could not get under the bearing plate of the pole because the pole base was firmly sealed to the concrete base. Since there was no fluid under the bearing plate no pressure existed and therefore no resultant load pushing the pole upward. Figure 3 shows a picture of this method being performed in the field. This may not have been the only (or even best) solution, however, it allowed construction to continue and ultimately complete a very successful project. Although the project was successful, this solution did come with a substantial cost difference compared to the standard foundation design. Fortunately there were only a small percentage of foundations that encountered water on this project. Had this project been located in a different region with a higher water table this could have been a much larger and more expensive problem.

Figure 3. Revised construction method.

Other Solutions

After this solution was implemented for wet holes the installation of the embedded pole base sections continued with little to no issues. Although a solution was found and the project ended up being successful, it would have been best to mitigate this issue in advance of pole fabrication and construction to save on cost. If weathered steel is the desired or only option there are several ways this issue could be mitigated if not dismissed all together. One thing that would have helped (not dismissed) the issue would have been to use tapered base sections versus non-tapered. The pressure from the concrete pushing down on the tapered section would have helped counteract some of the forces pushing the pole base upward. Another solution would have been to use galvanized base sections which are not sealed with the remaining sections above ground being weathered steel. A potential solution very similar to the galvanized embedded section just mentioned would be to utilize a concrete pole base with weathered steel attached above grade. This option is commonly called a “hybrid” pole. Yet another option would be to not use embedded tangent structures at all but instead use base plated poles with drilled shaft foundations. If the choice of weathered steel is due to having brownish structures one last option may be to paint or coat the structures instead.

Although there are several options of structure types and/or combinations that can help mitigate this issue, it is possible if designed and planned properly, to mitigate this issue in construction. This solution, as see in the example in the previous section, can be more expensive but is possible. The key is to plan ahead of time so that all parties (engineers, contractors, clients, etc.) not only have input into the decision but also know the risks and what to expect.

Conclusion

Embedded weathering steel poles can be a more aesthetic and possibly slightly cheaper option for transmission line structures in certain areas. However, during the planning phase of a project, when these types of structures are being considered, it is highly recommended that the pros and cons be weighed before making a final decision on how to mitigate the floating pole problem. If ignored, this problem can endanger the budget and schedule of a project during construction. More importantly it can be create a safety hazard. Being knowledgeable about this issue and planning for it at the beginning of a project will maximize the probability and safe execution of a successful project using these types of structures.

Evolution of Bushing Monitoring Methods

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48th Annual Transmission and Substation Design and Operation Symposium

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Introduction:

This paper focuses on the most common bushing monitoring and testing methods used in the United States and the people and organizations that developed the different technologies. The paper discusses the author's experiences with testing and operating these systems and other utilities or groups that the author is aware of, and almost certainly has overlooked development or testing by others that are not known to the author.

Background:

George Westinghouse obtained the US rights to an English patent for an AC distribution system in 1886 and formed the Westinghouse Electric Company to manufacture and promote the use of single-phase AC power equipment. In 1886, William Stanley, Westinghouse's chief electrical engineer, was the first in the US to successfully demonstrate the use of the transformer in an alternating current system to provide electric lights for the Town of Great Barrington, Massachusetts (see Figure 1). In 1888, Westinghouse purchased Nikola Tesla's patents on induction motors and polyphase AC power and continued the development of generators and transformers.

Figure 1 - Great Barrington Massachusetts Transformer - 1886

The commissioning of the Niagara Falls Generating Plant by the Niagara Falls Power Company in 1895 lead to a rapid expansion in AC power systems using the new AC technology that had been developed by Nikola Tesla and George Westinghouse. The plant was constructed with 10 generators and produced a total output of 37.3 MW at 10kV and 25 Hz (see Figure 2). Switchyard transformers were also built to step up the voltage to 20kV for transmission to remote areas and the substations on the other ends of those lines all needed transformers too.   By 1890, Westinghouse had standardized on 60 Hz and this became the standard for electric utility power in the US and many parts of the world.

Figure 2 – 1.875 MVA, 2 kV/10 kV original 3-phase step-up transformers at the Niagara Plant (Photo from "Transformers at Niagara Falls" by Works of the Westinghouse Electric & Manufacturing Company)

The bushings for these early transformers were all simple bulk-type bushings, constructed with an insulator around a central conductor. The only monitoring required for these bushings was an occasional visual inspection to see if the insulator material was damaged or broken.

As the need for higher voltage transmission developed, the original bulk-type bushings became impractical due to the required physical dimensions for electrical clearances. Capacitive graded oil-filled condenser type bushings were developed to meet this need in 1908 and permitted transformer voltages to increase up to 69kV. Further refinements in bushing designs continued to expand the limits of available transformer and bushing voltages to the levels we have today.

Early Tests:

But the dimensional benefits of condenser type bushings came with some trade-offs. They were reliable components, but condensers could occasionally fail and cause catastrophic transformer failures. Tests were developed in the first part of the 20th century by transformer and bushing manufacturers like Westinghouse and General Electric to monitor the condition of transformer insulation systems as well as bushing condenser condition to detect deterioration or insulation breakdown.

Standardized Off-Line Tests:

In 1934, Frank C. Doble was awarded a patent US 1.945,263 titled Apparatus for Testing Insulating Values [1]. The patent contained several sketches and descriptions, but just one basic formula, PF=W/VI. This type of testing eventually became widely utilized and by the 70's was used by most large electric utilities for the off-line testing the insulation systems in bushings, transformers and other equipment. Off line testing provided a snapshot of bushing condition on a periodic schedule which could often detect slowly evolving problems, but when tests were only performed every 3-5 years, problems could develop and failures could occur between scheduled tests. While off-line testing is the most widely employed bushing monitoring method today, users sought improvements to produce better visibility and improve power system reliability.

First On-Line Bushing Tests:

In the 1967, P. M. Svi and his colleagues in the former Soviet Union developed a monitoring system and method to test transformer bushings on energized transformers [2][3]. The method connected the three phases of a set of bushings together in an effective wye connection and measured the magnitude of the resulting neutral current. This method is referred to as the Sum-of-three currents method or the Sum-of-currents method. The systems were initially installed on several 500 kV transformers and credited for substantially reducing the failure rates. It has proven to be a reliable system and there are many more such systems in-service today on most 500kV and 750kV transformers in that area. This technology was only utilized in the former Soviet Union until the eastern block and the Soviet Union began to open up their borders which eventually led to the Soviet Union being dissolved into a confederation of several independent states in 1991. With the opening of the borders, several new technologies were introduced to the rest of the world.

On-Line Testing in the U.S.:

In 1988, United States Patent 4,757,263 was issued to Harold Cummings, Frank Diviney, and the Tennessee Valley Authority for an on-line Insulation Power Factor Alarm Monitor [4]. The device measured the current from the test tap on a bushing or instrument transformer and compared the signal to a reference voltage from a voltage transformer or potential device to calculate the power factor of the insulation system and provided alarms if the values reached the alarm setting values. This measurement method is now referred to as the Reference method.

Thermovision was originally developed in the 50's for military uses but the costs of the cameras were very high so the uses were limited. By the 90's, the costs had fallen to affordable levels and regular infrared inspections began to be performed in energized substations. For bushing monitoring, the technology is mostly limited to detecting hot terminal connections but can also detect hot areas of the bushing top section that have suffered from gasket deterioration, water intrusion and corrosion between current-carrying parts.

There was a great deal of development with on-line bushing monitoring systems in the U.S. in the late 1990's by a small number of utilities and developers.

Viktor Sokolov, the Technical Director of the Center of Science – Engineering Service in the Ukraine was active in the 1990's and 2000's in promoting on-line bushing monitoring and other innovative technologies. He authored or co-authored numerous papers for CIGRE, IEEE, Doble, TjH2b and other groups covering transformer reliability, testing, maintenance and monitoring.

Zalya Berler, a former engineer with Northern States Power, formed the Integrated Partial Discharge Diagnostics company in partnership with Westinghouse in the early 1990's and installed one of the first on-line bushing monitoring systems in the US at a Marathon Oil facility in 1995. He also authored or co-authored several papers on transformer and bushing monitoring. These early systems utilized bushing sensors that were connected to test terminals at a small cabinet that could be accessed from ground level. A portable test set was used to test the bushings and could be configured to test the bushings for partial discharge as well as using three different possible methods which are still used today, the Sum-of-three-currents, Reference, and Comparison methods.

Around 1995, 1996 and 1997, Jeff Benach with Megger, Barry Ward with Avo, and Stan Lindgren with EPRI worked together with Predrag Vujovic and Kevin Fricker with the Council for Scientific and Industrial Research (CSIR) in South Africa to develop a continuous on-line monitoring system with algorithms for the determination of tan δ power factor and capacitance on high-voltage CT's or bushings from the test tap voltage. Tests were performed [5] at the Bonneville Power Authority's High Voltage Lab as part of an EPRI project to test 7 EHV CT's at progressively higher applied voltages to the point of failure and monitor the CT's with three basic types of monitors, an on-line bushing monitoring system for tan δ and capacitance, an acoustic Partial Discharge (PD) monitoring system, and an on-line DGA monitor for dissolved combustible gasses. Five of the seven CT's failed. The tests found that changes in the tan δ and capacitance values were the best early predictors of a failure, but Leakage current and PD. This voltage method for determining tan δ and capacitance is also used today.

Original Monitoring Methods:

The sum-of-three-currents method adds the three individual phase bushing leakage currents to obtain a residual current, similar to a neutral current in a wye-connected three-phase system. An increase in the magnitude of the residual current is an indication in deterioration in one or more of the bushings.

The reference method compares the bushing leakage current for each bushing to the corresponding bus voltages from potential transformers (PT's) or Capacitive Coupled Voltage Transformers (CCVT's). The magnitudes and phase angles of the leakage currents and reference voltages are used to determine real C1 power factor and capacitance.

The comparison method compares the bushing leakage current to the leakage current from the same voltage and phase bushing on a second transformer to determine real bushing C1 power factor and capacitance values.

The voltage bridge method uses a virtual Schering bridge circuit to compare the voltages of the tested bushing and adjacent phase bushings to determine bushing C1 tan δ power factor and capacitance.

Early Utility On-Line Bushing Monitoring Installations:

In 1997, I was working with Florida Power and Light (FPL) as a large transformer Subject Matter Expert and Asset Manager when we evaluated some of these early systems using the sum-of-three-currents, reference and comparison methods. While these systems were more a type of terminal cabinet than monitoring system, we saw a great potential benefit with these systems since we did not need to schedule outages for periodic off-line testing, but we needed to evaluate the systems for accuracy and reliability. Our experience with off-line testing led us to have concerns about the effects of surface contamination and other environmental influences on the on-line data, but we monitored data from 5 different sites on a weekly to monthly basis and our tests showed this to not be an issue with effectively consistent data each time. Test results from one of these early evaluations comparing off-line and on-line data are shown below in Figure 3. The data show power factor values consistent to within 0.01% and capacitance values consistent to within +/- 2 picoFarads.

	NAMEPLATE C1		OFF-LINE		ON-LINE			
	CAPACITANCE (PICOFARADS)	% POWER FACTOR	CAPACITANCE (PICOFARADS)	% POWER FACTOR MEASURED	CAPACITANCE (PICOFARADS)	% POWER FACTOR MEASURED	CORRECTION FACTOR (DEGREES)	CORRECTED POWER FACTOR
H1	606	0.13	580	0.26	581	0.30	0.02	0.26
H2	604	0.13	570	0.26	570	0.59	0.19	0.26
H3	640	0.35	600	0.33	599	0.38	0.03	0.33
X1	359	0.28	344	0.26	342	0.35	0.05	0.26
X2	350	0.20	336	0.23	337	0.47	0.13	0.23
X3	363	0.29	350	0.26	350	0.67	0.23	0.26

Figure 3 – Comparison of Off-Line and On-Line Bushing Test Results (Comparison Method)

Similar evaluations on the same systems were also being performed by Danny Bates with Alabama Power, an operating group of the Southern Company, around the same time. We were able to compare results and best practices. We both concluded that the systems met our needs and could provide the benefits that we were both looking for.

Also during this time, Zalya Berler established ZTZ Services, International in Miami, Florida, to design and manufacture on-line monitoring systems working with Vladimir Prykhodko, and FPL and Alabama Power migrated to the ZTZ Service monitoring systems. We used both the ZTZ Services Vector test set and the Doble M4000 test set at FPL for data measurements.

Additional Monitoring Methods:

In the late 1990's and early 2000's, Doble Engineering worked with Viktor Sokolov to study the data from sum-of-three-currents monitors in Russia and start development of an on-line bushing monitoring system.

Mark Lachman, David Train, and Phillip von Guggenberg worked with Doble Engineering around that same time to develop the algorithms to extract the individual phasors from measured data and to develop their first on-line bushing monitoring systems using the sum-of-three-currents method.

Doble continued work to develop algorithms to compare the magnitudes and phase angles of the leakage currents from 3 bushings in a set to each other to calculate relative C1 capacitance and power factor values. This method is known as the Adjacent Phase method and variations of this method are used by a large number of on-line bushing monitoring systems available today.

While the Adjacent Phase method could provide calculated power factor and capacitance values, the calculated power factor values were found to be sensitive to fluctuations in the power system phase angles at many sites, resulting in cyclical data that could vary substantially in some cases. While users had relative power factor and capacitance values, they found that these relative values were not consistent with off-line test values and could not be used with the off-line pass/fail criteria that they used for evaluating the bushing's condition and substantially higher alarm values were required. In order to address these issues, monitoring system suppliers responded with smoothing and filtering algorithms to reduce the cyclical variation.

Also, some systems incorporated PD monitoring into the bushing monitoring system which provided partial discharge data in addition to imbalance current, power factor and capacitance data.

Refinement of Original Methods:

Another solution to the variability of relative power factor and capacitance was a return in 2014 to the Reference and Comparison methods that were used on early test terminal type systems, but now applied to continuous on-line monitoring systems. With test terminal systems, the data must be consistent since each sample is only taken on a periodic basis, like with traditional off-line tests. The reference or comparison methods do not have the inherent sensitivity to fluctuations in the power system voltages and phase angles and when applied to on-line systems can provide smooth and consistent data without any smoothing. Figure 4 shows data from the same bus at a west Texas windfarm for an Adjacent Phase method system installed in 2007 and a Reference method system installed in 2014. The graph on the left shows the unsmoothed data obtained with the Adjacent Phase method to produce relative power factor values and the graph on the right shows another set of bushings connected to the same bus, but using the Reference method to obtain real power factor values displayed on the same scale. With these types of methods, real data that is not significantly affected by outside influences can enable continuous on-line data monitoring systems to provide test results that is effectively equivalent to traditional off-line test data. This allows traditional pass/fail criteria to be used rather than evaluating general trends and rates of change.

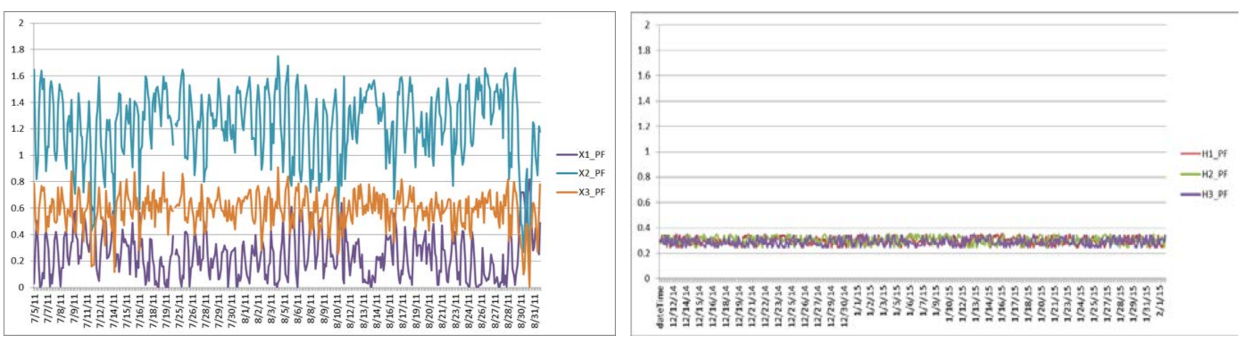

Figure 4 – Comparison of Adjacent Phase and Reference Methods

The Future of Bushing Monitoring:

As power systems grow and are increasingly controlled remotely by utilities or central operating authorities, the need for on-line monitoring will grow significantly. Within the next 20 years, it seems likely that all critical powerplant and substation equipment will be monitored as effectively as possible.

Refinements and improvements will continue, and the existing on-line monitoring methods will continue to be utilized:

- C1 power factor and capacitance
- Thermovision scans for hot spots
- Periodic local or remote visual inspections
- PD monitoring will be more widely used

Other systems may be developed such as:

- Bushing oil DGA monitors
- Systems for testing neutral bushings and C2 power factor and capacitance on regular bushings
- Local thermal monitors
- Smart analysis algorithms and systems
- Integrated systems utilizing bushing monitoring signals for transformer monitoring such as transformer power factor and impedance, Geomagnetic Induced Current events, on-line impedance measurements and on-line frequency response measurements

Bushing monitoring technology has matured significantly and continues to improve from the early days of Tesla and nothing but visual inspections and today a large number of suppliers can provide users with several reliable options for the data they want to evaluate.

References:

[1] US Patent 1,945,263, “Apparatus for Testing Insulating Values”, January 30, 1934

[2] Sokolov, V. V., Vanin B. V, "On-Line Monitoring of High-Voltage Bushings," Proceedings of the Sixty-Second Annual International Conference of Doble Clients, 1995, page 3-4.1.

[3] Svi, P. M., “Diagnostics of Insulation of High Voltage Equipment”, Energo AtomIzdat, 1988

[4] US Patent 4,767,263, “Insulation Power Factor Alarm Monitor”,

[5] Bradley, D.A., “Detection of Imminent Failure of Oil-Filled Current Transformers” EPRI

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48th Annual

Transmission and Substation Design and Operation Symposium

Field Transformer Demagnetization

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Abstract

Once installed, power transformers are expected to provide continuous, reliable and safe operation throughout their service life. In order to meet the expectations of manufacturers and operators, a well-defined set of quality control and testing procedures are carried out in the factory and in the field.

With that premise, manufacturers and field operators are concerned about the non-linear effects of the magnetic flux and the residual magnetism in the electro-magnetic system of power and distribution transformers, resulting in magnetizing currents and inrush currents.

Various explanations have been provided for transformer core saturation and its effect on the performance of the transformer itself. In this paper, authors are mainly concerned with switching operations and direct current applied during routine testing procedures of static winding resistance measurement that may leave residual magnetization in the core and/or fully saturate the core of the transformer.

When a magnetized power transformer is energized, it will face extremely high magnetizing currents due to the non-linear phenomenon of core saturation. The high level of inrush currents generated upon energization may affect the internal winding geometry of the transformer and also trip harmonic protection devices in the system.

This paper will discuss the demagnetization of the magnetic core of power and distribution transformers. Different algorithms are applied to a variety of transformer designs and the results are validated with excitation current measurements and Sweep Frequency Response Analysis (SFRA) tests. The knowledge acquired and the best practices suggested for transformer demagnetization are summarized for practical application in the field.

I. INTRODUCTION

Residual magnetization in the core is a current topic of long-time concern for many transformer manufacturers and field operators. The problem has been addressed in international standards and major technical references [1] - [6]. Core magnetization to the level of saturation may result from operational problems and demagnetization is recommended before a transformer is energized and before AC testing procedures such as exciting current and SFRA are carried out.

During DC static winding resistance measurements, core saturation is desired because it cancels the inductive effect and allows only the voltage drop through the resistive component of the winding to be measured. The transformer core may otherwise become saturated due to an abrupt change in the voltage applied to it. This may be caused by switching transients, out-of-phase synchronization of a generator, external faults and fault clearance.

In transmission and distribution networks, energization of transformers is a common practice and it is generally performed without any adverse consequences [6]. Nevertheless, switching operations generate currents and voltages that are transient in nature and may create power quality issues during the energization of the transformer.

A way to satisfactorily demagnetize the core of the transformer before energization is needed, and the process must be well understood, with practical examples provided to ensure correct application in the field. Like any generic algorithm, a demagnetization procedure may work fine for one transformer and not that well for other transformer construction. Therefore, the limitations of demagnetization algorithms should be described for ease of application in the field.

II. THE CORRELATION BETWEEN CORE SATURATION AND HIGH INRUSH CURRENTS

Although inrush currents are not generally as damaging as fault currents, the duration of exciting current inrush is in the order of seconds or even minutes. Inrush Current is a form of over-current that occurs during energization of a transformer and is a large transient current which is caused by part cycle saturation of the magnetic core of the transformer [7]. The flux in the core is equal to the integral of the excitation voltage. Assuming the condition of energization when the voltage passes through zero and the flux is zero, the sinusoidal flux will be fully offset from zero. The energization of a transformer normally yields the most severe case of inrush current as the flux in the core can reach a maximum theoretical value of 2 to 3 times the rated peak flux but slowly decreases by the effect of oscillation damping until it finally reaches the normal exciting current value[6][10].

The flux-linkage/current relation is nonlinear and is determined by the saturation curve of the transformer. Therefore, the magnetization current of a transformer contains harmonics. When a transformer is energized, the initial value of the flux may differ from the prospective flux. This causes a DC offset of the flux-linkage and a higher-than-rated peak value. The result is an inrush current that may be several times the value of the nominal current.

An ideal transformer is based on two principles; a variable electric current produces a variable magnetic field; and this variable magnetic field produces a voltage across the ends of the coil. For better coupling of the two effects, a ferromagnetic material is used as presented in Figure 1.

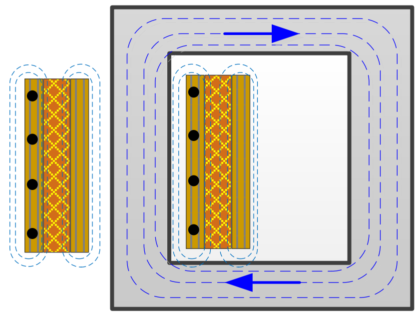

Figure 1. Transformer electro-magnetic principle

For the ideal transformer working under normal operation conditions, the *v-i* curve is depicted in Figure 2.

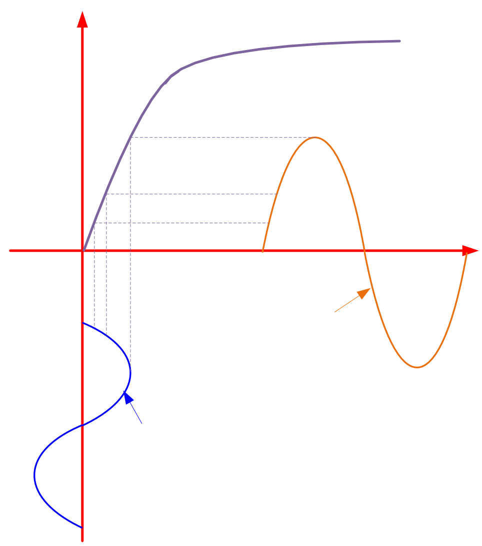

Figure 2. v-i curve of a transformer under normal conditions

Under real conditions , where the transformer core materials experience a flux that periodically changes, the B-H curve depends on the magnitude of the flux density and the periodic frequency.

The main factors affecting the inrush current magnitudes can be divided into: transformer design, initial conditions, and network factors.

The design of a transformer can affect the magnitude of the inrush current as it can shift the steady state operating point on the saturation curve. A transformer with an operation point closer to the knee area of the saturation curve is easily brought into saturation.

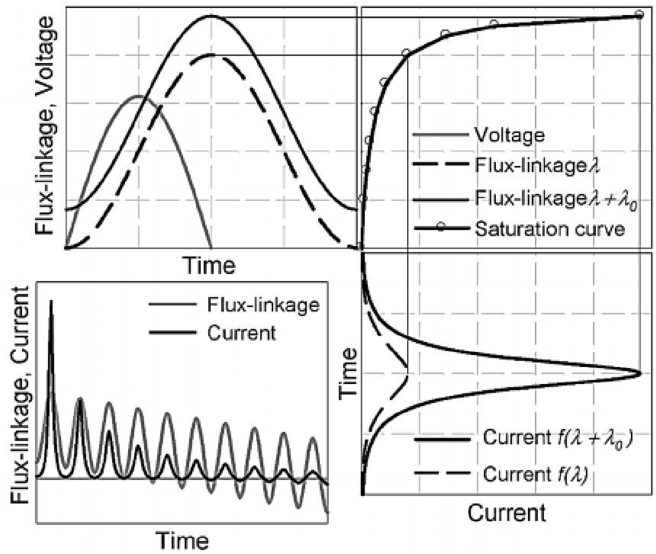

Figure 3. The inrush current and the effect of residual flux [6]

The generic and simplified equation that has been used in the industry to calculate the peak value of the first cycle of inrush current in Amps is as follows:

$$I_{pk} = \frac{\sqrt{2} \cdot U}{\sqrt{(\omega \cdot L)^2 + R^2}} \cdot \left(\frac{2 \cdot B_N + B_R - B_S}{B_N} \right) \tag{1}$$

Where:

U – Applied voltage [V]

L – air-core inductance of the transformer [Henry]

R – DC resistance of the transformer winding [Ohms]

B_R – Remnant flux density of the core [Tesla]

B_S – Saturation flux density of the core material [Tesla]

B_N – Normal rated flux density of the core [Tesla]

An improved, more rigorous, calculation for inrush current has been developed by ABB in 2007 [7] which takes into consideration additional design parameters of the transformer:

→ The magnetizing inductance of the transformer core adjusted for the transient nature of the inrush current phenomenon.

→ Impedance and short circuit capacity of the system.

→ Core geometry, winding configurations, and winding connections in 3 phase transformers.

As clearly observed, transformer saturation is a highly nonlinear phenomenon and hence the inrush current contains harmonic and DC components besides the fundamental component. The 2nd harmonic is by far the most dominant one.

To minimize and control transformer inrush currents, and prevent undesirable effects on the electric system, the following methods have been proposed:

→ Controlling the switching times of the energizing circuit breaker

→ Installing pre-insertion resistors in series to the energizing circuit breaker

→ Adjusting the load tap changer before energizing the transformer

→ Reducing the system voltage before energizing the transformer

→ Energizing the transformer using air-break disconnect switches

→ De-fluxing / de-magnetizing the transformer core before energization

III. THE TESTING IMPLICATION

In this section we review the international standards covering the best field testing practices for power and distribution transformers.

A. IEEE C57.152 – 2013 section 7.2.7.4 Demagnetization after winding resistance measurement

The direct current used to measure winding resistance may cause the core to magnetize (polarize). A magnetized core can cause high inrush currents when the transformer is energized. To help reduce damage to the transformer and associated protection systems, the core may be demagnetized prior to applying full alternating current (AC) voltage.

The demagnetizing procedure consists of applying direct current to the windings and reversing polarity a number of times while reducing the current applied until the core is demagnetized.[1]

An alternate method is to apply a significant portion of the ac voltage and then gradually reduce the voltage; however this factory method is seldom available in the field.

B. IEEE C57.152 – 2013 section 7.2.11.1.1 Effect of Residual magnetism on excitation current measurement

The transformer core may have residual magnetism present as a result of being disconnected from the power line or, as is frequently the case, as a result of dc measurements of winding resistance. The residual magnetism results in the measurement of higher-than-normal excitation current.

In most of the problems detected by excitation current measurements, the currents of the outer phases of three-legged, three-phase transformers have exceeded 10%. Smaller changes in the currents of symmetrical phases may also be indicative of problems associated with the core and should be investigated. If a significant change in the test results is observed, the only known reliable method of excluding the effect of residual magnetism is to demagnetize the transformer core. [1]

It is recommended that the DC measurements of the winding resistance be performed after the excitation current tests.

C. IEEE C57.152 – 2013 section 7.2.11.1.2 Methods for demagnetization

Two techniques can be used to demagnetize the transformer core:

a. The first method is to apply a diminishing alternating current to one of the windings. For most transformers, due to the high voltage ratings involved, this method is impractical and involves safety hazards.
b. A more convenient method is to use direct current. The principle of this method is to neutralize the magnetic alignment of the core iron by applying a direct voltage of alternate polarities to the transformer winding for decreasing intervals. The process is continued until the current level is zero. On three-phase transformers, the usual practice is to perform the procedure on the phase with the highest excitation current reading. In most cases, experience has demonstrated that this procedure is sufficient to demagnetize the whole core.

D. IEEE C57.149 – 2012 and CIGRE 342

Sweep Frequency Response Analysis (SFRA) is fundamentally a comparative test. The influence of residual magnetism may have an influence on the trace comparison. When a benchmark is created, residual magnetism can cause the lower frequencies (up to about 5 kHz) of the trace to be slightly offset. Therefore, the person in charge of analyzing SFRA results understands that residual magnetism in the core of the transformer is not a failure condition, but is an indication of the flux density that remains in the core steel.

DC winding resistance testing, switching operations and geomagnetic phenomena are sources of residual magnetism. Residual magnetism in SFRA traces can be identified by the shifting of the low frequency core resonance to the right as compared to the demagnetized results. Residual magnetization can be removed by demagnetizing the core, and should be conducted if there is concern about the condition of the core [3].

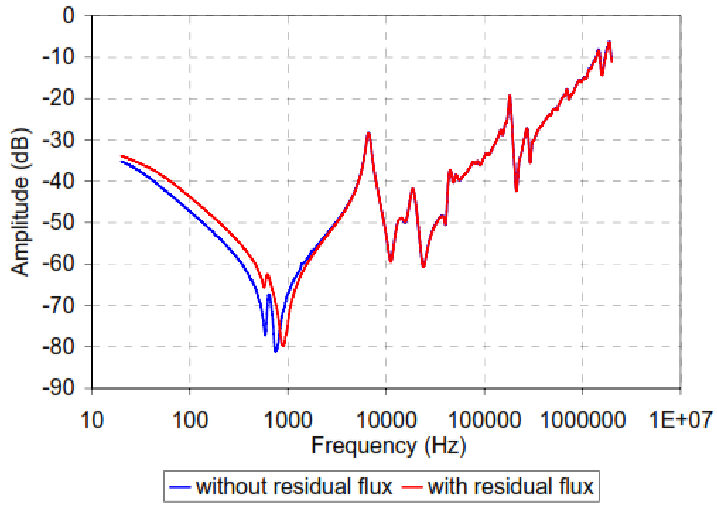

Figure 4. Effect of magnetized core on FRA results [4]

IV. Experimental Work

The demagnetization of transformer cores can be performed in several ways as discussed in [9]:

→ Variable Voltage Constant Frequency (VVCF) source;

→ Constant Voltage Variable Frequency (CVVF) source;

→ Decreasing the amplitude of an alternating DC current.

In this section a variety of algorithms are tested and validated. Saturation of the core is reached by overvoltage applied to the secondary winding and by DC current injection. Validation of the efficiency of the procedure is measured by the SFRA method and excitation current measurement on the HV side of the transformer.

A. The generic algorithm

The generic algorithm to demagnetize the core is as follows:

- Select the input parameters:
  - Start current (e.g. 10 A)

- Interval (e.g. 80%)
- Procedure:
  - Start by injecting +10A.
  - Discharge and then charge transformer to -10A.
  - Scale your Vs and set:
    - 0 Vs as origo
    - Scale your FLUX axis
    - Set new starting point @ 80% of previous pass
- Repeat many cycles
- Ready

B. Case study – W-1970

For illustration of the different processes to be discussed, a 1MVA 3-ph, 13.8/0.48 kV Westinghouse transformer manufactured in 1970 with a Dd0 configuration is used.

The SFRA response in open circuit mode when the unit is fully demagnetized is presented in Figures 5 and 6 below

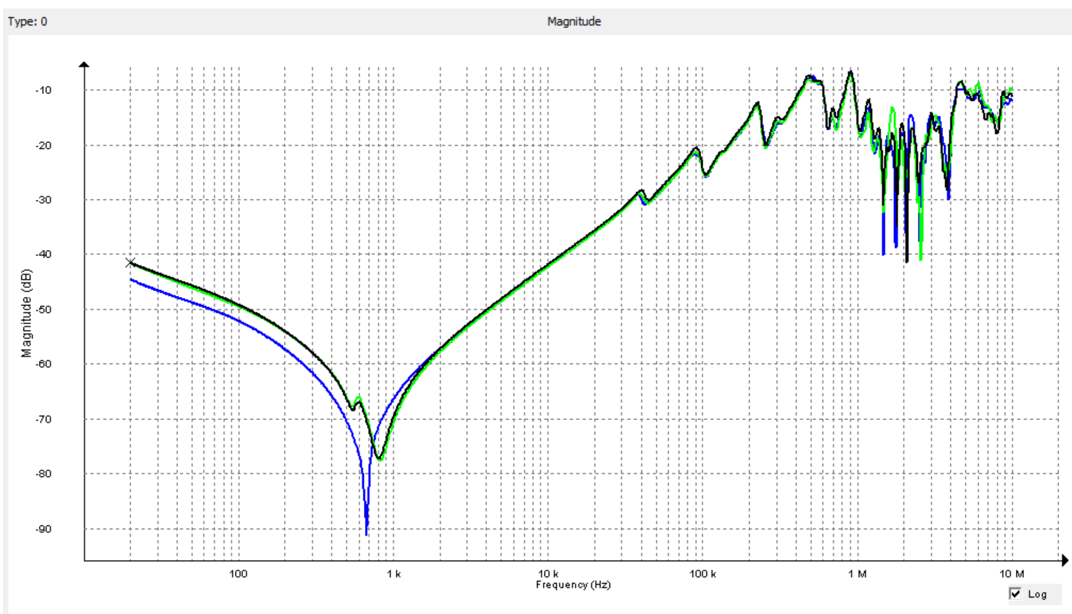

Figure 5 Open circuit response for fully demagnetized HV windings of Westinghouse 1970

The SFRA response of the HV winding in open circuit mode when the unit is fully demagnetized is presented in Figure 5

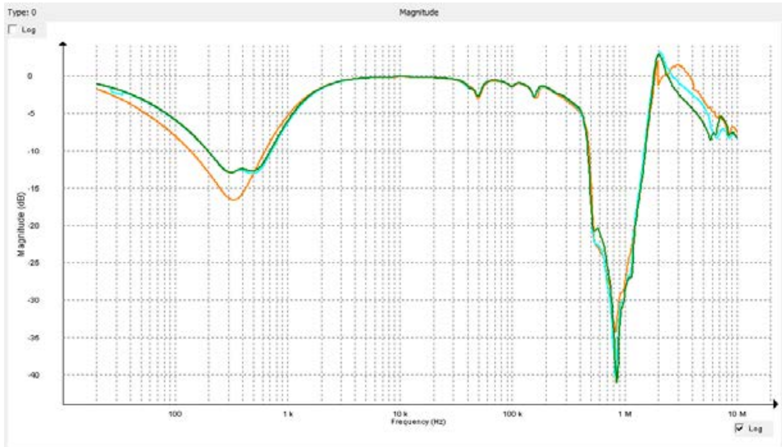

Figure 6 Open circuit response for fully demagnetized LV windings of Westinghouse 1970

Saturation of the core is obtained by static winding resistance measurement on all three phases.

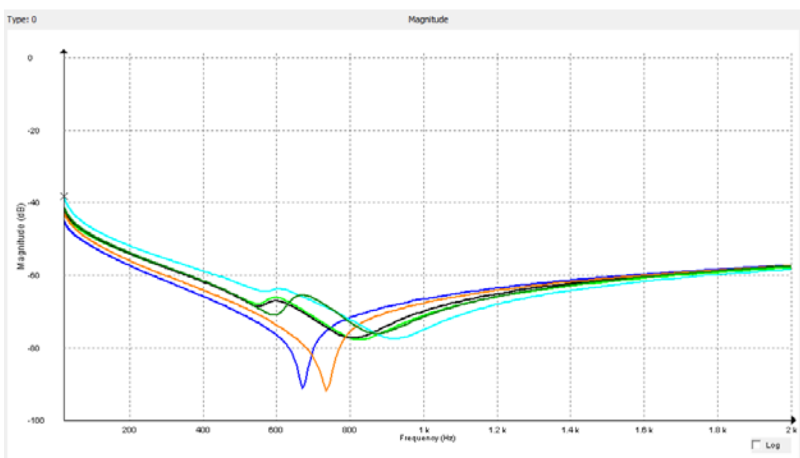

Figure 7 Open circuit response for magnetized windings of Westinghouse 1970

The effect of saturation is clear and without in-depth analysis we can see that the symmetry of the phases has been altered. It is time now to approach demagnetization using the DC algorithm described above. First the algorithm is applied to only one phase (B) and results are observed in SFRA response.

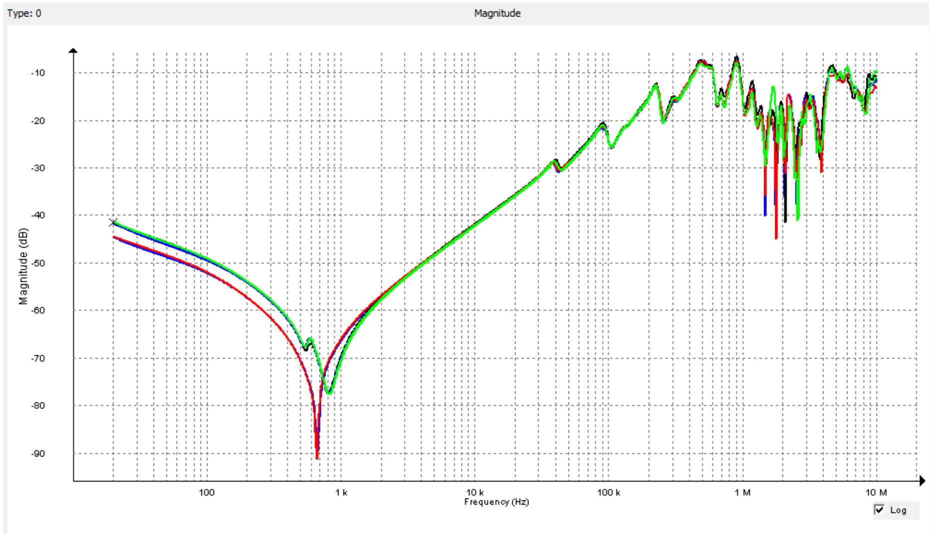

Figure 8 Original signature of HV windings and after demagnetization of B phase

Looking at the full scale, it is almost impossible to visualize any difference with respect to the benchmark signature. A closer look is needed in the linear scale.

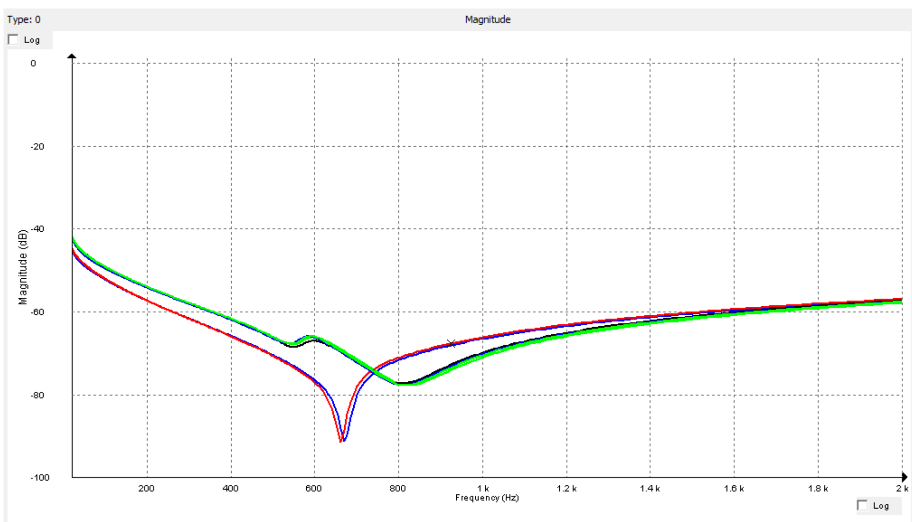

Figure 9 Frequency band from 20Hz to 2kHz - Original vs. demagnetization on B phase

As observed, the algorithm has effectively responded and is now clear a minor discrepancy visible only in the linear scale for the first point of resonance.

Next, the demagnetization algorithm is applied to each and every phase following the flux sequence.

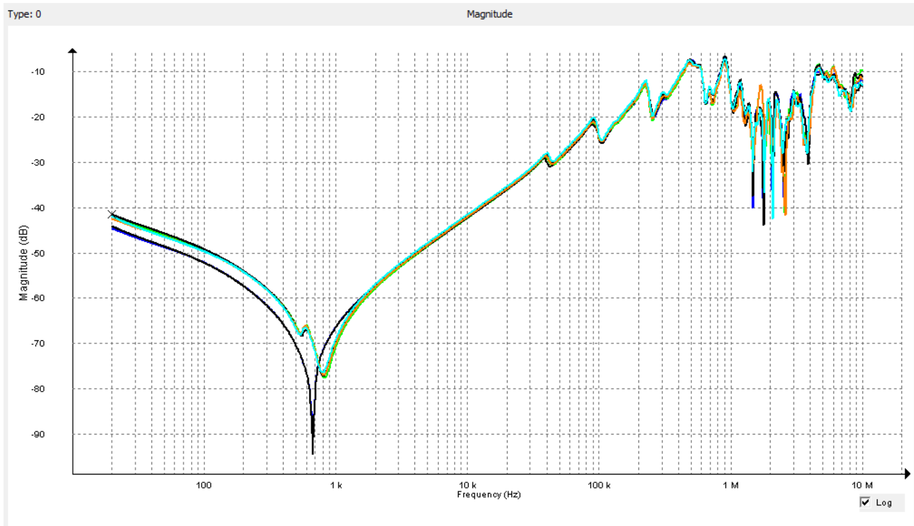

Figure 10 Original response vs. demagnetization of all 3 phases

Once again, there is a good correlation between the original signature and the after demagnetization signature. Let's look at it closer:

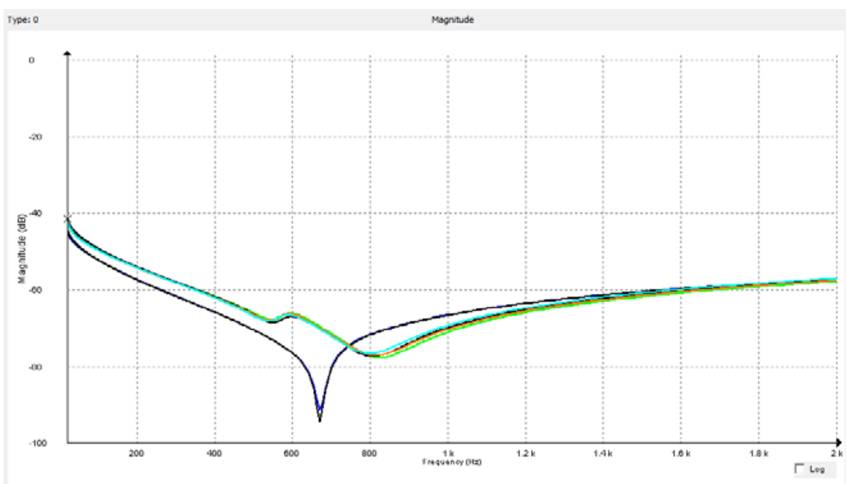

Figure 11 Frequency band from 20Hz to 2kHz - Original vs. demagnetization on all 3 phases

For a better understanding, it is considered in this work to show graphically the differences between both demagnetization methods.

- Central leg of the transformer – Initial condition vs. fully saturated core after winding resistance measurement

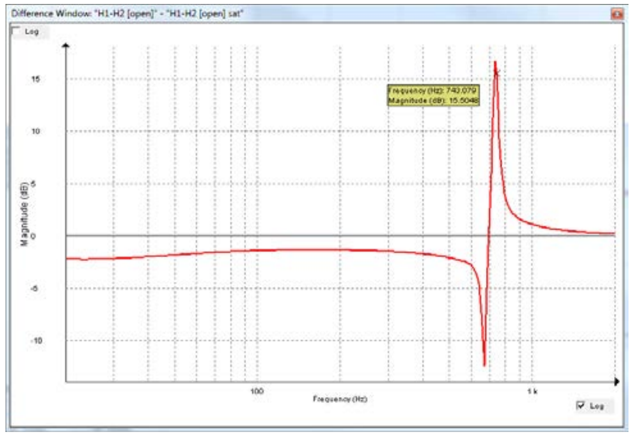

Figure 12 Difference in magnitude - asymmetrical phase only, original vs. fully magnetized core

- Central leg of the transformer – Initial condition vs. demagnetization on B phase

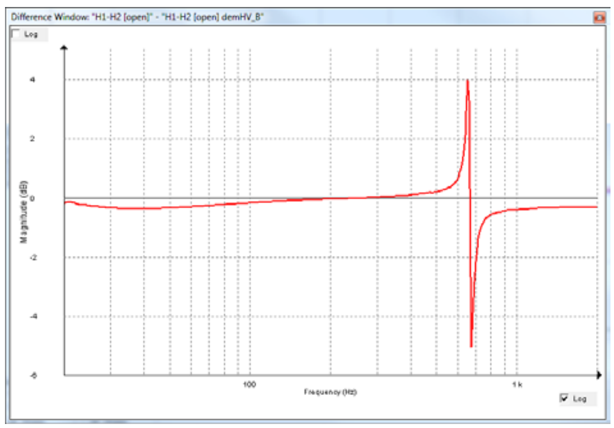

Figure 13 Difference in magnitude - asymmetrical phase only, original vs. demagnetization on B-phase

- Central leg of the transformer – Initial condition vs. demagnetization on all phases

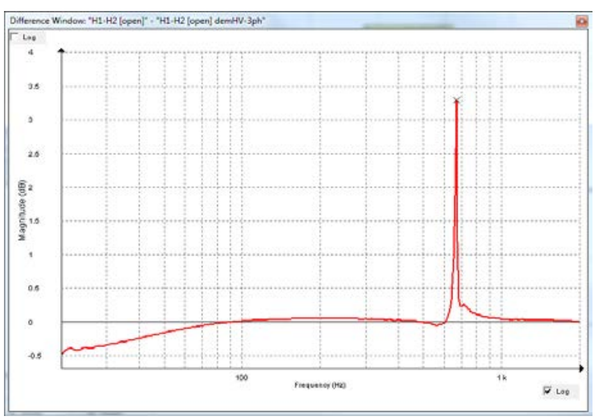

Figure 14 Difference in magnitude - asymmetrical phase only, original vs. demagnetization B-phase

IV. CONCLUSIONS

- Demagnetization of power transformers in the field is practical using the DC method of alternating pulses. Approaches to demagnetize the transformer might be different, only one phase or all phases.
- The effect of each individual approach might be different depending on the type, size and construction of the transformer. Minor discrepancies may be encountered as presented in Figures 13 and 14 that may not be observed at first glance in the SFRA response, unless a more detailed analysis is performed in the linear scale and in the frequency range from 20 Hz up to 2 kHz. The deviations observed must be understood by SFRA users not to confuse with potential problems in the core of the transformer.
- The algorithm in deed cancels the residual magnetism in the core and minimizes the stress during re-energization of the transformer, not increasing the magnitude of inrush currents. Further work is carried out validating algorithms with other methods such as magnetic balance.

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Galvanized Steel Pole and Lattice Tower Corrosion Assessment and Corrosion Mitigation

To be presented at:

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SUMMARY

The principal corrosion mechanisms for galvanized steel electric power utility transmission and distribution (T&D) structures (poles, lattice towers and anchor rods) are presented in this paper. Several important factors often associated with corrosion of galvanized utility structures are deficiencies in corrosion control, coating, soil corrosivity conditions, stray current corrosion, lack of cathodic protection, and copper grounding at the site or at substations. These factors are of primary consideration when accelerated corrosion attack occurs. If identified early on, potential failures can often be prevented. This paper also addresses: (1) Soil Corrosion and Forecasting Soil Corrosivity, (2) Inspection Techniques with Associated Confidence Level Ratings, and (3), Corrosion Mitigation and Cathodic Protection (CP). As part of this paper, a case history of a utility that implemented an innovative system wide CP program after discovering corrosion on embedded poles. To determine the root cause of corrosion a failure, a failure analysis was performed. This paper combines four past publications as well as presents new information and strategies for corrosion prevention for electric power utility T&D structures.

INTRODUCTION

Galvanized steel is one of the most often specified materials for the manufacturing of poles, lattice towers and other transmission and distribution (T&D) assets commonly used in the electric power utility industry. The galvanized poles and towers are often embedded with the depth dependent on soil strength and applied overturning moment. Galvanizing is to meet the ASTM A123 requirements for pole and A153 for hardware. Methods to mitigate corrosion, beginning from the manufacturing process and through the various life cycle phases are addressed in the following sections.

Metallurgical Aspects of Galvanized Steel Poles and Towers

Electric power T&D pole and lattice tower steel material typically conforms to the mechanical and chemical properties listed in American Society for Testing and Methods 2 (ASTM) specification A572-04. The minimum yield strength of this material is 65,000 PSI. The maximum silicon content of all steels is 0.06 % to ensure an adequate free zinc and uniform galvanized finish. The mechanical strength requirements for structural performance, such as tensile strength, (assuming the inherent material strength remains constant), is then dependent on the material cross-sectional area. If inadequate, tensile failures could occur at locations where corrosion has produced localized reductions in cross-sectional areas and created stress raisers. Higher tensile strength steels have less ductility and toughness, and these steels are considered notch sensitive. Normal constructional steels would not typically be notch sensitive but high strength low alloy (HSLA) steels can be notch sensitive. Corrosion pitting can create the notch which then may become the location of crack initiation. Pitting or reduced areas that are due to corrosion can also initiate mechanical fatigue cracks. As a quality control check to ensure a selected steel material has adequate notch sensitivity and toughness several tests are usually employed with the most common a ‘Charpy V-notch (CVN) Impact Test.

In general, steels from the mill should be guaranteed to have a minimum energy impact value of 15 ft-lb for utilize specimens at -20°F to -40 (depending on minimum temperatures at structure sites) as measured by a CVN testing accordance with ASTM A370 and A673. These standards specify that plate test specimens are to be taken after rolling and finishing operations. This procedure is used to detect slow strain rate embrittlement failure mechanisms, such a hydrogen embrittlement (HE) and grain boundary segregation (GBS). It should be noted that liquid metal embrittlement LME (loss of ductility) due to galvanizing is very rare and should be confirmed by metallurgical failure analysis.

Variations in heat treatment and associated cooling rates can affect the corrosion potential and even result in galvanic couples between different areas of the same steel component. Such examples would be welds and their heat affected zones and the adjacent unaffected steel. Magnetite, if present, can provide initial corrosion protection but at locations where the scaling produced from the welding process has cracked localized galvanic cells and accelerated corrosion can occur. Decarburized surface layers are also prone to accelerated corrosion but are not always present.

While the galvanized coating usually consists of several intermediate intermetallic (Fe-Zn) layers with the top surface layer being composed essentially of free zinc, as shown in Figure 1. This layer defines the appearance of galvanized structure. Typically freshly prepared hot-dip galvanized steel has a smooth, shiny surface with the well-known zinc spangle pattern, provided the steel substrate chemistry and galvanizing bath were adequately controlled. This ductile zinc surface layer commonly comprises at least 30 to 40% and sometimes as much as 70-80% of the total galvanized coating thickness. However, certain elements in the steel base or in the weld metal can promote the formation of a coating that is entirely composed of Fe-Zn intermetallic layers with limited or no free zinc barrier layers. When this occurs, the galvanized steel may look matte gray in color and have a rough surface. Through the addition of alloying elements and control of the galvanizing bath, large galvanizing operations have been able to produce utility poles and lattice towers that can last a long time and at the same time avoid intermetallic rust for decades.

The microstructure of hot-dip galvanized steel depends on the composition of steel and the galvanizing bath composition. In general, silicon composition less than 0.04% or between 0.15 and 0.25% is recommended. Si and P act synergistically, increasing the rate of the iron/zinc intermetallic reaction, which leads to thick coatings. Phosphorus less than 0.04% or manganese less than 1.35% are beneficial. Excessive silicon accelerates the reaction between Fe and Zn, resulting in a coating that can consist completely of Fe-Zn intermetallic layers. Higher Si concentrations can also lead to coatings that are much thicker overall than coating specifications require.

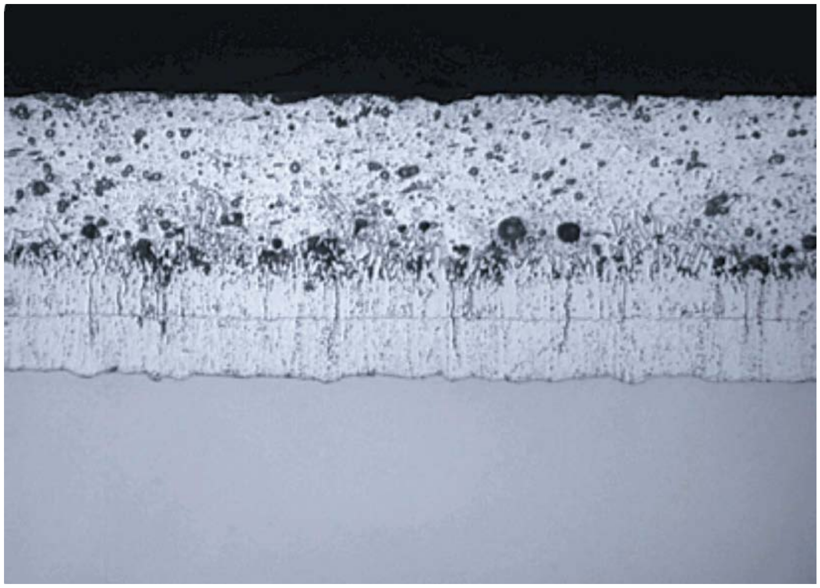


Figure 1: Galvanized steel intermetallic layers: Eta (100% Zn), Zeta (94% Zn), Delta (90% Zn), and Gamma (75% Zn).

According to an American Galvanizers Association document, such coatings may “have a lower adherence when compared to the ‘typical’ galvanized coating. This type of coating tends to be thicker than the ‘typical’ galvanized coating. As the thickness of the coating increases, a reduction of adherence may be experienced.

Thick galvanizing on the order of 7 mils (178 μm) or more depending on free zinc layer thickness are especially brittle and will crack and peel off under mechanical stress or crack if severely impacted or subjected to cyclic loads. This may lower the fatigue resistance of pole components in general; however, experience indicates that cracking of embedded poles and lattice towers are rare.

Corrosion Characteristics of Galvanized Steel

Zinc is a highly reactive metal that exhibits a low corrosion rate only if a continuous passive film forms on the surface. An important aspect of corrosion control with galvanized steel is that the surface needs to remain in a soil environment that does not reduce or damage the protective surface film. Galvanized steel T&D structures are exposed to a wide variety of different soil environments and grounding that can also accelerate corrosion activity depending on soil chemistry, soil resistivity, and the nature and surface area of the grounding materials. See Figure 2.

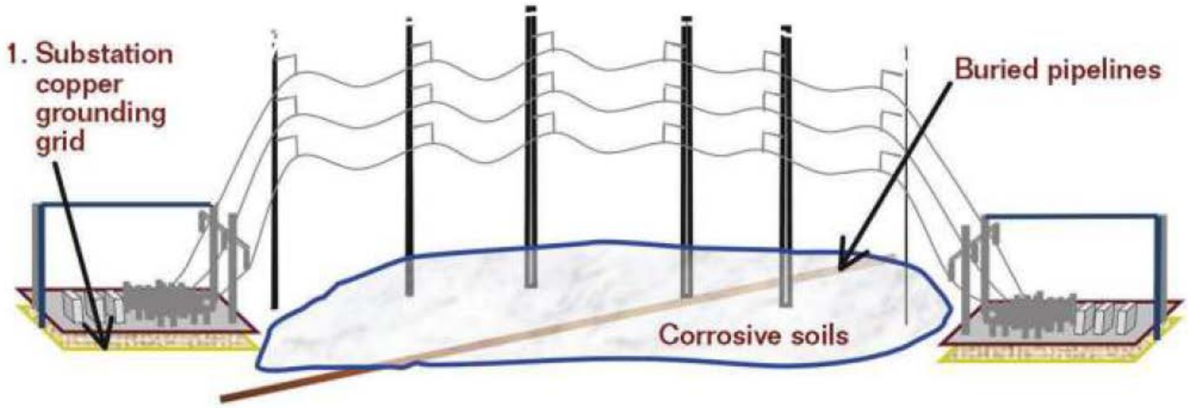


Figure 2: Transmission lines, corrosive soils, and substations form an integrated electrochemical system that accelerates corrosion.

Corrosion of Galvanized Steel Foundations

Under most soil environments, galvanized steel exhibits a low corrosion rate and performs well as it readily forms a protective file on the surface. Accelerated corrosion of the embedded portion of poles, lattice towers or othe galvanized steel structures can occur, however, if exposed to highly corrosive or reducing soil environments (i.e., acidic chlorides or microbiologically infulenced corrosion [MIC] is a necessary condition for accelerated corrosion to occur. Dry soil is not corrosive to galvanized steel. Water in soil may be present from water table, meteoric water and or capillary water. Salinity may vary from 80 to 1,500 ppm depending on location. Of special significance, it is important to realize accelerated corrosion can take place in absence of oxygen, due to presence of bacteria (MIC), acidic soil and stray currents. Outside electrical interference and stray currents can also accelerate corrosion of galvanized steel structures. CP and protective coatings can mitigate corrosion and extend the life of T&D structures in corrosive soils

In near neutral environments, corrosion is retarded by compact, adherent, insoluble corrosion products. Conversely, in highly acidic or alkaline environments, soluble corrosion products are formed, which destroy protective films and permit corrosion to proceed. If basic carbonate forms, the increase in pH does not take place preventing the formation of corrosion products or oxides.

The corroison resistance of galvanized coating increases because the formation of protective basic carbonate zinc extends the region of passivation toward neutral pH values. See Table 1.

Table 1: Cycle of Galvanized Steel Structure Corrosion

New Structure	Galvanized layer acts as a barrier and sacrificially protects the carbon steel substrate
Weathered Structure (zinc consumed) (corrosion rate dependent on soil corrosivity / atmosphere corrosivity and geometry, dry/wet cycles)	Corrosion products consist of zinc carbonate, zinc oxide, zinc hydroxide, zinc sulfate, zinc hydroxychloride, zinc chlorohydroxysulfate
Aged structure (galvanized consumed) (rate dependent on soil/atmosphere corrosivity, geometry, dry/wet cycles)	Corrosion products consist of hydrous ferrous oxide (red brown rust), hydrated magnetite and magnetite (black), ferrous hydroxide (blue/green)

Soil Corrosion and Forecasting Soil Corrosivity

Soils vary widely in their composition and behavior, even over short distances, which can make it difficult to obtain consistent data for designing a risk mitigation solution. While galvanized steel has considerable resistance to corrosion when buried, the greatest attack is caused by soils that are reducing, acidic, or contain large amounts of corrosive water-soluble salts. See Figures 3-6.

Figure 3: T&D structures may be exposed to all types of corrosion-induced environments, including MIC and stray current that require risk assessment.

Figure 4: T&D structures located in very corrosive and water-logged soils with active bacteria present.

Figure 5: Corrosive backfills lead to accelerate corrosion of T&D towers.

Figure 6: T&D towers in deep burial are subject to accelerated corrosion from corrosive ions.

In determining in the corrosiveness of a soil, the different constituent sol characteristics and relevant attributes of the physical environment should be considered. A ranking of the various factors is assigned in order of relevance to corrosion. The sum of those rating factors is a measure for the overall soil corrosiveness. Table 2 presents the key characteristics usually considered.

Table 2: Corrosion Parameters

Soil Characteristics
Factors / Attributes: Soil type, homogeneity, moisture content, pH, resistivity, chemical properties, buffer capacity, level of oxidation, organic content, presence of excessive sulfates, and chlorides could lead to microbiologically influenced corrosion (MIC).
Physical Environment Characteristics
Factors / Attributes: Time of wetness, ground water, and land use can indicate possible chemicals and salts, interference from electrical and impressed current CP (ICCP from gas lines), stray current, and galvanic action due to grounding and contamination.

It is important to have an understanding of the key factors that are measured or assessed to accurately and adequately interpret the results. For example, soil resistivity, which is an approximate measure of the concentration of reactant ions that lead to corrosion, typically decreases as the moisture and ionic as the moisture and ionic concentration increases. Generally, terrains with lower resistivity and reducing properties experience higher corrosion rates. All tests for the defined corrosion factors are typically performed using standard ASTM, CSA, NACE International, or AASHTO methods (or modified methods) developed from experience and testing.

The American Society for Testing and Materials (ASTM) has a different procedure as described in ASTM G57. The method described in ASTM G57, *Standard Test Method For Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method*, will be replaced by a two-part standard: Part A will cover the four-electrode method for in situ field measurements, and Part B will cover the use of a soil box for laboratory and field-test measurements.

Corrosion tests on galvanized steel poles / towers buried at different sites are performed by measuring soil resistivity measurements at different depths, pH, total dissolved solids (TDS), chlorides and sulfates, redox potentials (where applicable), resistance polarization measurements, and corrosion rate. It has been found that galvanized steel resists corrosion far better than bare steel at most sites. Table 3 shows the zinc corrosion rate in mils per year for sixty sites.

Table 3: Zinc Corrosion Rates for Corresponding Soil Types

Soil Type	Zinc Corrosion Rate (mpy)
Oxidizing clay	0.05 - 0.20
Reducing acidic soil	0.1 - 2.0
Salty Marsh	0.2 - 2.5
Moist natural clay	0.1 - 0.50

The corrosion rate for oxidizing soils decreases with the formation of protective layers on galvanized steel. In reducing soil, this layer does not form so the corrosion may increase over time. In this case, the structure should be adequately protected when located in reducing soils. For galvanized steel poles, protection should be applied both outside and inside the pole if the water table is high or is expected to be a concern. Agricultural soils are typically more corrosive because of the high concentration of corrosive ions in fertilizers. Likewise, structures exposed to excess amounts of road or ground water /seawater salts (sodium chloride (NaCL) experience higher corrosion rates from more exposure to chlorides. Based on past experience, accelerated corrosion will take place when chloride levels exceed 100ppm and sulfate levels exceed 1000ppm or when corrosive bacteria is present (SRB) in absence of oxygen.

Inspection Techniques and Confidence Level

The methods for determining corrosion risk of galvanized steel foundations include knowledge-based assessments that bring together materials science, metallurgy, electrochemical, and corrosion science with the understanding of how a structure is designed, built, and assembled. The key techniques involved are geared toward quantitatively determining the soil and physical characteristics in order to carry out a multi-factor risk based assessment of corrosion. The following tasks are recommended.

- Physical assessment of the soil service environment to rate corrosiveness
- Electrochemical testing of soil condition and steel interaction (potential values and soil resistivities to predict corrosion profile at lower depths)
- Focused visual, physical, and electrochemical assessment and testing of buried components at a shallow depth

In risk assessment, these test results should be taken into consideration along with structure age, size, design, function, and importance. Each structure is then assigned a below grade corrosion risk rating or condition assessment value. This rating is used to recommend appropriate remediation and mitigation procedures. Special attention should be given to tower designs that lead to accumulation of moisture and corrosive salts regardless of the foundation is buried in soil or encased in concrete. Depending on the method of evaluation, a level of confidence has been assigned to indicate the ability of that procedure to produce reliable corrosion risk data on their own without combining it with another form of assessment.

Desk Study (Least Confidence)

A desk study can be carried out using GIS data with geological records outlining soil parameter and survey results for assets. Data collected should include any available soils classifications, resistivities, corrosivity, pH and other relevant information if available. The accuracy and reliability of desk studies is based on the data used and the ability of the user to integrate all the relevant aspects in order to determine risk. This method does not account for shifts in terrain or the coarseness of map and geological data. See Table 4.

Table 4: Soil Corrosiveness Parameters

	Corrosiveness	
Soil Condition	**Corrosive**	**Progressively Non-Corrrosive**
Texture	Fine	Coarse
Color	Dark (black or grey)	Light (red or brown)
Acidity	High	Low
Aeration	Poorly aerated	Well aerated
Resistivity	Low	High
Organic content	Present	Absent
Moisture content	High	Low
Redox potential	Low or negative	High or positive
Sulfides	Sulfides present	low
Chlorides	Chlorides present or high	Low or absent

Soil Testing and Soil Sampling (Moderate Confidence)

Soil testing and sampling can be conducted by testing resistivity and electrochemical potential of the soil around footings and anchors. These parameters are the two key factors in the soil corrosiveness equations. The resistivity measurements will express the capacity of the soil to act as an electrolyte. The electrochemical potential measurements will express the soil's corrosion activity or how active it is towards an oxidative/reductive corrosion reaction. Corrosion rate measurements can provide maximum thickness loss and life expectancy estimates or remaining life under worst possible condition. This is a quantitative assessment that depends on the skill of the inspector, the condition and calibration of the instruments, and the sample size of the tests.

Knowledge-Based Inspection (High Confidence)

The target structure is inspected usually to a depth of 36 inches (914 mm) below grade. Soil samples are collected in areas of concern based on soil resistivities <2000 ohm-cm and where structure-to-soil potentials exhibit accelerated corrosion activity. If corrosion on the excavated structure component shows signs of significant material loss, a more detailed and coating and steel substrate should be performed. Inspection of the protective coating consists of adhesion measurement, thickness measurement, and defect characterization. Measurement of corrosion rate (loss in thickness/unit time) is performed based on electrochemical polarization techniques, which determine the loss in thickness under worst wet conditions. The loss in thickness can be related to load bearing capacity and uplift resistance of the structure with a relationship established between member size reduction and uplift resistance. This is a quantitative assessment that focuses on each structure and allows engineers to determine the amount of galvanized steel thickness reduction (based on corrosion rate) a grillage foundation can sustain. Concrete inspection and, if required, petrographic analysis are performed for damaged or degraded concrete base structures. Soils with high sulfate content may also react unfavorably with concrete footing and foundations. This detailed quantitative assessment focuses on each structure and depends on the skill and training of the inspector. Because all the relevant corrosion and structural parameters are assessed in in addition to visual inspection during the detailed assessment, the level of confidence in the results from such knowledge-based inspections is high.

Assigning Soil Corrosivity Value

The soil around each selected structure can be assigned a soil corrosivity rating based on a number of parameters including soil resistivity, pH, chlorides, sulfates, and electrochemical polarization parameters.

We have developed an algorithm to rate the soil corrosivity as it relates to buried galvanized steel. According to this method the corrosion risk factor for underground assets is modeled by considering both soil corrosion indices and corrosion rate determination by LPR combined with focused measurement of the underground asset. In this approach, the dimensional measurements, LPR corrosion rate, stray current, electrochemical potentials are considered in corrosion risk assessment and risk factor calculations for below grade assets.

Data Collection, Sorting and Analysis

Data collection, sorting and analysis should be given special attention as it directly related to the quality of the assessment and subsequent analysis. A computerized platform with data capture, storage, and analysis should be used. In general, the computer platform should be designed with the following attributes:

- GIS capable
- Mobile device compatible
- Multi-platform and multi-format capability
- Ease of data entry (user interface is key) and retrieval
- Data validation and quality management
- Real-time risk analysis based on risk algorithms
- Data management strategy and administration

Corrosion Mitigation and Cathodic Protection

Cathodic protection is a method in which a sufficient amount of electrical DC is continuously supplied to a submerged or buried metallic structure to mitigate, slow down or temporarily stop the natural corrosion processes from occurring. CP systems pump electrons into the structure thus protecting them. There are two methods for supplying DC to protect a structure cathodically: a galvanic or sacrificial anode CP system, and an impressed current CP system. The designs are based on an empirical model that may consider current and potential distributions. Wrong currents and anode positions may lead to unprotected or under protected areas. Optimization methods combined with the boundary elements technique have become a useful tool to analyze such situations. The following items should be considered in the analysis:

- Concrete encasement cannot be ignored with regard to the mixed potential that results in varying current demand.
- Mill-scale coated structural steel (because of corrosion) under the lattice can be anticipated, as this may be proportionally higher since the mill scale is even more electropositive than copper grounding.

- On a below grade structure that is galvanized, not coated, the potential difference between the mill scale and zinc is higher.
- Many structures do not have a protective coating at all.
- For high-resistance soils, only certain models are likely amenable to effective sacrificial CP design.
- Protection criterion for galvanized steel is different from that of carbon steel.

Structure geometry, soil properties, environmental parameters and structure coating are salient factors that should be included in any CP design tool.

This innovative, CP system is designed for electrically connected lines (with shield line) and includes placement of anodes adjacent to the copper ground grid and establishing an impressed current sufficient to shift the effective potential of the grounding grid. With impressed current applied to the grounding grid, the metal structures no longer "see" the grounding grid as a large electropositive cathode, which eliminates the driving force for galvanic corrosion. That means that corrosion induced by corrosive soils and copper grounding can be mitigated without the need to apply CP at each structure location. Structures protected from accelerated corrosion include:

- Copper Grounding
- Galvanized Steel Structures
- Weathering Steel Structures

The above system can be applied provided electrical continuity exists and stray current issues are considered in the design.

Corrosion Mitigation Case History

On-Site and Laboratory Testing of Aging Galvanized Poles with Corrosion Below-Grade and Application of System Wide Cathodic Protection

Accelerated corrosion on several galvanized steel utility poles was observed by a public electric utility, and a field and laboratory study was undertaken to determine the root cause of corrosion. Testing included excavation, photographic documentation, detailed electrochemical-potential field measurements, corroded galvanized steel metallurgical characterization, determination of the galvanized steel poles' corrosion rate, continuity testing and laboratory soil characterization. Enhanced corrosion effects from soil characteristics depend on low soil resistivity, the presence of corrosive ions and on the impingement of water tables — and other sources of moisture — on the embedded steel structure. A light microscopic and scanning electron microscopic-energy dispersive spectroscopic (SEM-EDS) analysis revealed several structures with the worst corrosion still had a galvanized coating protecting the underlying steel substrate. This means not all zinc was corroded and there was some protection present.

Service Life

Several factors affect the service life of buried steel utility pole structures:

- Service environment, including soil type and water table corrosivity
- External influences, including grounding effects, stray corrosion currents and weather factors
- Age of a structure
- Presence or absence of coating and CP.

Some direct-embedded steel poles and towers corrode quickly as a result of natural and manmade environmental effects. This is primarily because of corrosive soils and galvanic action, or dissimilar metal corrosion. Field inspections and studies have led to some interesting observations about corrosion activity. First, the copper used as grounding at substations can corrode. This is a serious safety issue. Galvanized poles and galvanized anchors corrode through galvanic effects. Shield wires make the lines electrically continuous. A balanced state that prevents corrosion can be induced by CP controlled by a rectifier. To inhibit corrosion to the greatest extent, CP should be deployed the full length of lines from substation to substation. See Figure 7.

Through its investigation, the utility came to the following conclusions:

- Galvanized anchors and poles exhibit corrosion due to soil corrosivity, copper grounding and stray currents.
- Soils and water tables are corrosive and, in certain locations, may induce extreme accelerated corrosion.
- The copper grounding at substations in corrosive soils adds to the corrosion potential of affected structures and reduces their life expectancy.
- A system wide CP system can eliminate the adverse effects of corrosive soil and copper grounding on protected structures and add relatively maintenance-free service life to a protected line.

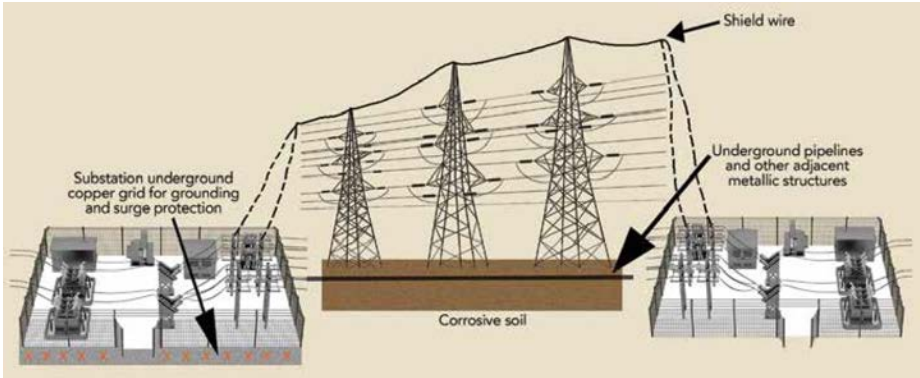


Figure 7: Typical causes of premature corrosion of direct-embedded galvanized steel poles.

Corrosion Protection

The utility's approach to protecting its galvanized steel utility pole structures involved implementing a system wide level of corrosion protection while emphasizing safety and the protection of assets at minimum cost. This approach was founded on the utility's ability to monitor all performance parameters in real time, by wireless telemetry and by providing access to collected data through the Internet. The solution for protecting the galvanized steel utility T&D structures at the substation level includes neutralizing the effect of copper while affording corrosion protection to the poles, anchors and copper grounding. See Figure 8.

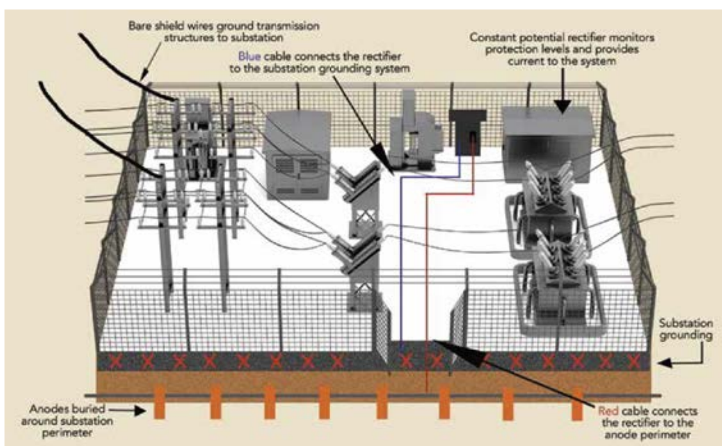


Figure 8: The CP system schematic for protecting galvanized steel transmission and distribution structures at the substation level.

The innovative CP system can be summarized as follows:

- A buried anode perimeter was established around the substation.
- The buried anode perimeter was electrically connected to the buried substation copper ground grid.

- An uninsulated overhead ground wire was continuously attached to each steel pole from one substation to the next.
- Separate cables connected the rectifier to both the substation grounding system and the anode perimeter.
- The rectifier measured differences in potential and impressed a balancing current into the system.

It is important to realize the criteria for CP differs for new and aging structures. This aspect is often not considered; therefore, potential measurements can be misinterpreted after the installation of a CP system. The zinc and intermetallic layers of galvanized steel exhibit an active potential compared to carbon steel, and very high negative potentials (>-1.2 V) induced by CP may corrode the zinc layer on brand-new galvanized steel. Another important factor for protection is the bare surface area. The CP system can protect a full line for many years in corrosive soils if the structures are fully or partially coated, or if additional ground beds are placed in between substations.

Protection Trials

The utility conducted CP trials at three substations. Initial work included conducting potential surveys at the substations and at the poles between substations. This included both native and polarized potentials. Polarization methods were used to analyze the effect of CP on the reduction of corrosion current and increase in life expectancy of the galvanized poles in corrosive soil. Wireless corrosion reference electrodes were used to monitor the CP system. See Figure 9.

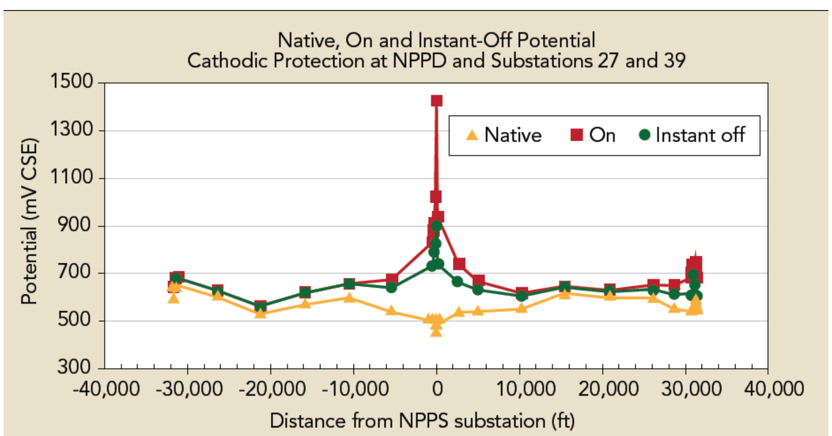


Figure 9: CP data for the three substations shows shift in potential of approximately 50mV indicating extending life for 30 to 40 years in low soil resistivity (2000 ohm-cm) areas.

An important aspect of this project is that the utility was among the first in the electric utility industry to implement wireless corrosion monitoring. The system collects and analyzes corrosion data from sensors or CP equipment at the site, and automatically passes that data to a web data center. The information is converted into alert messages, indicating changes of conditions at the site, along with regularly scheduled measurement data for archiving system wide CP system performance. As a result, users may access historical corrosion information and view graphical displays of corrosion activity.

Based on results from its trials, the utility has seen a substantial increase in the remaining life of its galvanized structures because of CP. If the poles are not coated by organic coating, additional CP may be required in between substations to provide adequate protection on poles distant from substations.

CONCLUSION

The corrosion prioritization program for electric power utility T&D structures may be developed based on the following:

- Age
- Geographical Region and In-Service Condition (corrosivity of environment)
- Circuit Condition Criticality
- Potential Impact of Structural Failure
- Galvanized Steel Vintage and Quality

Early on, or at later stages of service if galvanized structures exhibit accelerated corrosion, the following considerations may apply:

- Protective coating and CP can prevent thickness loss and extend life of the galvanized structure.
- However, if corrosion progresses to structural corrosion, load bearing members may need to be replaced to protect the integrity of the structure.
- Therefore it is important to assess and mitigate the corrosion before it becomes a structural issue and hazard.

REFERENCES

1. Laboratory and Field Corrosion Investigation of Galvanized Utility Poles. Authors: Authors: M. Zamanzadeh; C. Kempkes, D. Aichinger, D. Riley. Presented at ASCE Electrical Transmission Conference, Oct. 17, 2006
2. Corrosion Risk Strategies for Below-Grade Foundations of Transmission and Distribution Structures – Parts 1 and 2. Authors: Zamanzadeh, M; Jackson, Journal Name: Materials Performance April, 2014.
3. Laboratory and Field Corrosion Investigation of Galvanized Utility Poles. Authors: Authors: M. Zamanzadeh; C. Kempkes, D. Aichinger, D. Riley. Presented at ASCE Electrical Transmission Conference, Oct. 17, 2006
4. Don't Bury Your Problems. Authors: S. Fagot, M. Zamanzadeh, G. T. Bayer; T&D World, February, 2015

"HIVIZ" DIGITAL OBLIQUE IMAGE INSPECTIONS

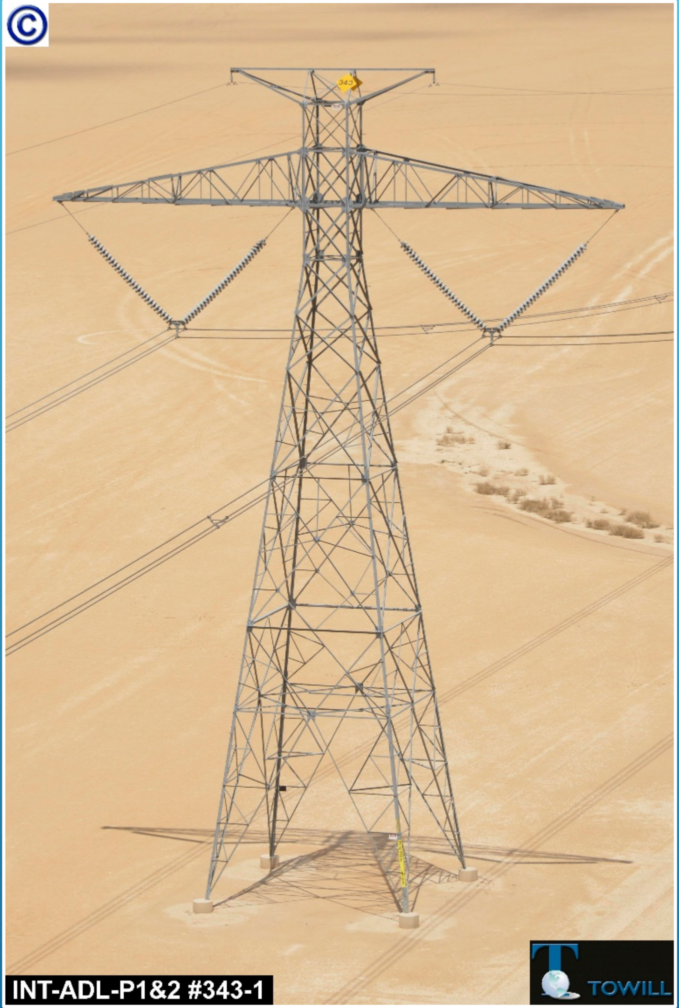
TSDOS MEETING SEPTEMBER, 2015

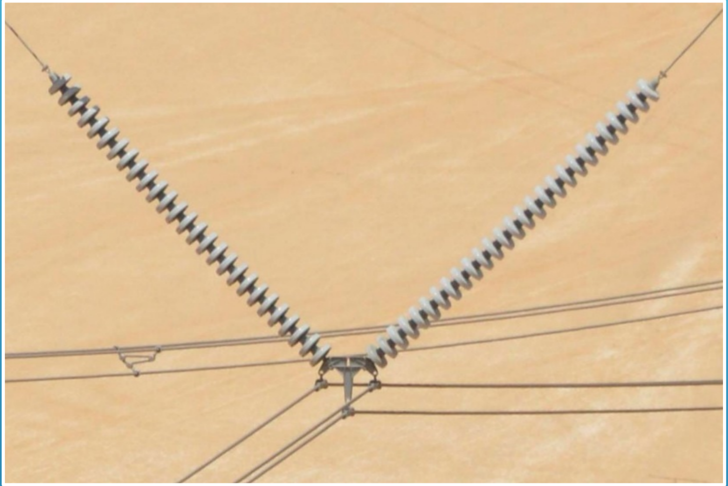
TOWILL

TSDOS

METHOD 1- POINT & SHOOT

- Point and Shoot – Still Camera

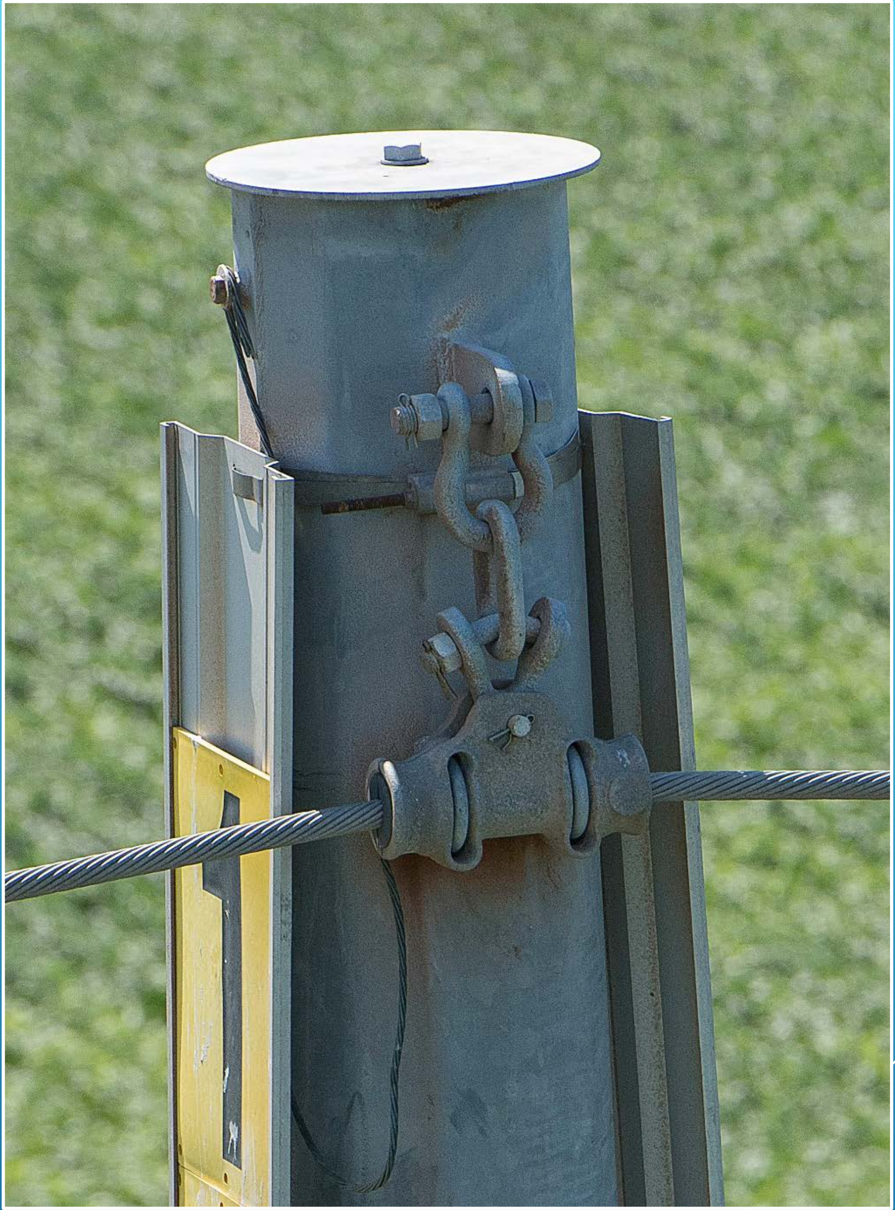




- Point and Shoot
  - Advantages
    - Fast - up to 50 knots
    - High Resolution – 36 mp
    - Images with extensive zoom capability
    - Can't see fine detail without slowing and/or zooming

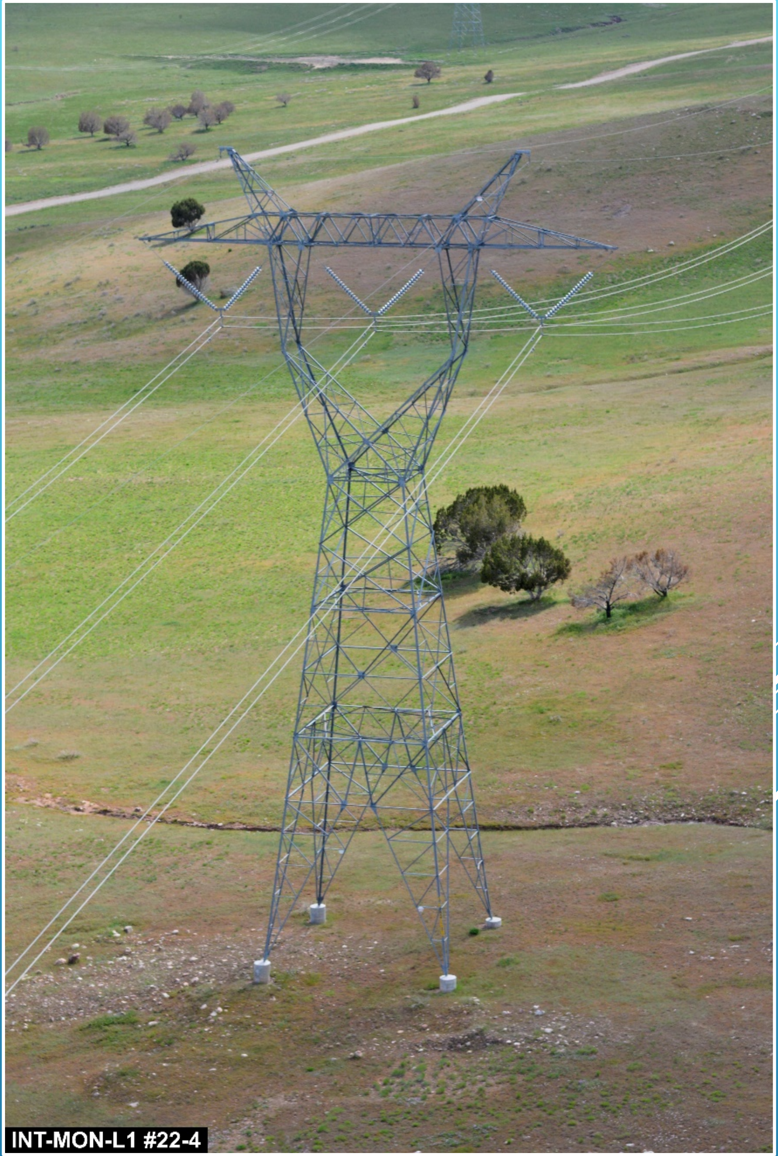
METHOD 1- POINT & SHOOT

- Point and Shoot
  - Advantages
    - If you slow down high resolution is possible

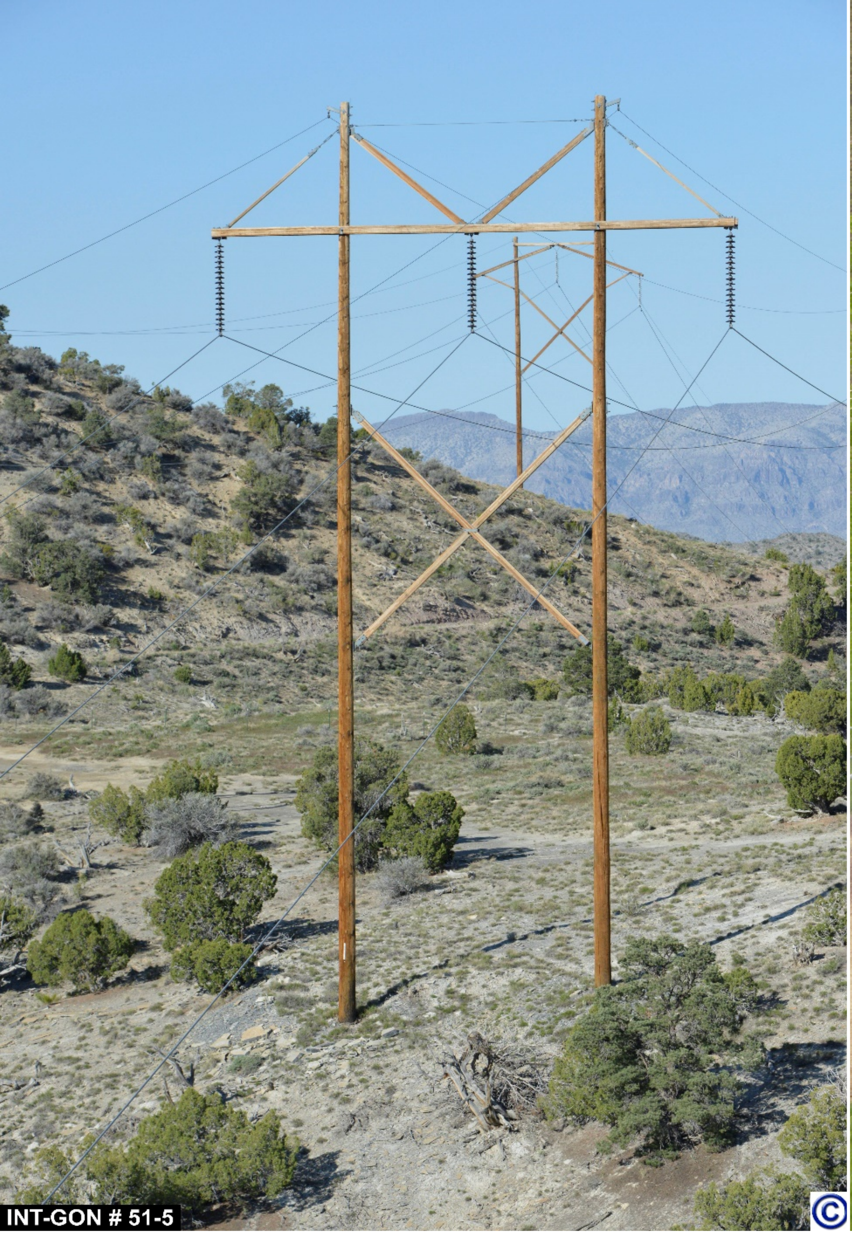


METHOD 1- POINT & SHOOT

- Point and Shoot
  - Disadvantages
    - Must remove door - Safety
    - Photographer must have clear view
    - Hover requirements for fine detail



METHOD 1- POINT & SHOOT



METHOD 1 SAMPLES

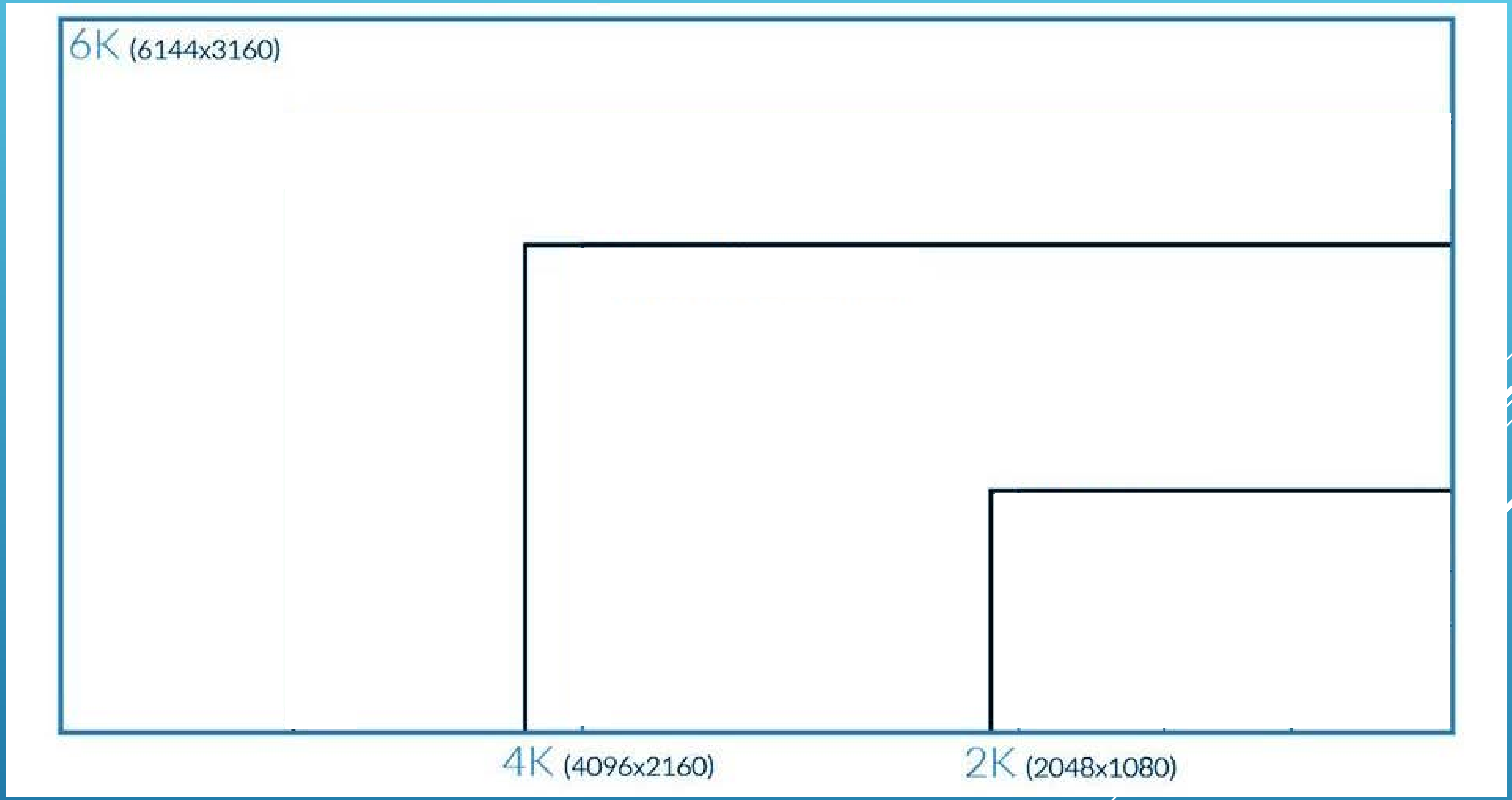
- Helicopter Mounted Digital Video

METHOD 2 – “HIVIZ” VIDEO

- 5 Axis Gyro Stabilization (this is an attached video)

METHOD 2 – "HIVIZ" VIDEO

- Comes in three flavors
  - HD (2048 – 1080)
  - 4K (4096 – 2160)
  - 6K (6144 – 3160)

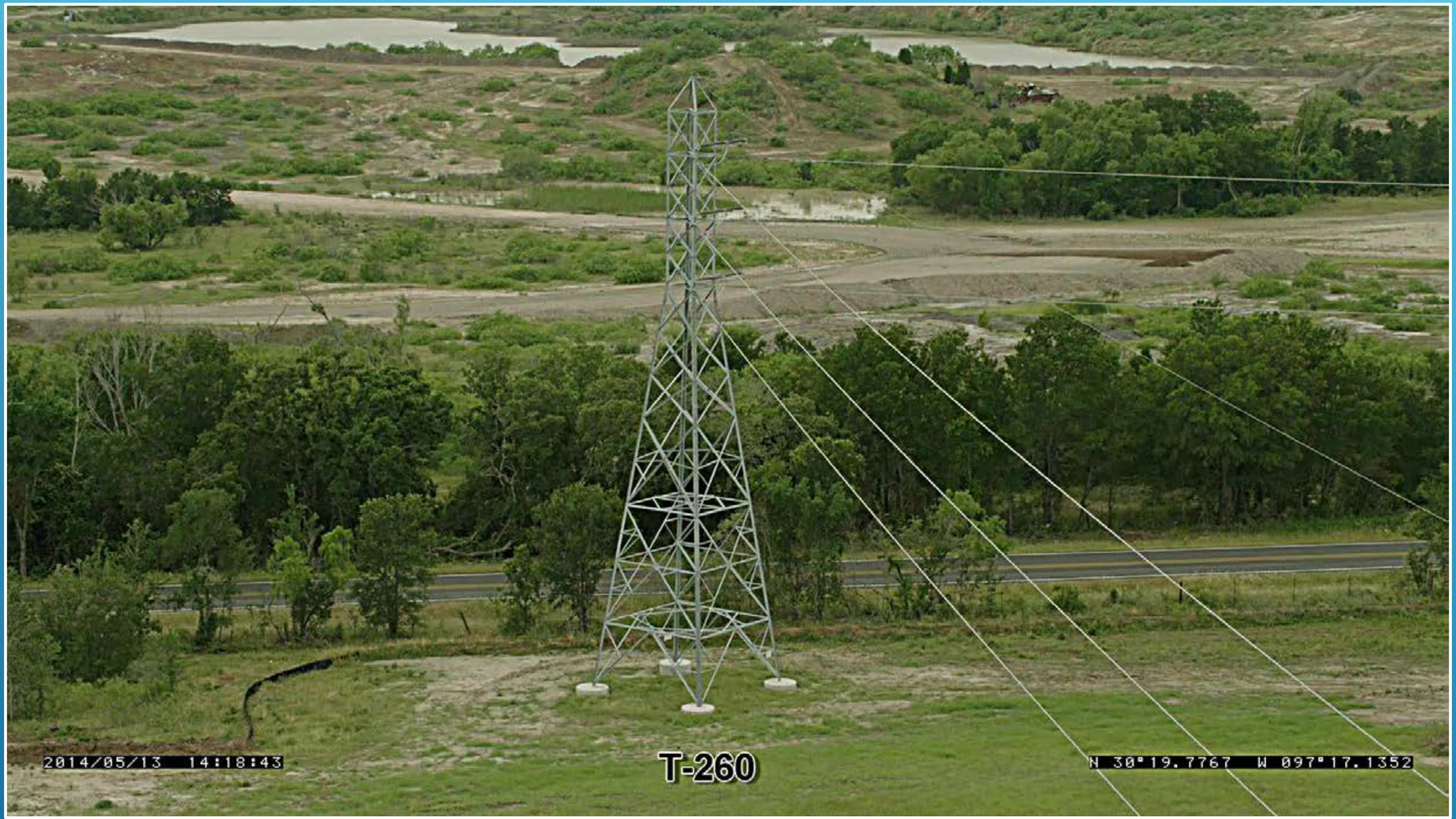


METHOD 2 – "HIVIZ" VIDEO

- 2K (2048 – 1080)

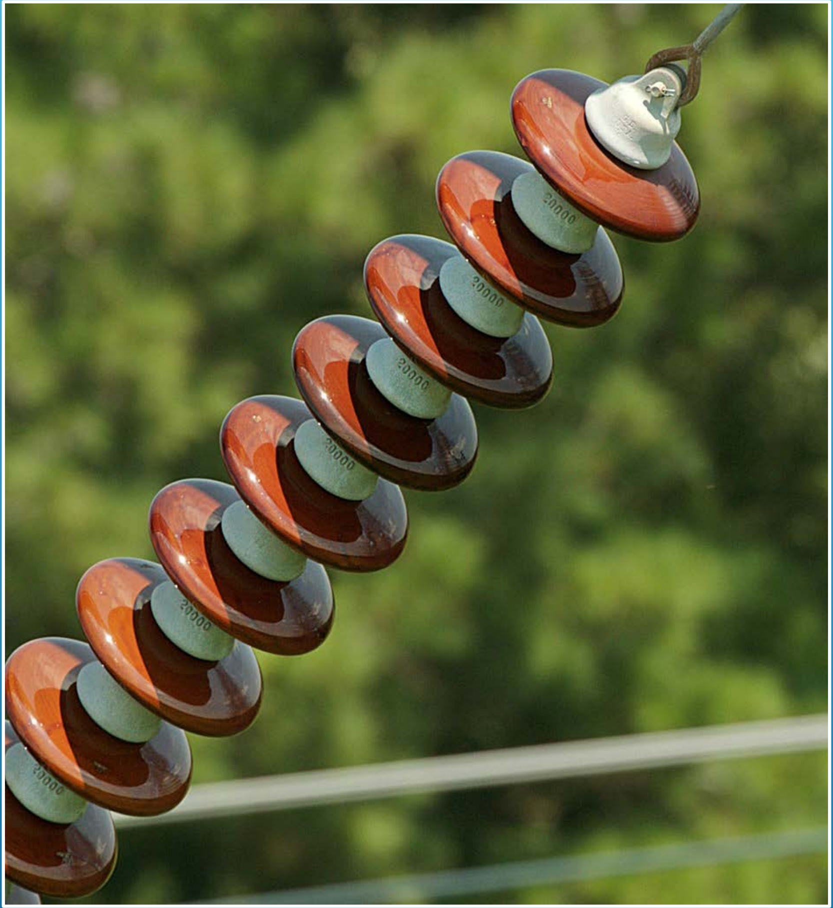
METHOD 2 CAPABILITIES

- 4K (4096 – 2160)



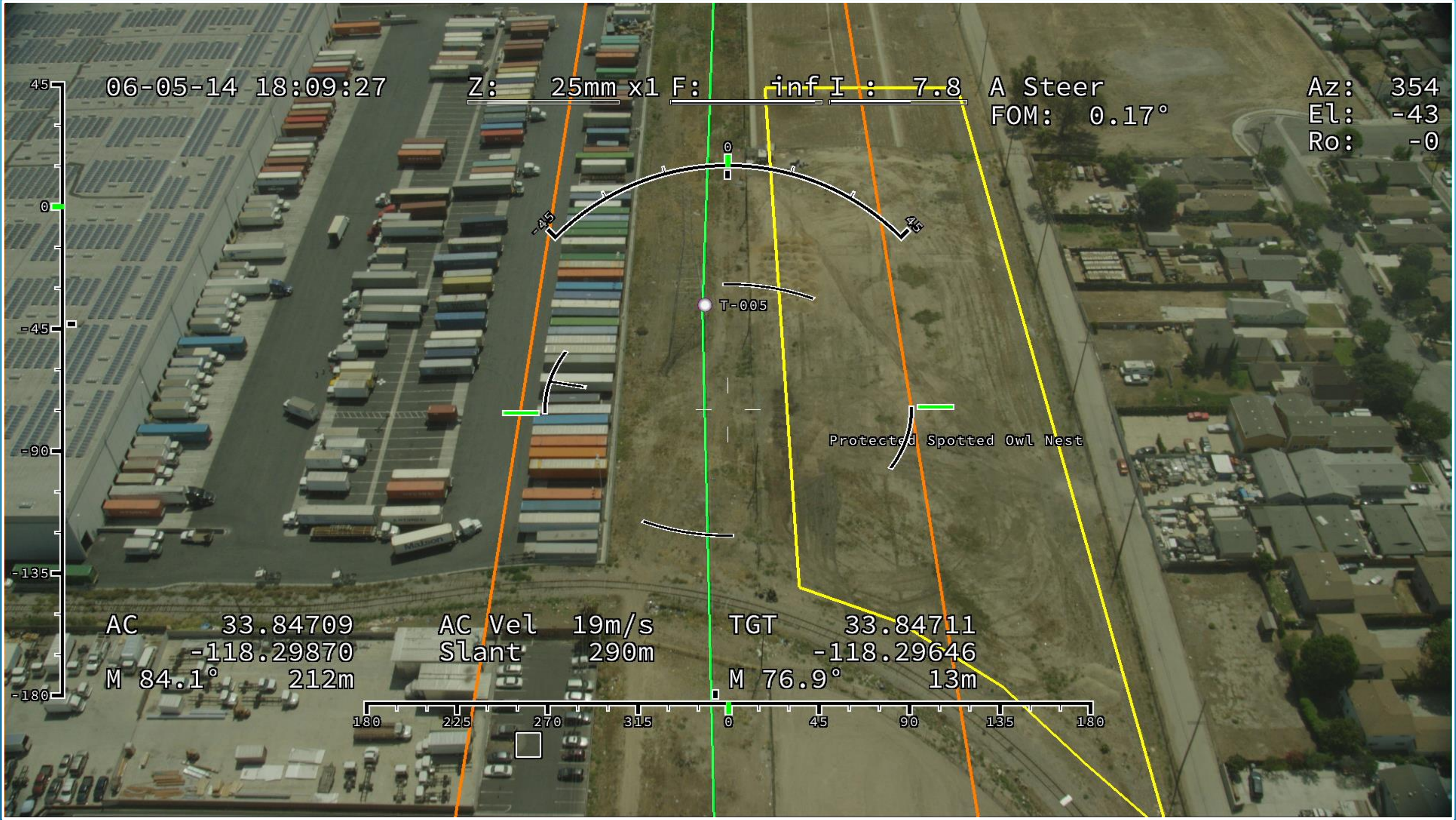
METHOD 2 CAPABILITIES

- 4K (4096 – 2160)



METHOD 2 CAPABILITIES

- 6K (3160 – 6144) – Add Vector Data Into Video



METHOD 2 CAPABILITIES

- Speed
  - Hours vs days/weeks
- Safety
  - No climbing structures
  - No off-road driving
  - Inspection completed in office
- Public Relations
  - Won't know we were there
  - No transfer of noxious weeds/materials

BENEFITS

- Structure Climbing

- "HiViz" Digital Video

COMPARISON

- Cost per structure - Dependent on Several Factors
  - Length of alignment(s) - Up to 150 miles in a day
    - More time if lines of interest are spread out
  - Complexity of Structure
    - More time for lattice tower vs. monopole
    - More time for double circuit vs. single
    - More time for urban vs. rural
    - More time for smaller voltages vs. larger
    - Items of interest – entire structure vs. insulators/connections
  - Helicopter biggest cost factor

COST

TSDOS

THE FUTURE

THANK YOU

How OSHA’s New Transient Overvoltage Requirements Affect Work Practices

By:

Baldwin A. Yeung, P.E., Electrical Engineer

Humberto Branco, Electrical Engineer

Leidos Engineering, LLC

July 30, 2015

leidos

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Abstract

This paper presents how the new Occupational Safety and Health Administration 29 CFR,§1910. 269 (OSHA 269) transient overvoltage (TOV) requirements affect a sample investor-owned utility (IOU) client's current safety approach distance to energized electrical equipment for transmission and distribution system. The new requirement could adversely impact many of the industry's current work practices as regulations go into effect January 31, 2016. It is anticipated that, if a utility solely utilizes the conservative TOV values supplied by OSHA without performing the appropriate an engineering analysis, then working distances will increase to values much greater than current working distances. The distances at high-voltage equipment may increase 50 percent or greater. Thus, prior to the deadline, utilities have the option of using the OSHA stipulation stating that, if the utility performs an engineering analysis using an electromagnetic transient program such as PSCAD or EMTP-RV, the amount of TOV could be reduced and consequently the MAD is decreased.

In 2014, OSHA updated its 29 CFR Parts 1910 and 1926, commonly referred to as the "269 Standard," which entails implementing new OSHA rules for electric power generation, transmission, and distribution, electrical protective equipment. Specifically, OSHA's update affects many electric utilities' MAD to energized equipment greater than 72.5 kV. As stated in OSHA 269 Paragraph (c)(1)(ii) of§1926.960, OSHA "requires the employer to determine the maximum anticipated per-unit TOV, phase-to-ground, through an engineering analysis or assume a maximum anticipated per-unit TOV, phase-to-ground, in accordance with OSHA Table V-8, which specifies the following maximums for AC systems."

Furthermore, if the TOV remains above OSHA's threshold, mitigation could be evaluated. A significant associated concern is that arc flash studies are dependent on TOV distances and consequently values will need to be recalculated to align with the TOV study. In other words, there is a resultant push-pull scenario between TOV and arc flash to help shape the future of safety distances to energized equipment. All substations over 69 kV will be needed to be analyzed for TOV and arc flash in order to be OSHA-compliant.

1. Introduction

The new Occupational Safety and Health Administration 29 CFR,§1910. 269 (OSHA 269) transient overvoltage (TOV) requirements have prompted electric utilities to re-evaluate their present minimum approach distances (MAD) to energized electrical equipment for substations and transmission lines. The new requirement could adversely impact many of the industry's current work practices as regulations go into effect January 31, 2016. It is anticipated that, if a utility solely utilizes the conservative TOV values supplied by OSHA without utilizing an engineering analysis, then the MAD will increase to values much greater than present MAD. The distances at high-voltage equipment may increase 50 percent or greater. Thus, prior to the January 31 deadline, utilities have the option of using the OSHA stipulation stating that the revised provisions on MADs include a new requirement for the employer to determine maximum anticipated per-unit TOVs through an engineering analysis or, as an alternative, assume certain maximum anticipated per-unit TOVs (Paragraph c(1)(ii)). In other words, if the utility performs an engineering analysis using an electromagnetic transient program such as PSCAD or EMTP-RV, the amount of TOV could be reduced and consequently the MAD decreased. These software programs require careful consideration when modeling a utilities system. When simulating an event on the system, the amount of trapped charges on the studied line and time for the charges to dissipate directly affect the TOV calculations.

To demonstrate this point, the remainder of this paper discusses the tools to successfully meet the OSHA compliance requirement. This paper presents compliance considerations, TOV modeling, studies and assumptions, simulations, and mitigation of OSHA's 269 TOV requirements.

2. Compliance Considerations

In 2014, OSHA updated its 29 Code of Federal Regulations (CFR) Parts 1910 and 1926, commonly referred to as the "269 Standard," which entails implementing new OSHA rules for electric power generation, transmission, distribution, and electrical protective equipment. Specifically, OSHA's update affects many electric utilities' MADs to energized equipment greater than 72.5 kV. As stated in OSHA 269 Paragraph (c)(1)(ii) of§1926.960, OSHA "requires the employer to determine the maximum anticipated per-unit TOV, phase-to-ground, through an engineering analysis or assume a maximum anticipated per-unit TOV, phase-to-ground, in accordance with Table V-8, which specifies the following maximums for AC systems." Minimum approach distance can be defined as the distance, based on voltage involved, that an unprotected 269-qualified employee must maintain when exposed to energize parts.

As presented in Figure 1 below, the OSHA-recommended MAD values do not significantly differ from a MAD values for voltages less than 230 kV. Leidos investigated this issue for a mid-sized investor-owned utility (IOU) client. At high voltages, consideration on the impact of a utilities MAD would need to be evaluated to determine compliance.

Figure 1. Minimum Approach Distance Comparison

Voltage (kV)	Mid-Sized IOU MAD (ft)	OSHA Calculated Phase-to-Ground (ft)	OSHA Calculated Phase-to-Phase (ft)	OSHA TOV Recommendation (p.u.)
12	2.16	2.13	2.23	--
69	3.16	3.28	3.94	--
138	3.58	4.30	5.40	3.5
230	5.25	5.60	8.40	3.5
500	11.25	16.6	27.00	3.0

ft = feet
p.u.= per unit

As indicated in OSHA's Table 13 in Figure 2 below, the TOV (p.u.) values dictate the MAD distances. The greater the per-unit TOV, the greater the MAD that OSHA recommends for compliance. As such, in order to reduce the MAD to values close to industry standards, utilities would look for values between 2.3 and 2.4 at the 420.1 kV to 550.0 kV range.

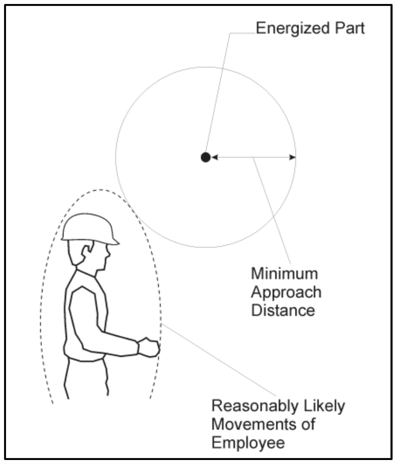
Figure 2. OSHA Table 13 - AC Minimum Approach Distances 420.1 to 550.0 kV

T (p.u.)	Phase-to-Ground Exposure		Phase-to-Phase Exposure	
	m	ft	m	ft
1.5	2.0	6.4	3.5	11.4
1.6	2.1	6.9	3.7	12.2
1.7	2.3	7.5	4.0	13.2
1.8	2.5	8.0	4.3	14.1
1.9	2.6	8.6	4.6	15.1
2.0	2.8	9.2	4.9	16.1
2.1	3.0	9.8	5.3	17.2
2.2	3.2	10.5	5.6	18.2
2.3	3.4	11.2	5.9	19.2
2.4	3.6	11.9	6.2	20.3
2.5	3.8	12.6	6.5	21.3
2.6	4.1	13.4	6.8	22.4
2.7	4.3	14.1	7.2	23.6
2.8	4.6	15.0	7.5	24.7
2.9	4.8	15.8	7.9	25.9
3.0	5.1	16.6	8.2	27.0

m = meters
T=TOV
ft=feet

An additional consideration to the MAD values is the determination of the distances to the arc for voltages greater than 46 kV. As shown in Figure 3(OSHA Figure 1), OSHA outlines the MAD distance between the worker and the energized equipment. Previously working distances associated to arc flash and MADs were independent of each other, but OSHA 269 recommends calculating the proper arc flash personal protective equipment in conjunction with MAD.

Figure 3. OSHA Minimum Approach Distance



As seen in Figure 4, the new arc flash working distance for 46 kV or greater is calculated by subtracting the arc length from the MAD. Therefore, to accurately calculate arc flash hazard levels, the MAD values must be taken into consideration. Figure 4 below represents OSHA's 269 Table 14, which recommends that the arc length be calculated, using the formula: (2 x kV/10). Essentially, if the MAD is reduced then the arc flash calculation will need to be re-checked.

Figure 4. OSHA Table 14 - Selecting a Reasonable Distance from the Employee to the Arc

Class of Equipment	Single-Phase Arc mm (inches)	Three-Phase Arc mm (inches)
Cable	NA*	455 (18)
Low voltage MCCs and panelboards	NA	455(18)
Low-voltage switchgear	NA	610(24)
5-kV switchgear	NA	910(36)
15-kV switchgear	NA	910(36)
Single conductors in air (up to 46 kilovolts), work with rubber insulating gloves	380(15)	NA
Single conductors in air, work with live-line tools and live-line barehand work	MAD-(2 x kV x 2.54) (MAD-2 x kV/10)✞	NA

*NA = not applicable

✞The terms in this equation are:

MAD = The applicable minimum approach distance, and

kV = The system voltage in kilovolts

3. Modeling for TOV Evaluation

Transient overvoltage in electrical transmission and distribution systems can be a result from faults and network switching operations. TOVs are of very short duration (microseconds to milliseconds) and can be of large magnitude. In order to study TOVs accurately, we must use an electromagnetic transient software program with a frequency-dependent model capability such as EMTP-RV or PSCAD. Figures 4 and 5, derived from PSCAD and EMTP-RV, respectively, represent the line transmission model in the software.

Figure 5. PSCAD Model of Transmission Line

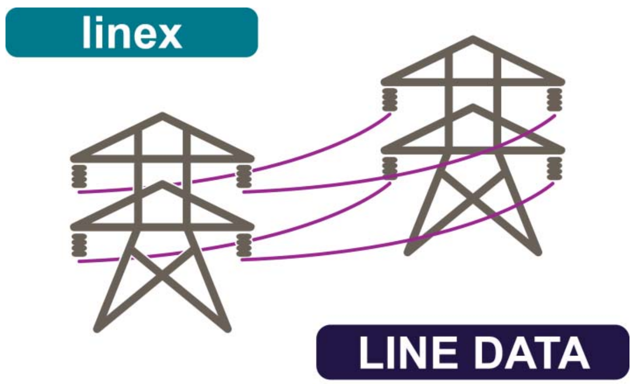
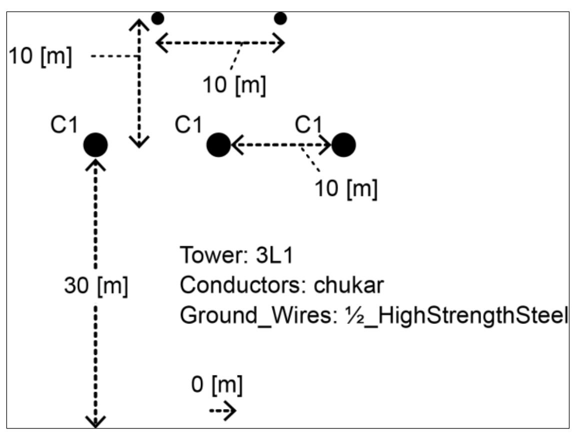


Figure 6. EMTP-RV Model of Transmission Line



Major considerations needed for building a TOV model are:

1. Line constant data
2. Network equivalents
3. Topology of the system.

Regardless of the software used, it is crucial to get the line-constant data. Typically, the user would be able to obtain the line-constant data from steady-state transmission software such as Electrocon's CAPE or Advanced System's ASPEN. It is also crucial to obtain the equivalent of the network, and such information could be obtained from a power flow program such as Siemens PTI's PSS®E and GE PSLF.

Once the above parameters are collected, the final consideration prior to modeling is to determine how many neighboring buses will need to be modelled. When studying TOV for a specific line in the system, neighboring transmission line capacitance is required to represent the system more accurately. Therefore, it is recommended to create a loop network around the studied line. Figures 7, 8, and 9 below were derived from modeling software to illustrate a typical network topology. The figures provide the user with an idea of the level of detail of the system would need to be modeled to perform TOV studies.

In order to accurately represent system current flows during fault and switching events a loop network is needed. A simplified partial model of the studied line, as represented in Figure 7, could produce unrealistic results. One of the issues would be to accurately simulate reclosing/energizing since the load side would have no energy supply under this radial representation. Another issue would be the loss of the entire system, which is not realistic for a network line.

Figure 7. Simple Model of Partial Line

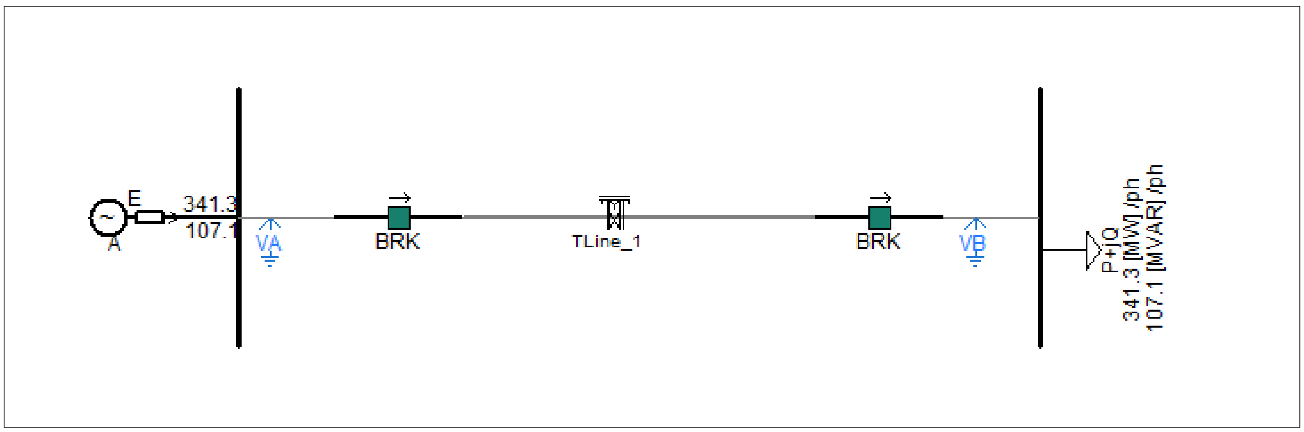
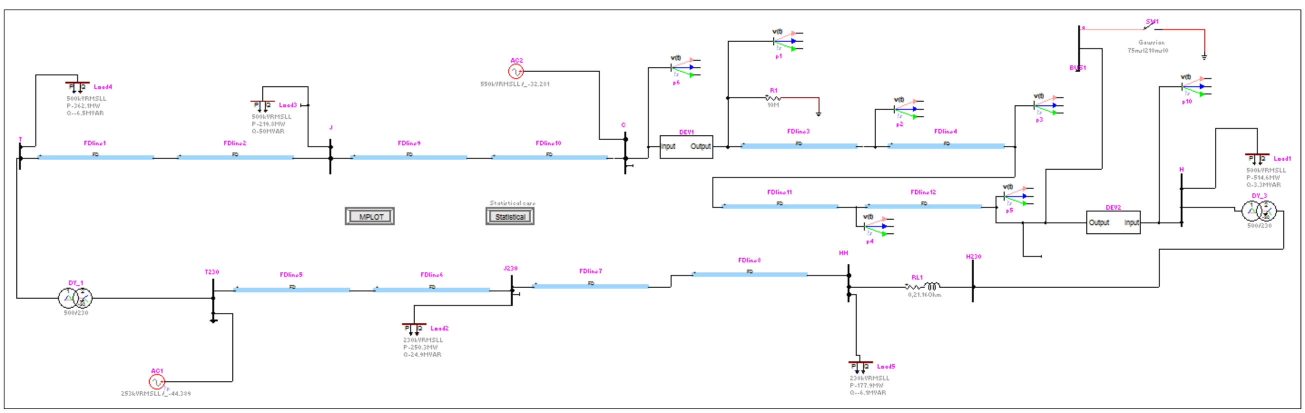


Figure 8. Detailed Model



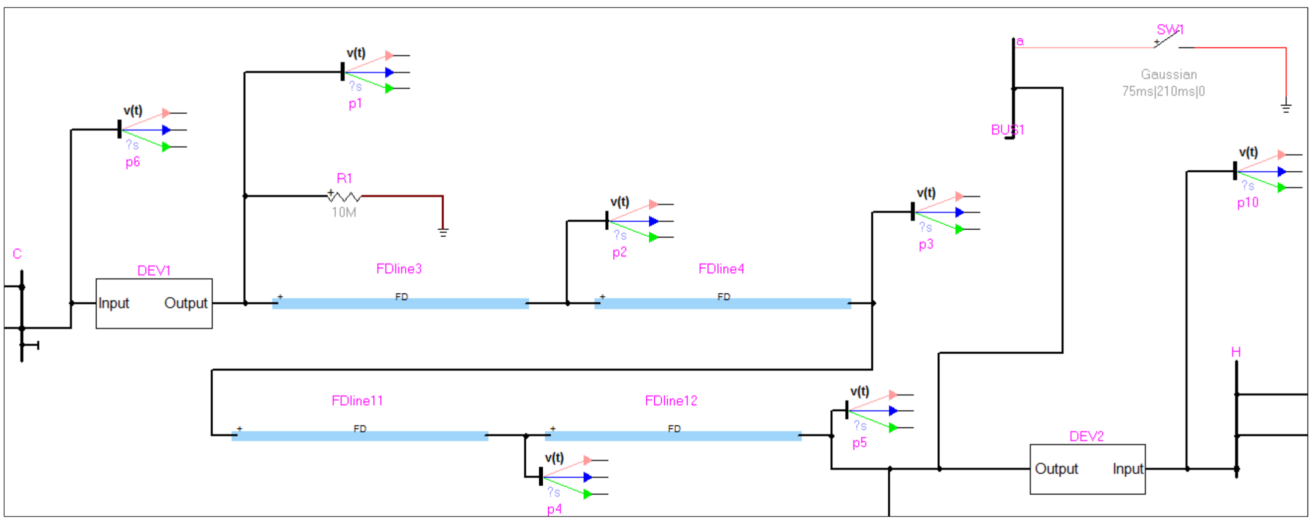
4. Studies and Assumptions

After creating and validating the model, it is important to determine the type of simulations and the location of the voltage measurements. It is recommended to split the study line into two to three segments at a minimum to effectively measure the TOV throughout the line into parts shown below:

- Local and remote substation (i.e., beginning and end)
- One-third
- Middle
- Two thirds

Figure 9 illustrates the four segments mentioned above. This approach helps identify the highest TOV captured at the line. Depending on the network and the location of the line, the worst TOV (i.e., the highest measurement) could be captured in different locations of the line. In other words, if only one measurement is taken, then we risk missing the worst TOV value.

Figure 9. Line Under Study Divided in Segments (Derived from EMTP-RV)



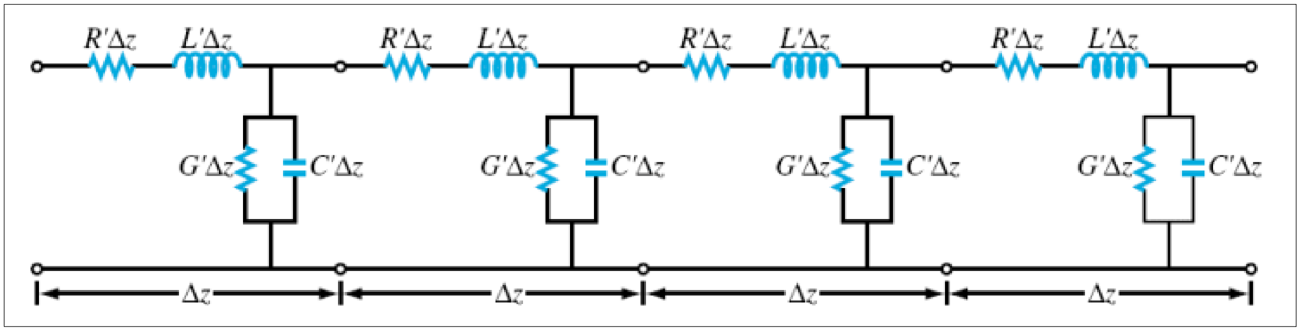
Different types of scenarios should be evaluated. The highest TOV could result from faults or de-energization. Therefore, it is recommended to perform the following simulations:

- Single-line-to-ground (SLG)
- Double-line-to-ground (DLG)
- Line de-energization

These three simulations should be performed under non-reclose and reclose scenarios. It is crucial to study high-speed reclose because the trapped charges on the line may not sufficiently dissipate which could lead to high TOV values.

A major consideration when performing TOV analysis is the shunt conductance value. Shunt conductance is a result of leakage current flowing across the insulators and air. Different software programs have different values that will yield significantly different TOV results. Therefore, it is important to investigate the most accurate value for the system under study. The value is complicated to calculate as it depends on many variables such as the type of insulator and the air quality. Utility-specific shunt conductance data is needed to accurately model the studied line.

Figure 10. Basic Transmission Line Model



Source: National University of Singapore, Department of Electrical & Computer Engineering.
https://www.ece.nus.edu.sg/stfpage/elehht/Teaching/EE2011%20Part%20B/Lecture%20Notes/Transmission%20Lines%20-%20Basic%20Theories.pdf

5. Simulation Results

The results of the simulation need to be compared with OSHA 269 table in order to accurately determine the MAD (Refer to OSHA Table 13 - AC Minimum Approach Distances 420.1 to 550.0 kV previously presented in Figure 2). This table is useful for utilities to determine mitigation if the distance is above the typical distance that the utility uses. An example of a double line to ground fault simulation is shown in Figure 11. In this example, the 2.42 p.u. TOV produced a MAD that was greater than a utility's present distances. The TOV value prompts the need for further mitigation strategies.

A result for the 500 kV line in Figure 11 represents a DLG fault measured at the side of the bus, indicating the highest TOV is 2.42 p.u. If no mitigation is implemented based on OSHA 269 Table 13 for 500 kV line, the MAD would be 11.9 ft. If 11.9 ft is high and the utility needs a smaller distance, the utility could consider revisiting the studies and proposal mitigation measurement in order to reduce the MAD.

Another example is shown in Figure 12, which represents a 500 kV line after an SLG fault measure at the side of the bus with a 30-cycle high-speed reclose. The graph shows the TOV reaching 3.55 p.u.; the highest voltage was evident after the reclose of the line. As mentioned previously in section 3-Modeling of the TOV, this phenomenon is a result to the insufficient time for the trapped charges to dissipate prior to re-energization of the line.

Figure 11. DLG Fault – Measurement at Line Side (Voltage Reach 2.42 p.u.)

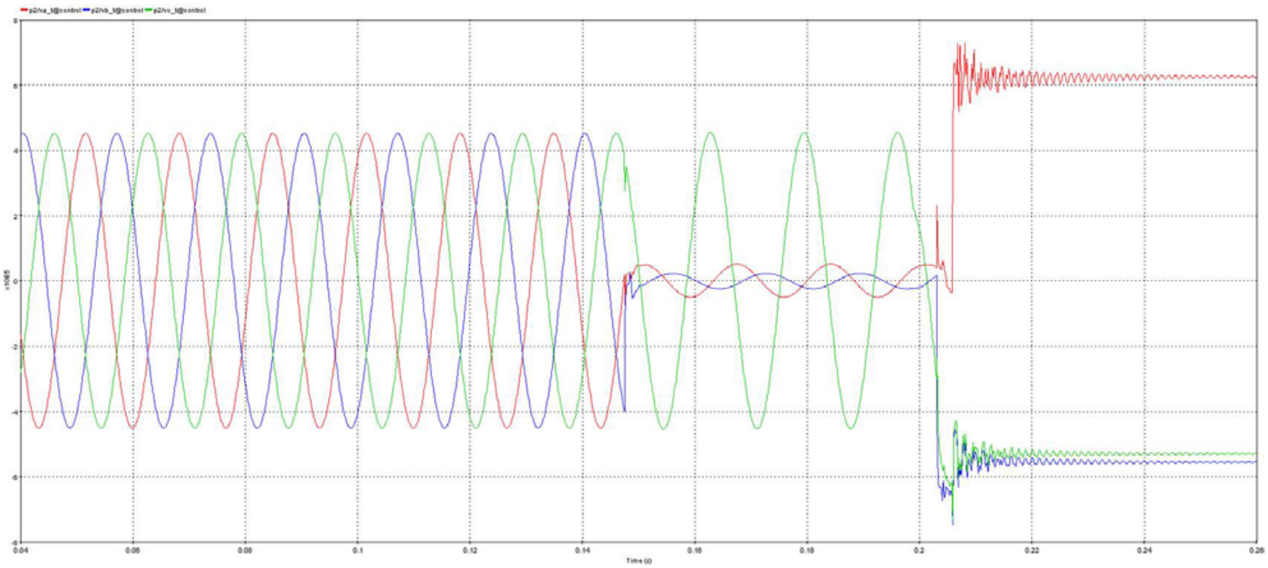
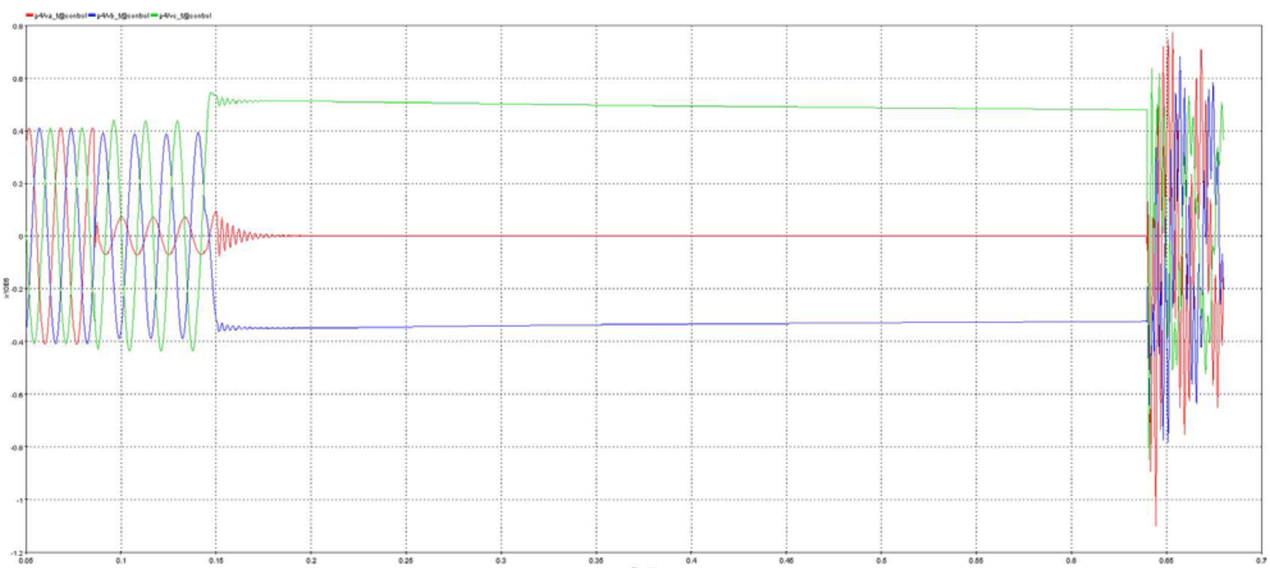


Figure 12. SLG Fault with 30 Cycles Reclose – Measurement at Line Side (Voltage Reach 3.55 p.u.)



6. Conclusion

OSHA 269 has added new considerations to determining a utilities MAD. The purpose of the engineering analysis is to ensure the present MAD distances are still within compliance. In the scenario that the TOV calculated forces a utility to possibly implement different mitigation strategies in order to maintain its present work practices.

There are a number of mitigation approaches that can be applied, depending on the severity of the TOV. For instance, TOV values above 3 per unit 500 kV would translate into MAD distances greater than 16 feet and would therefore warrant a mitigation approach that would significantly reduce the TOV, such as pre-insertion resistors or transmission system upgrades. The range of TOVs will affect utility workers' ability to approach energized equipment. If the present MAD distances are increased marginally due to the studied TOV values, the utilities may consider for example installing surge arrestors. In some instances where the TOV values are so significant that the MAD prohibits work near energized equipment.

A final consideration to mitigation would the high TOV due to high-speed reclose schemes. In order to reduce the TOV disabling the high-speed reclose could be a solution. if the decision is to remove the high-speed reclose, it is strongly recommended to perform a dynamic stability study to make sure that it would not have an inadvertent impact to the system.

All of the mitigation approaches discussed are valid. However, before implementation, a technical study as described above should be performed on a case-by-case basis to determine the best method and validate the proposed mitigation.

Improvements in Fault Location Capability at CenterPoint Energy to Reduce Response Time and Improve Accuracy of Fault Reporting

Presenter: Elias Marquez – Technical Consultant, Grid Performance, CenterPoint Energy

Co Authors: Michael J Pakeltis – Director of Transmission Operations, CenterPoint Energy
Jay Russell - Staff Technical Consultant, Grid Performance, CenterPoint Energy
David Cole – Technical Application Specialist, Qualitrol

Overview

As part of CenterPoint Energy's drive to reduce the response time to a line trip and gather more precise information to determine cause of fault, a program was initiated in 2006 to improve the accuracy and reporting time of fault location on the 345 kV and 138 kV networks. The project goal was to automatically deliver distance to fault results accurate to one span within minutes after a line trip to drive remedial actions and reduce downtime. This is not possible with impedance-based calculation techniques. The project has been ongoing for 9 years. The 345 kV network is now fully equipped. The 138 kV network is planned to be fully covered in the next two years.

This paper describes the double-ended traveling wave based system that is being deployed, the results achieved so far and the challenges that had to be overcome to extend coverage on the more complex 138 kV system. These include the management of multi-ended circuits, the development of a new sensor to collect the voltage component of the fault induced traveling wave on transformer tap circuits, and overcoming the effect of looped tees in a circuit. To date 129 devices have been installed in 119 substations monitoring 175 circuits. Sixty additional devices are needed to fully cover the network. Results so far have produced a reduction in the time to reach the actual fault site and more accurate identification of the cause of fault resulting in a reduction in the 'unknown' category of fault reporting. Accurate fault location has also been used to drive preemptive remedial work such as faulty insulator replacements based on locating repeated faults at the same tower.

Future work, as well as completing the deployment of the remaining units, will focus on the commissioning of a link to SCADA whereby fault results generated by the central server of the traveling wave system are automatically integrated into the SCADA host to drive automated responses. Enhanced signal processing will also be developed to improve accuracy of results for lightning events.

CenterPoint Energy Practice in 2006 – 345 kV and 138 kV Networks

CenterPoint Energy patrol guidelines after a line trip and sustained outage was to deploy ground and/or helicopter patrols, analyze fault location from DFR devices, run FALLS study, pinpoint location with patrols, implement repairs and submit a trouble report. The time to restoration was directly linked to how quickly the fault site could be identified.

The guide lines for a line trip and momentary outage was to analyze fault location from DFR devices, run FALLS study, deploy ground patrol next work day, pinpoint location with patrol, determine root cause, implement repairs if necessary, submit trouble report.

The primary fault location was provided by DFR devices using single-ended impedance functionality. Not every line end was monitored but at least one, and often two, devices would trigger for every fault. Following a line trip it was necessary for the DFR records to be downloaded to the Master Station, opened in the viewer and the distance to fault function enabled. Accuracy obtainable with single-ended impedance is variable depending on the type of fault and the degree of compensation included in the algorithm, for example mutual coupling on double circuit lines. The best accuracy on low resistance phase to phase faults is 1 to 2% of line length. For a 40 mile 345 kV line this equates to about 0.6 mile. However, on phase to ground faults with variable fault and zero sequence impedances and strong remote end infeed the error can reach 20% or 8 miles.

On 138 kV circuits where line lengths tend to be shorter, the physical error will be less but other factors will affect the accuracy. Information from relays was used as a backup, but data had to be downloaded by a relay technician from the substation site and emailed to others for analysis.

The effectiveness of finding the correct root cause, especially for momentary outages, is highly diminished without accurate fault locations. It is important to get to the site quickly to confirm some avian issues before any evidence is removed by scavengers and faulty insulators can be hard to detect without exact structure locations. Consequently many of the causes of fault in the trouble reports were 'unknown' making it difficult to initiate any follow up.

Improvement Goal

The improvement goal set in 2006 was to reduce the number of outages categorized as 'unknown' cause and further improve transmission reliability by getting to fault sites faster and initiating repairs.

There was also a concern that 'cause of fault' coding needed to be improved for the NERC TADS reporting for AC circuits ≥200 kV that was to commence in 2008.

The main contributors to the long response times to get to the fault site and failure to determine cause of fault was the low accuracy of the fault location method and the length of time needed for engineering analysis.

To meet the goal, a method was needed to automatically deliver distance to fault results accurate to one span within minutes after a line trip. The traveling wave method of fault location was considered the best method to achieve this goal.

Traveling Wave (TW) Method of Fault Location

Traveling wave fault location has been used on transmission lines for the last decade for accurate and consistent location of permanent and intermittent line faults typically to the nearest tower or span. The advantage of the technique is that it is not affected by factors that impair the performance of impedance methods like mutual coupling, changes in line impedance, fault resistance and far end infeed. All types of fault can be accurately located.

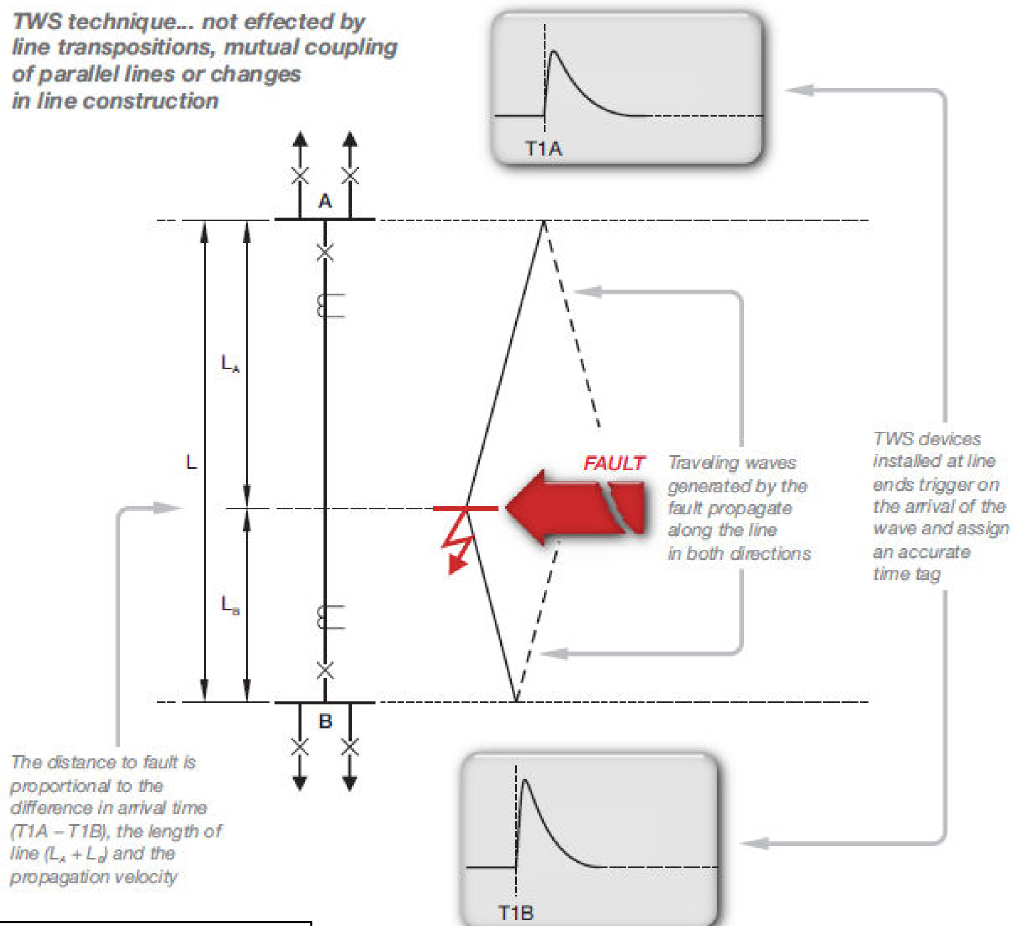
Modern traveling wave systems (TWS) use a double ended (Type D) method for fault location that does not rely on operator intervention to determine distance to fault. Results are automatically calculated and immediately available for use. The power arc at the fault site and the resulting step change in voltage generates a traveling wave that propagates along the line in both directions to the line ends. TWS fault locators positioned at the line ends accurately tag the arrival time of the waves using GPS as a reference. These time tags are sent to a central location where they are used to calculate distance to fault using the line length and the velocity of propagation. Further details are given in Figure 1.

The velocity of propagation is fixed provided the dielectric is constant along the route length. For overhead lines the dielectric is air meaning the velocity is very close to the speed of light, 186,000 miles / sec. The accuracy of the calculated distance to fault is set by the GPS time stamp assuming the line length is known. Earlier TW devices had an accuracy of 1µs with a resolution of 0.1 µs. Fault results accurate to 0.1 miles were achievable. TW devices released in the last few years have time accuracy of 100ns with a resolution of 10ns. These have the capability of returning better fault accuracy, the limiting factor now is knowledge of the line length and correct identification of the arrival of the TW at the line end.

As stated, communication is necessary between each substation and a central location. The minimum requirement is for the TW devices to upload the time stamp of each trigger logged. The central analyses software holds the circuit information and calculates distance to fault from the relevant trigger time stamps. Results are displayed in a filtered list view or sent as an email.

The communication overhead to transmit time stamps is low. However, the TW devices also capture TW waveforms for each trigger that can be used for manual off line analysis if required. These files are larger in size but only events of interest are downloaded to the central software for archiving / analysis.

To improve cost effectiveness it is possible to monitor up to 8 lines with one TW device.



LA = [L + (T1A-T1B).v] / 2

LB = [L + (T1B -T1A).v] / 2

Figure 1 Type D Traveling Wave Technique

Deployment on 345 kV Network

CenterPoint Energy first deployed the TW fault locators on the 345 kV network after a successful trial installation. This network consists of simple two ended circuits terminating in substations where other 345 kV lines are connected to the busbar. The presence of other lines at the circuit end results in a low terminating impedance compared to the line surge impedance meaning it is effective to monitor the current component of the traveling wave using split core linear couplers connected to the secondary of the protection CTs. The advantage of this method is that the sensors are non intrusive and can be installed with the circuit live. An example of a linear coupler installation retro fitted onto CT secondary wiring is shown in Figure 2.

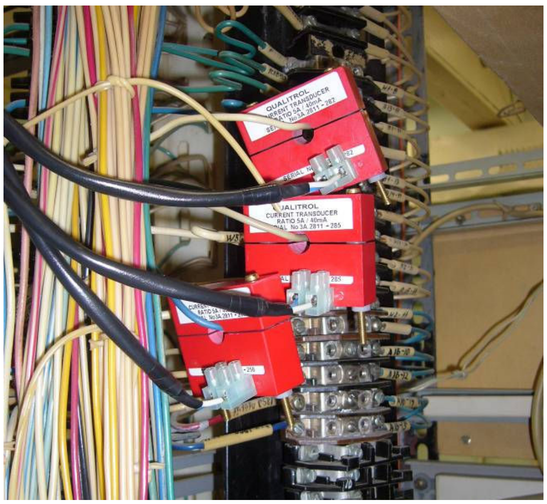


Figure 2 Linear Couplers Retrofitted to Protection CT Secondary Wiring

CenterPoint Energy uses telephone lines and dial up modems for communication between the central software and the remote sites. Although some network connections are now available it has been decided to continue with modem communications until the requirements to comply with NERC security standards are better understood.

The deployment of the TW devices on the 345 kV network was completed in 2010. Fifty four lines are being monitored by thirty three devices in thirty one substations. From 2008-2011, the 345 KV TWS network was successful in locating 93 out of 100 faults of which 56 had a confirmed cause of fault for the trouble report and 37 were unknown. The data was not available for 7 faults due to telecom or TWS hardware issues.

All results are analyzed by the Grid Performance Division in CenterPoint Energy. Circuits can be manually interrogated after a line trip to update results. In addition, devices are automatically polled on a daily basis to archive all events and check the health status of the System. Fault locations are routinely compared with lightning detection results from the FALLS system to better confirm the ‘cause’ of fault.

Deployment on the 138 kV Network

Based on the success on the 345 kV system, it was decided to deploy TW devices on the 138 kV network as well. Initially CenterPoint Energy deployed devices on the straight forward, interconnected, two ended circuits where conventional current monitoring of the transients produces good results. About 20 units have been installed per year since 2011. All communicate to the central station via modems.

However, the 138 kV system has more complex circuits as demonstrated in Figure 3. There are many instances of branches and tees resulting in multi-ended circuits as opposed to simple two-ended circuits. For full circuit coverage, it is necessary to monitor at the end of the branches as well as the main line. There are also instances when single lines terminate on transformers feeding local load. Such transformer feeders have a high terminating impedance compared to the line surge impedance meaning it is necessary to measure the voltage component of the traveling wave rather than current.

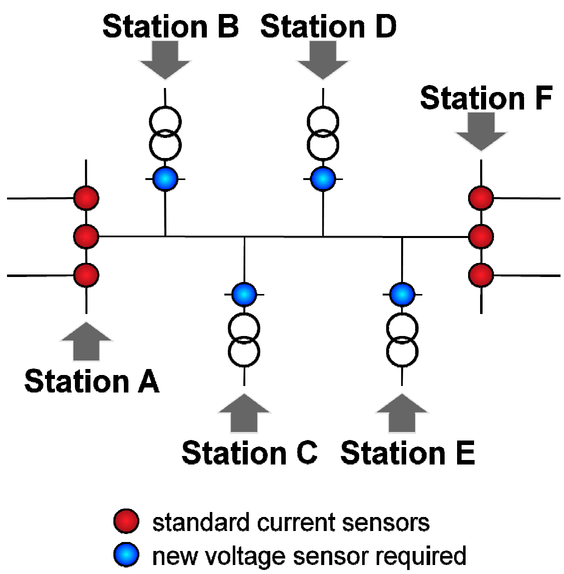


Figure 3 Typical Sub Transmission System with Transformer Feeders and Multi Ended Circuits

To allow full coverage of the 138 kV system, new analysis software was developed for the central station to allow the configuration and results analysis from circuits with up to six ends. One such six-ended circuit configured in the central software is shown below in Figure 4

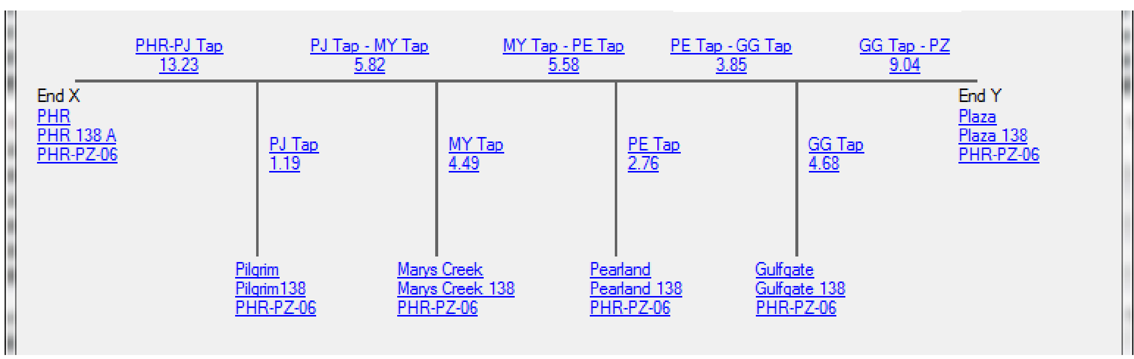


Figure 4 Six Ended Circuit Configured in the Central Software

The analysis software breaks the multi-ended circuit into each of the constituent two-ended circuits, calculates results from each of these and plots them on a graph. An example of an event during a lightning storm is shown below in Figure 5. Red circles denote results from different two-ended circuit combinations. TW devices positioned either side of the fault site will give the correct distance to fault. TW devices on the same side of the fault will give a location where the traveling wave entered the two-ended circuit being monitored. This is normally at a 'tee' position. The red cross marks the actual calculated fault site. A detailed distance is given in the list view where the faulted section is identified and, where possible, the length from each end of the main line and the closest monitored tee is given.

Note that due to attenuation of the traveling wave as it passes through each ‘tee’ point there may be instances where not all devices at the circuit ends will trigger for the same event.

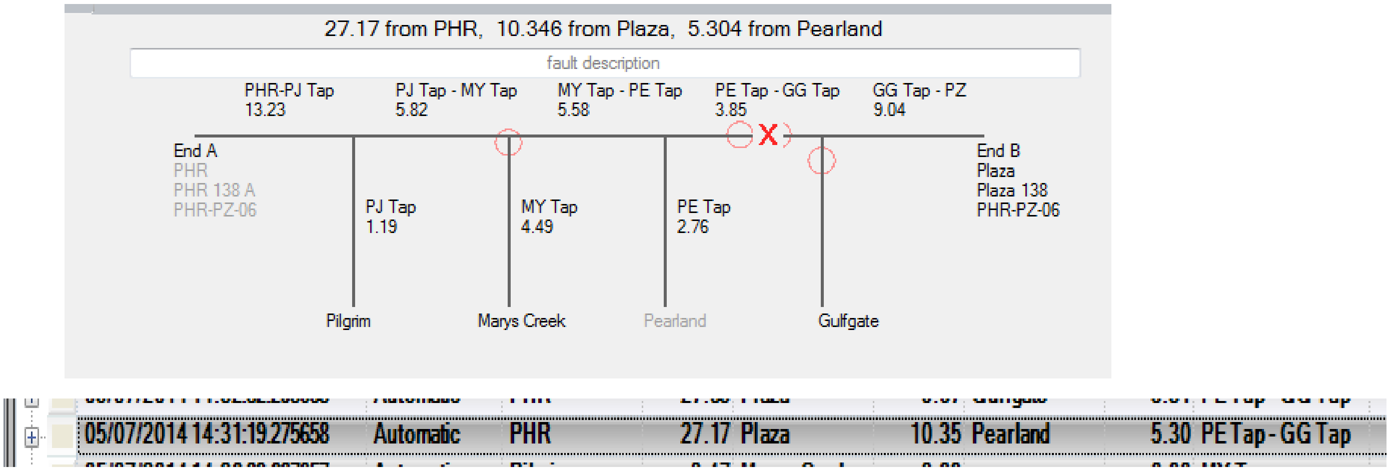


Figure 5 Results from a Lightning Event Plotted Graphically and a Listing of the Actual Site

In the above example many of the line ends being monitored are transformer feeders where the voltage component of the traveling wave is being monitored. To achieve this in a practical manner the resulting current from the voltage transient is being measured through the capacitance of the HV transformer bushing. A special coupler has been developed that fits to the test tap on the HV bushing and acts as the sensor providing a signal to the TW device. Most of the bushings so far encountered at CenterPoint Energy have been to the ANSI Type A standard. Pictures of the coupler are shown in Figure 6.

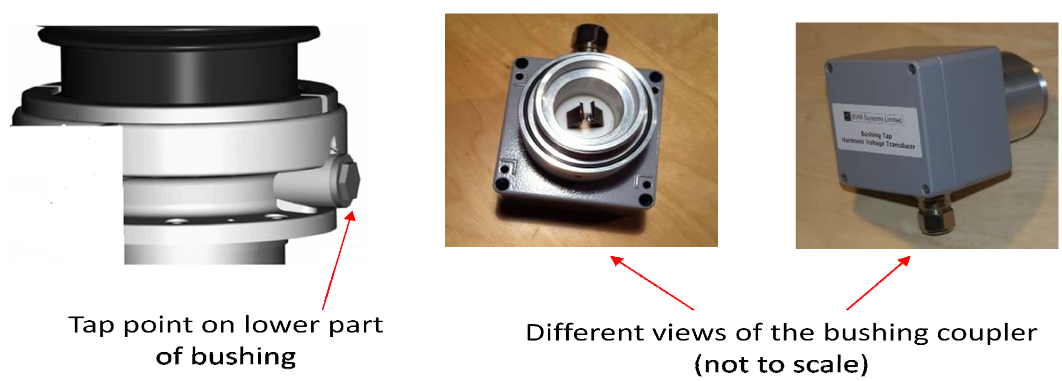


Figure 6 Bushing Coupler for ANSI Type Standard Bushing

Installation of the bushing couplers requires a line outage for fitting the couplers to the transformer, a marshalling box to combine the outputs of the three phase bushings and a new cable laid to the relay room to connect to the TW device.

About 70 transformers are being monitored in this way. Note that to date about five older transformers have been discovered on the system that have different types of bushing tap points that are smaller in diameter compared to the ANSI standard. A special adapter has been made to allow connection to these. Some oil filled Westinghouse bushings have also been discovered on some customer sites but there is no practical method at present to connect to these for permanent, on line fault location.

To date 96 TW devices have been installed on the 138 kV network in 88 substations covering 119 circuits. Another 60 are required to complete the deployment. Those circuits have had a total of 150 TWS fault events captured. With the exception of lightning events (see below) the observed accuracy is typically within 1-2 spans of the actual fault location.

Operational Experiences

For all voltage classes, the percentage of outages with an ‘unknown’ cause has reduced to 20% compared to 40% before the TWS fault location method was available.

One major fault on the 138 kV network, where a crane jib hit a line, highlighted a problem on a two-ended circuit containing one or more looped tees. Figure 7 illustrates a looped tee. It is where a line diverts to another substation and then returns back to the main line. Very often the start and end of the looped tee are on the same structure as the main line.

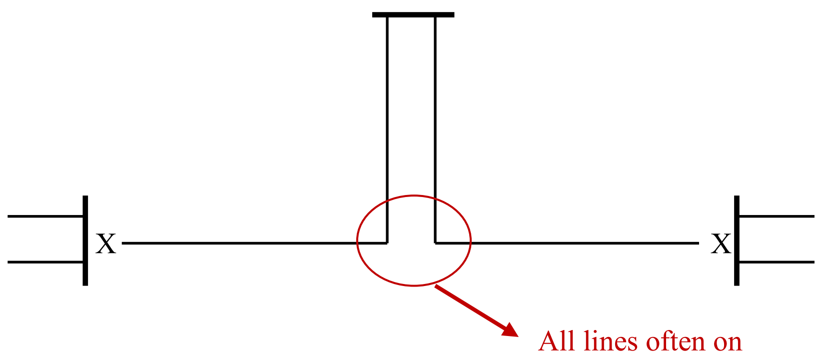


Figure7 Typical Looped Tee

The initial automatic distance to fault calculated when the crane hit the line had an error of 3.3 miles. The actual fault site was far from one side of a looped tee between the two ends of the circuit. After analysis of the circuit and TW waveforms, it was concluded the large traveling wave generated by the low resistance crane fault travelled to the structure with the looped tee and coupled across directly to the main line leaving the larger signal to propagate around the tee as expected arriving at the circuit end later than the coupled signal. The TW device triggered from the coupled signal rather than the main transient resulting in the error. Figure 8 illustrates this further.

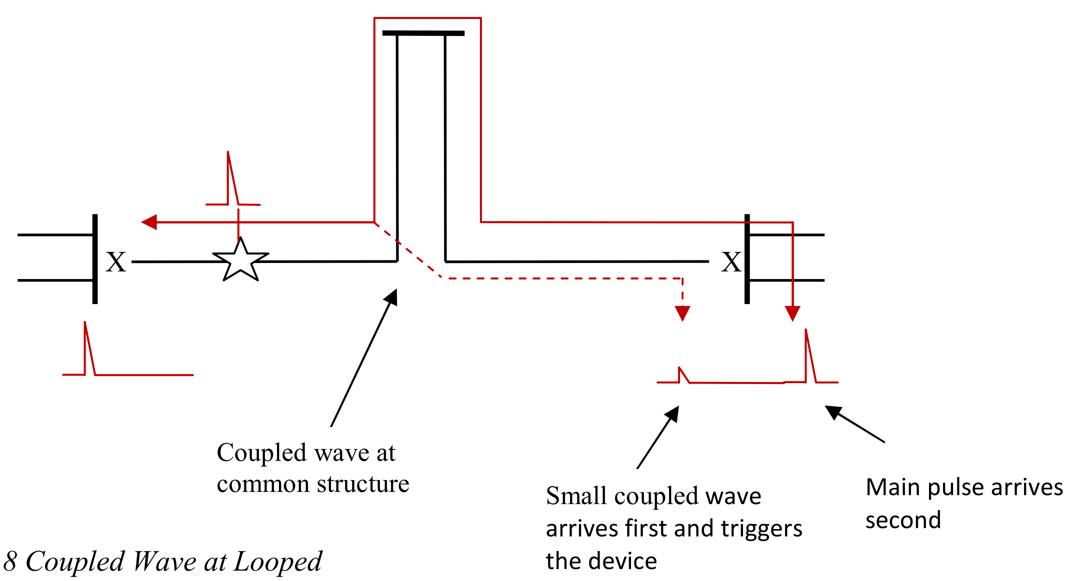


Figure 8 Coupled Wave at Looped

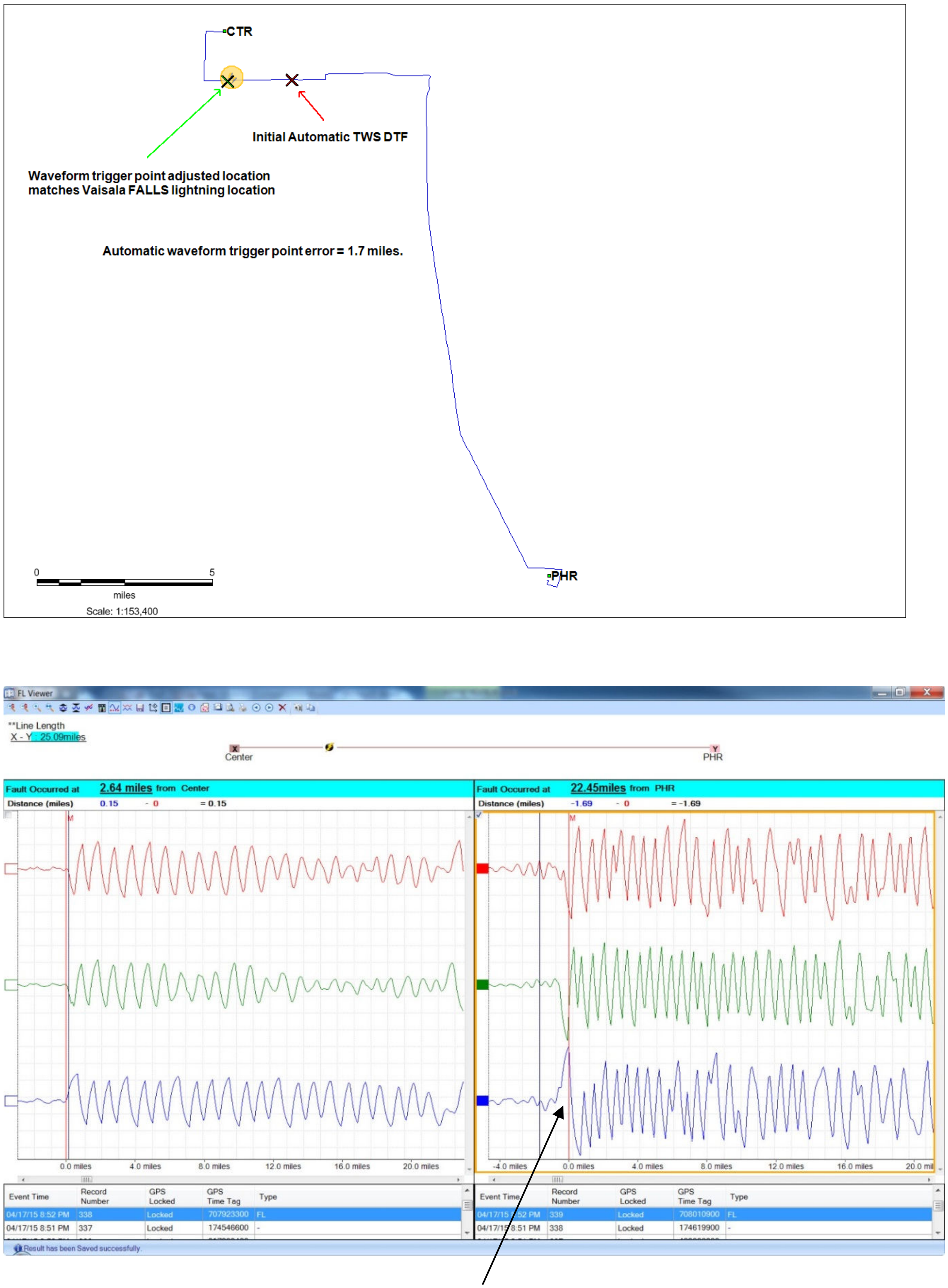
The TW waveforms for the crane fault are shown in Figure 9. The error of 3.3 miles can be accounted for by the difference in the trigger point between the first smaller coupled wave and the main pulse

Difference in Coupled Wave and Main Pulse Equates to Error in Fault Location of 3.3 miles

Figure 9 TW Waveforms from Crane Fault

One way to avoid this error occurring again is to add another TW device at the end of the looped tee dividing the single two-ended circuit into two separate circuits. However, when the 138 kV network was examined it was discovered that there were 51 circuits with looped tees but only 10 suitable monitoring points. Due to the costs involved and the lack of suitable monitoring points a software algorithm was developed to automatically compensate an error should coupling occur in the future. The algorithm is designed for a maximum of two looped tees at different points on a two-ended circuit. The compensated results for the crane fault are good, but more examples are needed in the future to fully test the solution. Note that only faults that generate large traveling waves are likely to result in coupling across a looped tee, and even then the magnitude will depend on the proximity of the circuits on the common structure.

It has been noted that certain lightning events have resulted in errors on the automatically calculated distance to fault of approximately 0.5 mile or greater. Examination of the TW waveforms has shown a small leading transient prior to the main breakdown. In many cases it is possible to manually adjust the trigger point to improve the fault location result. An example is shown in Figure 10. It is planned to assemble a library of these events that will be used to study the phenomena with the aim of producing an algorithm to automatically compensate the results. Lightning is an issue in the CenterPoint Energy operating area with 217,000 strikes being recorded in July 2014.

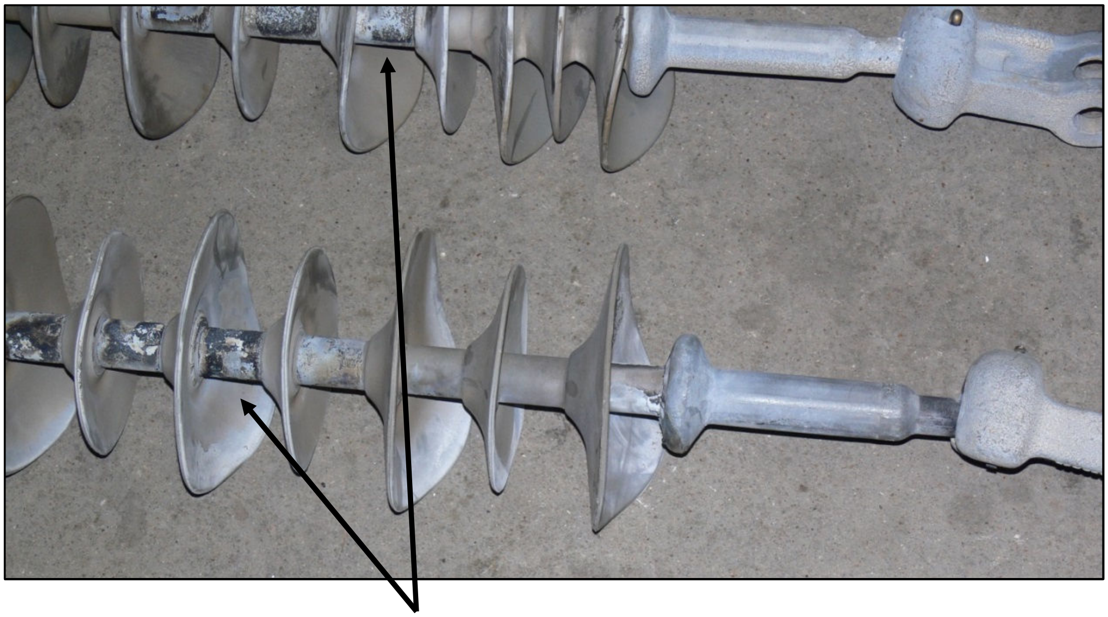


Manually Compensated Trigger Point

Figure 10 Circuit Details and Compensated TW Waveform for Lightning Event on 345 kV Circuit

Other Benefits of Traveling Wave System

Accurate fault location allows identification of specific insulator strings that flash and cause momentary outages. If this occurs multiple times at the same location then it is indicative of non recoverable damage meaning the insulators should be replaced before they cause a sustained outage. Figure 11 is a picture of damaged polymeric 138 kV insulators. The flash marks can be clearly seen when laid out on the ground but difficult to spot whilst still in service unless the specific structure can be identified for close examination.



Track Marks from Flashover

Figure 11 Photo of Flashed 138 kV Polymer Insulators

Future Link to SCADA

At present the results from the TW system are analyzed by the Grid Performance Division and passed on to the Control Room and patrol teams. The last stage in the automated link is to present results automatically in the Control Center.

The process to be deployed involves interface software that receives a signal from SCADA that a circuit has tripped. The TW software then polls the circuit ends, retrieves data and calculates the distance to fault. This value is then passed back to SCADA. Implementation is expected the end of this year.

Note that the latest version of the TW device contains digital inputs that can be used to monitor protection trip outputs. Activation of a digital input flags a significant event (a line trip). Any triggers that occur in a time window preceding the digital status change are marked as high priority and are automatically sent to the central software for analysis. This simplifies the process of automatic update of results minutes after a line trip but it is only available on the latest devices.

Summary

In 2006, CenterPoint Energy was faced with two problems. The first was the lengthy response times to pinpoint the fault site after a sustained outage. This meant it took longer to get repairs underway and longer to ultimately restore the line. The second was the low accuracy of fault locations made it difficult on momentary faults to know exactly where the fault occurred. This meant that at times it was not possible to determine a true root cause for an outage.

To address these issues a traveling wave system for fault location was first trialed and then deployed across the 345 kV and 138 kV networks to dramatically improve the locating accuracy. The TW installations have allowed for quick fault locations to be provided to the field patrols directly from the Control Center. The accuracy of the fault locations has been within one or two spans in many cases. A root cause is much easier to identify and is typically found by the patrols that can now take time to climb the one or two structures identified. For all voltage classes, the percentage of outages with an 'unknown' cause has reduced to an average outage rate of 20% compared to 40% before the TWS fault location method was available.

Future work will involve implementing a direct link with SCADA and developing an algorithm to compensate for some errors noted on some lightning events due to fast leaders before the main strike.

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Mobile Transformers & Substations (MTS) Flexibility and Safety

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48th Annual Transmission & Substation Design & Operation Symposium

The University of Texas at Arlington

Division for Enterprise Development

Mobile Transformers & Substations (MTS) Flexibility and Safety

Jeffrey Wimmer, Senior Member IEEE

***Abstract* --** This paper will address recommendations and best practices for MTS safety in contingency operations. MTS deploy and are commissioned in 12-24 hours. In a loss of service contingency MTS operations must effectively deploy within your organizations safety culture and guidelines. Safety considerations should begin at the specification level; what should be covered in the specification points? Further, capital expenditure for an MTS is significantly different than any other substation asset. What capacity (MVA). What Voltages – split primary/split secondary? Drive in or back in; connection to system. They are customized and they are by definition mobile - their inherent mobility shifts the paradigm for the legal and financial consideration within your organization and by regulating bodies. Further, MTS operations should be part of your safety planning training and programming. We will also innumerate and provide a cursory review of the pertinent IETA (NETA) & IEEE standards.

Index Terms – Contingency, Loss of Service, Mobile Substation, Mobile Transformers, MTS, Performance Characteristics, Substation Safety, Voltage Rating, Winding Arrangement

I. INTRODUCTION

Every mobile solution is a highly customized, highly purposed piece of equipment. Operational and/or capital expenditure for a Mobile Transformers & Substations (MTS) is significantly different than any other substation asset. MTS generally deploy and are commissioned in 12-24 hours. However, because a MTS is a contingency asset, there are no hard and fast rules or standards. MTS inherent mobility and customization shifts the paradigm for both acquisition and contingency deployment. Specifying engineers and operators should shift their heuristic analysis and assess and specify for MTS acquisition in terms of three key areas: configuration, capacity, and safety.

Once a requirement for a MTS is identified by gap/contingency analysis one should initially ask how this thing will really be used. Not only voltage rating, but deployment issues must be settled early in the process. Further, perhaps the largest single capital driving factor is capacity. What MVA?

Safety considerations should also begin at the specification level; what should be covered in the specification points? In a loss of service contingency MTS operations must effectively deploy within your organizations safety culture and guidelines. Further, MTS operations should be part of your safety planning, training, and programming.

II. CONFIGURATION

Ratings: Dual Voltage -vs- Dual Units

Of course, the voltage requirements of your substation are where specification begins. The substation's inherent voltage transformation and the specified basic impulse levels (BIL) will drive the selection of every component. "Where competition continues to accelerate in the electric industry, utilities will try to further improve system reliability and quality, while simultaneously being cost effective. High quality, low cost products have become the key to survival." (Advance Design Methodology)

It is possible for a transformer to have dual ratings, "as is popular in spare and mobile transformers. While there is no physical limit to the ratio between the dual ratings, even ratios (e.g., 24.94 × 12.47 kV or 138 × 69 kV) are easier for manufacturers to accommodate." (Sim, Digby) Dual ratings will necessarily increases the size, complexity, and costs radically compared to an equal capacity unit.

Both the primary and the secondary can have dual ratings; and one could even have dual primary and secondary, resulting in a quad rating. The capability of dual or quad is extremely attractive in terms of flexibility, but will building a "Swiss Army Knife" of transformers really be in the interests of your organization?

Even Ratio (Whole Numbers) Applications

Secondary (26.4x13.2 kV, 26.18x13.09 kV, 24.94xI2.47 kV)

"The most common dual-voltage application tends to be a 2-1 ratio on the secondary, which is the simplest ratio to design and manufacture."(Digby) Two identical windings stacked axially will make up the secondary. "It is very important that the two winding sections have an equal number of turns. If there are an unequal number of tums in the two winding sections, circulating currents can be excessive, which can in turn cause excessive heating in the winding. The axial space, or gap, between the two sections must be insulated for the Basic Impulse Insulation Level (BIL) rating of the parallel connection." (Digby) Further, "the spacing between the secondary winding and grounded structures, such as the core and clamping structures, must be insulated for the BIL rating of the series connection."(Digby)

Primary (69x34.5 kV, 138x69 kV, 230x115 kV)

The "typical arrangement for an even ratio dual-voltage primary winding is essentially the same as a secondary application, with the winding being designed with multiple sections." (Digby) However, "primary windings are usually supplied with taps available for de-energized operation (2 positions above nominal and 2 positions below nominal in 2.5% steps for a total range of 10% are standard settings per ANSI standards). In order to maintain an equal number of turns per section for each tap position, each winding section must have taps. This causes the need for additional DETC mechanisms and thus additional cost associated with the mechanism itself as well as additional space required inside to tank." (Digby)

Performance characteristics remain fairly constant for multiple rating systems, but they must be designed and built to diverge to their maximum limits. The resulting max divergent limits necessitate design and build around highest BIL and worst case current scenarios. Insulation makes the windings bigger – big windings increase the diameter of the coil which increases its' distance from the core. The transfer of energy through magnetic flux varies inversely and geometrically with distance: ergo size of the core will have to be increased to develop the necessary flux density to stimulate the now more distant coils. Bigger coils and core means bigger heavier transformer… Bigger means more capital. Bigger and heavier may keep this thing from being mobile.

Consider a HV MTS and a LV MTS, both with split secondary, non-LTC, that when parked side by side and connected in series could deliver the capability you are looking for. Two simple systems could be smaller and cheaper than the "All Things to All People" approach. Further, the separate systems could be acquired in steps or in subsequent years for example. Plus you would have both, and could employ them separately…

Deployment

As basic and simple as the question of ratings is how will this unit be deployed? What type of access is there to deployment locations? Perhaps the most descriptive to your manufacturer: do you have a requirement to drive in or back in. The direction of travel and configuration of your connections will determine the configuration of your MTS.

Begin your process by identifying nodes to identify potential failure points. This usually simply comprises your substation inventory. Once the nodes are identified assess their risks. The space inside a substation yard or being able to turn an MTS around is a normative limiter. Endeavor to identify commonality and create specification points around those common risk nodes.

How mobile? This is the whole ball game. If you need to back in every time – say so. If you need to get it inside your yard every time - say so. If you need to be able to move without a permit – say so.

Questions to ask

- What Voltages – split primary/split secondary?
- Nodes, Risk, Commonality…
- Swiss Army Knife?

Specification Points

- Primary BIL
- Secondary BIL
- Drive In/Back In

III. CAPACITY

Your entire specification will turn on your MVA, I.E. what capacity? Your MVA will be the leading factor in determining the size and cost of your MTS. Normally plan to specify to DOT compliance for non-permitted use of the road. This requires staying within a maximum width, maximum height, and a maximum per axel load. Staying within that very hard box begins with the transformer; all the other desired components are integrated around it. A small transformer allows latitude; a large transformer requires exotic solutions.

MVA (5,12, 15, 20, 25, 50MVA)

It is critical to consider where the MTS will operate. It is entirely acceptable to list States as States set most limits. The most common Department of Transportation (DOT) limit affecting your MTS is the 20,000 pound per axle limit on Federal Interstates. Depending on the ratio of the transformer; higher capacity MTS get so heavy they require an engineered solution to transport them. Custom engineered trailers not only add cost but often reduce flexibility. Further, a non-standard trailer could have an excessive radius of turn; severely limiting which roads it can use.

When specifying a high capacity MTS it is critical to question the necessity of the high capacity configuration. I.E. If you need to specify a 50 MVA unit – Could you specify two 25MVA units that could be deployed separately and paralleled on-site.

How expensive? This is the other shoe waiting to drop. Increasing MVA and requiring custom solutions increases cost. You can have the biggest mobile ever built, but two simple units probably could have the same capability.

Questions to ask

- MVA
- How mobile
- How much

Specification Points

- MVA
- Requirements for mobility
- Turn radius – Or Area of Operation (AOR)

IV. SAFETY

The primary consideration for MTS design is safety. Likewise, safety and the inclusion of your safety program in specification of your MTS should be a primary consideration.

"There are numerous laws, rules, codes, etc. governing safety requirements; of them the most important being IEEE Standard C2-2012. National Electrical Safety Code® (NESC®). The main mission of all these regulations is safeguarding of personnel from hazards arising from the installation, maintenance or operation of substation equipment." (Csanyi)

MTS safety should be the same as any other substation at a minimum; but further consideration must be given to the mobility. The Census of Fatal Occupational Injuries (CFOI) 0277, TABLE A-1. Fatal occupational injuries by industry and event or exposure, all United States, 2013 indicates fully 42% of fatalities in the utility industry were transportation incidents.

MTS safety should not ignore the basics of Personal Protective Equipment (PPE). Gloves, Boots, and Helmets should be worn at all times. Specification should require operability while wearing PPE.

Clearance – Specify clearance from energized components to prevent inadvertent or incidental contact. Live components should be guarded or enclosed. This is not a requirement, but should be considered.

Illumination – "There should be sufficient illumination for personnel to clearly see their surroundings and perform any work safely. Required illumination levels are specified in NESC®." (Csanyi)
Stairs – Specify stairs and what kind. Specify a non-skid deck if required.

Grounding – Grounding, Grounding, and Grounding.

An MTS "should be connected to a station ground grid which should be designed to ensure that step and touch potential values are lower than the ones stipulated in the applicable standards." (Csanyi) The grounding technique should be part of your specification. If you intend to connect to a ground network in place – specify that. If you need to have complete components to install and develop a ground network at a bare location – specify that. Further, specify a grounding bar the length of the system to facilitate personal grounds.

Questions to ask

- Have safety personnel had input into specification?
- Have operations personnel had input into specification?
- How will MTS be grounded

Specification Points

- Clearances
- Illumination
- Ground – Equipment on board

V. CONCLUSIONS

MTS generally deploy and are commissioned in 12-24 hours. Every mobile solution is a highly customized, highly purposed piece of equipment. Operational and/or capital expenditure for a Mobile Transformers & Substations (MTS) is significantly different than any other substation asset.

MTS specifications should reflect they are emergency equipment for contingency operations. However, as Mark Moss (32 year Duke Energy) states, “you may find your mobile deployed for a week and sitting there on a line rebuild 2 years later.” Because a MTS is a contingency asset, there are no hard and fast rules or standards. Specifying engineers and operators should shift their heuristic analysis and assess and specify for MTS acquisition in terms of three key areas: Configuration, Capacity, and Safety.

CONFIGURATION

- Primary BIL
- Secondary BIL
- Drive In - Back In

CAPACITY

- MVA
- Mobility
- AOR

SAFETY

- Clearances
- Illumination
- Grounding

Early in the planning stages give consideration to configuration options, and capacity based on operational needs, flexibility, and capital costs. Specify configuration and capacity points clearly, and in terms of actual operational needs. Include integral safety considerations at the specification level and make MTS operations part of your safety planning, training, and programming.

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VII. BIOGRAPHY

Jeffrey Wimmer received his Bachelor of Science in Engineering from the United States Air Force Academy. He holds a Master of Aeronautical Science and a Masters in Management. He is currently a Regional Account Manager for Gilbert Electrical Systems; Elgin Equipment Group. Formerly he was the Vice President for Sales and Marketing; North America for SGB USA, Inc., the Business Development Manager for Equisales Associates Inc. of Houston Texas; and the Business Development Manager North America for ABB Dry & Cast Technologies. Jeffrey is a native of Roanoke, VA; and grew up on the family farm in the Blue Ridge Mountains. Subsequent to receiving his commission he completed flight training and served as an aviator and special operator. Jeffrey earned the Senior Navigator Badge, Free-Fall Parachutist Badge, Air Assault Badge and the coveted Pathfinder Badge. He has served as Policy Analyst & Chief of Staff at the Oregon Legislative Assembly, and has served as a contributing member of numerous public policy think-tanks. Jeffrey is a Certified Substation Maintenance technician, and is also a certified Mediator. Jeffrey is an active, publishing member of the IEEE Power & Energy Society & the Industry Application Society and a past Chair of the Virginia Mountain Section. Jeffrey is the proud father of Kaitlyn Rose Wimmer, Lauren Elizabeth Wimmer, and Joel Zanoria Wimmer.

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Near Time As Built Surveys

A Quality Assurance Plan During Transmission Line Construction

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1.0 Abstract

Near Time As Built surveys are a simple shift in the timing and approach that can reduce the risk associated with the schedule and budget, while providing an independent Quality Assurance during the construction of an electric transmission line.

Rather than performing the As Built Survey at the end of the construction phase, the surveys are performed incrementally, within days of completing segments, with each construction phase confirmed and documented. The advantages of Near Time As Built surveys provide significant business and technical benefits. First, the incremental delivery shortens the overall schedule because the activity is running concurrently with construction. Secondly, the datasets can be delivered within days of finished construction on segments, which allows for corrective action to occur quickly if site conditions or construction factors impose modification to the original design. Critical clearance measurements can be delivered within minutes of clamping in a conductor. The survey serves as Quality Assurance (QA), saving time and money for the owner and construction company. Moving the activity forward in the project timeline reduces the risk of compromising the planned energize date. The As Built survey will also meet the on-going maintenance to preclude the reoccurrence of similar issues that caused the 2010 NERC Facility Rating Alert initiative. While the obligation for entities to report to NERC has concluded, many entities continue remediation, and some have put maintenance practices in place to help preclude the recurrence of similar issues and minimize the reliability risk posed to the Bulk Power System. Finally, the acquired datasets enhance construction inspection and can be repurposed for maintenance operations for asset management / GIS databases once the transmission line is placed in service.

Figure 1 – Ground Surveys for Electric Transmission Line

2.0 Introduction

The term "Near Time As Built Survey" was coined by SAM to introduce one of the Best Management Practices (BMPs) we have employed during the construction of an electric transmission line. The practice, along with others are a series of procedures and quality assurance strategies that have been established from past experience for avoiding, reducing, or minimizing negative impacts during the survey and construction of projects. The BMPs involve the planning, execution, control, mitigation, and practice of activities involved in the construction, with consideration given to the future maintenance and operation of an electric transmission line.

3.0 What is Near Time As Built?

Near Time As Built surveys are a simple shift in the timing and approach that can reduce the risk associated with the schedule and budget, while providing an independent Quality Assurance during the construction of an electric transmission line. The conductor variables that have an effect on the accuracy of the designed system include: total elapsed time between construction and energizing, exposure to temperature extremes, wind and ice load that may occur during the construction period. The more time that has elapsed between construction and As Built documentation can result in increased cost, risk, and schedule delay if the line is not built as designed. The surveys are performed incrementally, within days of completing segments, with each construction phase confirmed and documented.

4.0 Benefits

The benefits of a Near Time As Built survey provide significant business and technical advantages. First, the incremental delivery shortens the overall schedule because the activity is running concurrently with construction. Secondly, the datasets can be delivered within days of finished construction on segments, which allows for corrective action to occur quickly if site conditions or construction factors impose modification to the original design. Critical clearance measurements can be delivered within minutes to the design engineer of clamping in a conductor using motion tablets that are Wi-Fi enabled.

The As Built survey will also meet the on-going maintenance to preclude the reoccurrence of similar issues that caused the 2010 NERC Facility Rating Alert initiative. While the obligation for entities to report to NERC has concluded, many entities continue remediation, and some have put maintenance practices in place to help preclude the recurrence of similar issues and minimize the reliability risk posed to the Bulk Power System. Finally, the acquired datasets enhance construction inspection and can be repurposed for maintenance operations for asset management / GIS databases once the line placed in service.

5.0 Project Example

The Near Time As Built Survey can utilize traditional Total Station, GPS instruments or Terrestrial Scanners, Image Sensors for close-range photogrammetry for supplemental measurements, 360-degree HD videos and an Infrared Thermal Sensor to obtain direct conductor temperature.

SAM provided Near Time As-Built Surveys for Ameren Illinois in September 2013 for the Hutsonville-Neoga Rebuild, located in Crawford, Clark, Cumberland and Shelby Counties in Illinois. The project consisted of 45 miles of an existing transmission line, for a 100-foot right-of-way. Sag verification was surveyed during the conductor stringing construction phase. The field crews acquired the conductor measurements in conjunction with the weather data and transmitted the data via cellular Wi-Fi connection to the Dallas office for Quality Control. The As-Built measurements were compared to the designed wire sag, with the results communicated to the contractor within a 5-10 minute window back to the contractor. Figure 2 details the information obtained during the survey.

Span	Survey Date	Survey Time	SAM Temp (°F)	Contractor Temp (°F)	Degree Used	Wind Direction	Wind Speed	Cloudy or Sunny	Deisgn Wire Sag	As built Wire Sag	Difference
6-7A	9/23/2013	9:20	68.9	64	65	SE	0.6	Sunny	5.790	6.039	-0.249
6-7B	9/23/2013	9:20	68.9	64	65	SE	0.6	Sunny	5.790	6.018	-0.228
6-7C	9/23/2013	9:20	68.9	64	65	SE	0.6	Sunny	5.790	5.953	-0.163
15-16A	9/23/2013	11:30	79	73	75	SE	2.8	Sunny	6.790	7.228	-0.438
15-16B	9/23/2013	11:30	79	73	75	SE	2.8	Sunny	6.790	7.150	-0.360
15-16C	9/23/2013	11:30	79	73	75	SE	2.8	Sunny	6.790	7.144	-0.354
24-25A	9/23/2013	4:30	78.7	76	75	SE	4.6	Sunny	5.680	5.655	0.025
24-25B	9/23/2013	4:30	78.7	76	75	SE	4.6	Sunny	5.680	5.544	0.136
24-25C	9/23/2013	4:30	78.7	76	75	SE	4.6	Sunny	5.680	5.473	0.207
33-34A	9/23/2013	6:00	77.6	75	75	SE	1.4	Sunny	6.740	6.309	0.431
33-34B	9/23/2013	6:00	77.6	75	75	SE	1.4	Sunny	6.740	6.233	0.507
33-34C	9/23/2013	6:00	77.6	75	75	SE	1.4	Sunny	6.740	6.162	0.578
261-262A	9/24/2013	11:30	73	75	75	SE	6.2	Sunny	6.800	6.958	-0.158
261-262B	9/24/2013	11:30	73	75	75	SE	6.2	Sunny	6.800	6.960	-0.160
261-262C	9/24/2013	11:30	73	75	75	SE	6.2	Sunny	6.800	6.854	-0.054
253-254A	9/24/2013	3:00	85	85	85	SE	5.7	Partly Cloudy	6.070	6.255	-0.185
253-254B	9/24/2013	3:00	85	85	85	SE	5.7	Partly Cloudy	6.070	6.202	-0.132
253-254C	9/24/2013	3:00	85	85	85	SE	5.7	Partly Cloudy	6.070	6.085	-0.015
272-273A	9/24/2013	5:20	85	85	85	SE	6.5	Partly Cloudy	6.430	6.540	-0.110
272-273B	9/24/2013	5:20	85	85	85	SE	6.5	Partly Cloudy	6.430	6.595	-0.165
272-273C	9/24/2013	5:20	85	85	85	SE	6.5	Partly Cloudy	6.430	6.374	0.056

Figure 2 - Survey data acquired

During this project, the metrological information was obtained using conventional weather instrumentation. However, at close range and with hand-held thermal sensors, direct conductor temperature can be acquired. Thermal images can be obtained along with high resolution ground obliques to enhance construction inspection and operation and maintenance activities.

6.0 Lessons Learned

One important lesson that was learned is that it is possible to work too closely behind the construction process. Coordinating with contractors for exact site location planned for work, timing and reporting the results may have slowed down the contractor. However, if we allowed the contractor to work ahead 2-3 miles, the QA process was least disruptive, yet still allowed for corrective action to be taken quickly, if required. Keeping a good line of communication up front with the contractor is important. Effective communication between the office and field so that the office was available to check the data after normal work hours and on weekends was crucial.

7.0 Multi-Purpose Delivery Items

The critical height measurements are surveyed with images superimposed to provide visual confirmation of the direct measurement point. If required, the imagery can also be utilized for indirect photogrammetric measurements performed in the office to supplement field survey measurements.

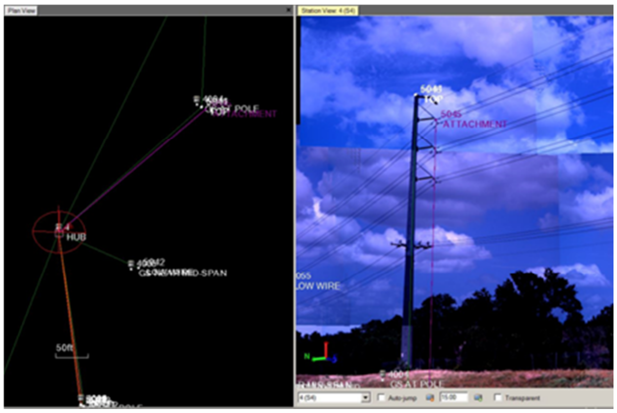

Figure 3 - Survey measurements with co-registered imagery

For a comprehensive drive down, a 360 degree HD video can be collected to document construction progress and allow engineers to visit the site in a virtual office environment.

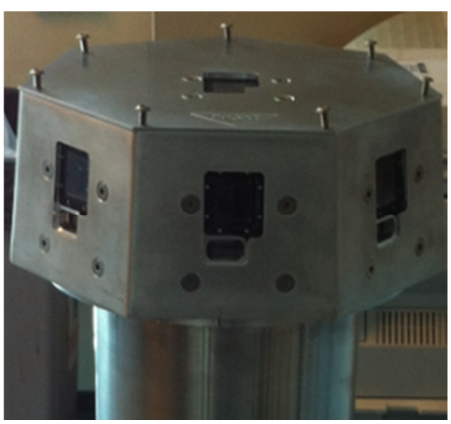

Figure 4 - 360 degree HD video / camera array

High resolution still photos supplement the HD video for detailed inspection evidence. The images and video are geo-referenced and indexed to the structure.

Figure 5 - High resolution imagery

8.0 Relative Cost Comparison

The survey serves as a Quality Assurance (QA), saving time and money for the owner and construction company. Figure 6 shows the relative cost per mile for an As-Built survey using aerial LiDAR methods vs. Near Time Ground survey methods. The per mile cost intersects and is equal at ~15 miles. Therefore, the ground surveys are financially beneficial for lines 15 miles or less in length, with the cost for an aerial survey dropping significantly for longer lines. However, the Near Time As Built ground surveys provide early detection of issues, they don't compromise the planned energized date and offer a host of value added benefits delivery products that can be repurposed for operations and maintenance activities.

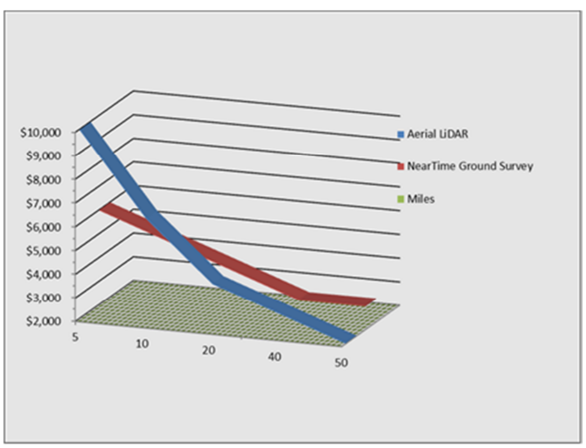

Figure 6. Relative Cost for Ground Survey vs Aerial Survey or As-Built

9.0 Summary

Near Time As Built surveys reduce the risk associated with the schedule and budget, while providing an independent Quality Assurance during the construction of an electric transmission line. The incremental approach that runs concurrently with constructions provides the following advantages:

- Compresses the overall schedule because the activity is running concurrently with construction.
- Allows for corrective action to occur quickly.
- Reduces the risk of compromising the planned energize date.
- Provides on-going maintenance strategy for the 2010 NERC Facility Rating Alert initiative.
- Enhanced datasets aid construction inspection.
- Datasets can be repurposed for maintenance operations for asset management / GIS databases.

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NERC CIP-014: Physical Security – Regulatory Compliance and Real World Implementation

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INTRODUCTION TO CIP-014

NERC's CIP-014, Physical Security, is a newly developed critical infrastructure protection standard, provided in response to a FERC directive and approved by FERC with a US enforcement date of October 1, 2015. The standard requires electric transmission system owners to 1) identify key substations and control centers that could pose a system instability risk if they were physically attacked, 2) identify potential threats and vulnerabilities for those substations, 3) develop and implement a security plan to protect those substations from physical attack, and 4) obtain third-party verification of the conclusions and security plans.

REASONS FOR THE STANDARD

Any discussion of critical infrastructure certainly includes the electric grid; the bulk electric system (BES) must be both resilient and reliable. There have been a number of recent CIP standards focusing on cyber security, but the need to address physical security to protect our critical infrastructure has also become apparent.

Substation physical security became a topic of national discussion when the Metcalf Substation outside San Jose, California was physically attacked on April 16, 2013. An apparent sniper attack during the night from a nearby hillside resulted in the loss of seventeen transformers and additional damage to the station's high voltage equipment. Due to the resiliency of the regional grid and operator adjustments, this extensive damage did not result in a blackout, or even the loss of electric service to a single customer. However, the incident received widespread attention from the national media, including repeated coverage by the Wall Street Journal.

CIP-014-1 was developed and published quickly, to address this newly perceived vulnerability to physical security at BES facilities. The stated purpose, as written in the standard, is "to identify and protect transmission stations and transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or cascading within an interconnection" (NERC, 2014). A new iteration of the ruling, CIP-014-2 with a future enforcement date of October 2, 2015, will replace CIP-014-1. The only difference is deleting the poorly-defined term "widespread" from the phrase "widespread instability" in the standard.

Note that CIP-014 does not supersede or invalidate work by IEEE. The IEEE Committee on Physical Security has begun updating Standard P1402 – Guide for Physical Security of Electric Power Substations. While the document summary does state "…overt attacks against the substation for the purpose of destroying its ability to operate, such as explosives, projectiles, vehicles, etc, are beyond the scope of this guide," the updated guide will address "positive access control, monitoring of facilities, and delay/deter features" and will be "updated to reflect the latest changes in physical protection technologies and procedures" (IEEE, 2015).

The CIP-014 standard includes six requirements, denoted as steps R1 through R6. Requirement R1 is a risk assessment in order to identify which particular facilities (substations and their associated control centers), if damaged or rendered inoperable, have the potential to create instability, uncontrolled separation, or cascading within an interconnection. R2 is a third-party verification of that assessment. R3 requires notification to owners and operators of any identified control centers. Once the critical substations have been identified, an evaluation of potential threats and vulnerabilities must be completed as requirement R4. Next, in step R5, security plans must be developed and implemented to mitigate or defeat the identified threats. Step R6 is a third-party independent review of the security plan. The requirements are summarized below; refer to the NERC Standard for additional details and the complete requirements.

SUMMARY OF CIP-014 REQUIREMENTS

R1 – Risk Assessment

The first step is to identify critical facilities according to the criteria set forth in CIP-014-1, which is based on the screening and ranking procedure set forth in Section 2.5 of Attachment 1 of CIP-002-5.1, Cyber Security – BES Cyber System Categorization. The ranking table, common to both standards, is shown below (NERC, 2015):

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

CIP-014-01 is applicable to transmission facilities operating at 500 kV or higher. For stations operating between 200 kV and 499 kV, the standard is applicable if the station has an aggregate weighted value over 3000 for the sum of incoming and outgoing BES lines. The Step R1 risk assessment must be completed for stations meeting the applicability criteria.

The CIP-014 risk assessment process will require analysis of the factors and criteria considered in the initial screening of critical facilities. Transmission line voltage, capacity, operation, and location on the grid as tie lines and generator outlet lines must be considered to verify the initial screening and to confirm that identification of critical facilities is accurate. Power system analysis of the system response may determine additional facilities that could be critical to the security of the interconnected systems based on the resulting criteria violations found in the case work. Generating unit instability and loss of large blocks of load is unacceptable in some instances.

Assumptions in the powerflow and transient stability models and data should be validated to ensure that the system will be accurately represented under a variety of credible simulated operational scenarios. For example, an extreme disturbance would be simulated as the loss of all lines terminating in the critical facility. NERC TPL standard criteria should be used as a base line for measuring system response for the powerflow and transient simulations that will be required for the R1 assessment. Other local or regional criteria for first swing voltage dips and overload rating of facilities should also be included.

Note that CIP-014 does NOT dictate methodology and does NOT dictate specific criteria for acceptable system response. This is left up to the region and the transmission owner. The region and its members should agree on the study methodology and criteria that will specify the clearing times, voltage recovery criteria and damping criteria to be used in the assessment studies. During simulations, generator instability (total MW tripped due to loss of synchronism as well as low-voltage recovery ride through capability of generators) must be monitored as well as low voltage recovery and resultant load lost due to wide spread low voltage at buses. Selected channel output quantities should be tracked throughout the stability studies as a measure of system performance.

For example, generators that experience very low voltage that do not meet the agreed upon study criteria will be tripped off line during a fault. For load flow studies, if the base case does not converge, an investigation of the amount of reactive support needed, or the amount of real power load that would need to be tripped to allow the base case to solve, should be performed.

If dynamic simulation cases do not converge for a particular event, an investigation of the non-convergence must be performed so that the event may be accurately classified as either a true instability event or a numerical computation issue in the model.

R2 –Third Party Verification

An independent review must be conducted by an experienced power system planner with knowledge of modeling and power system analysis techniques in order to validate the model assumptions and case study procedures. In general, a selected set of powerflow and transient stability cases will be closely reviewed to verify the accurate representation of the transmission system and its response to an accepted set of generator and transmission line contingencies. The results of this set of steady state contingencies and transient disturbances would be reviewed to ensure all local and NERC reliability requirements can be met.

Collaboration and interaction with the engineers performing the R1 Assessment is encouraged in the standard. Feedback should be provided by the reviewer to make corrections and suggestions as the analysis progresses. This would usually be provided in written form to provide clear documentation of the independent review of results by the third party. NERC is presently developing a Reliability Standard Audit Worksheet (RSAW) to be filed as documentation of compliance.

R3 – Notification

The third requirement of CIP-014-01 is notification to the transmission operator of any primary control centers associated with transmission stations identified in step R1 and verified in step R2.

R4 – Threats and Vulnerabilities Analysis

Requirement R4 is to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to the transmission stations, substations, and primary control centers identified in R1 and verified in R2. This assessment must include unique characteristics of the station, past history, and any intelligence or threat warnings from agencies.

There are a number of different risk assessment methodologies. Sandia Labs has developed RAMs for critical infrastructure, chemical facilities, dams, water utilities, etc. Basic questions are the same:

- What are the threats?
- What is the effectiveness of the security system?
- Is the risk acceptable, and what will we do if not?

Note that the determination of threats and design basis threats, as well as the assessment of key vulnerabilities, is extremely site-specific. Critical facilities are widely variable in physical size, surroundings, equipment, and arrangement – from gas-insulated substations located in inner city buildings, to fenced in substations covering many acres in isolated, rural areas, miles from a town. Each site will have unique challenges, unique threats and vulnerabilities.

An assessment team including utility operations staff, engineers, and security professionals will be needed to provide a comprehensive analysis. Security professionals need previous experience in threat and vulnerabilities analyses and risk assessment methodologies, and they will utilize both security industry information and local knowledge to aid in the assessment. Specifics of the critical equipment, operational needs and redundancy, and availability of spare parts would be best known by the facility owner and operator.

It is likely that the design basis threats will include:

1. Vehicular intrusion and vehicular-borne explosives
2. Unauthorized personnel entry and backpack IED’s (improvised explosive devices)
3. Ballistic threats, such as long range firearms.

Media reports have included mention of additional types of threats to our electric grid – from airplanes and drones to electro-magnetic pulse and RPGs. But these threats are not likely to be determined to be design basis threats.

R5 – Security Plan

The fifth requirement of CIP-014 is development and implementation of documented physical security plans that cover the identified facilities. CIP-014 states “the physical security plan(s) shall include…

- Resiliency or security measures designed to collectively deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4…” (NERC, 2015)

The physical security plan must also include, law enforcement contact and coordination, a timeline for implementation, and provisions to evaluate evolving threats.

R6 – Third Party Review

An unaffiliated third party must review the threat assessments and physical security plans of R4 and R5. This review can be performed concurrently with the R4 evaluation and R5 security plan development activities.

The third party reviewer must have electric industry physical security experience and at least one Certified Protection Professional (CPP) or Physical Security Professional (PSP) on staff, or be approved by the Electric Reliability Organization (ERO), or be a governmental agency with physical security expertise, or have demonstrated law enforcement, government or military physical security expertise.

Confidentiality of information is critical to both the R6 third party review and the R2 review. Sensitive information must be available to the reviewers, but also must be protected through appropriate document control, cyber security measures and the use of non-disclosure agreements.

OVERALL SECURITY MEASURES AND COORDINATION

Physical attacks can be deterred or delayed through physical barriers that impede entry, limit the approach of attackers, or impede the line of sight to potential targets. But it must be emphasized that barriers are just one component of an overall security plan. Additional security measures to be considered for inclusion as part of the overall security plan range from low cost and low tech vegetation clearing to cutting-edge gunshot detection systems. There are programs coordinated by NERC, FBI, DHS, DOE, FERC, regional entities and utilities to share findings and recommendations and best practices for security. Additional security measures to be considered may include:

- Video surveillance
- Security officers
- Security awareness training
- Local law enforcement coordination
- Infrared cameras
- Virtual perimeters
- Card readers
- Automated gates
- Vegetation clearing
- Thermal imaging
- Night vision
- Long range gun shot detection
- Enhanced lighting
- Equipment shielding and hardening
- Additional spare equipment
- Spare equipment relocation
- Protection of confidential information

The need for a coordinated approach to critical facility security cannot be overemphasized; consideration of environmental factors, permitting, public involvement, and input from stakeholders is necessary. Planning must include integration of physical security with cyber security and operational procedures for coordinated communication and response.

In terms of physical security, the most likely items to receive the greatest attention in implementation of CIP-014 are:

- Substation access and entry
- Transformers
- Control houses

SUBSTATION ACCESS AND ENTRY

Well-designed substation perimeter barrier systems can serve to address multiple design basis threats. Recall that the most likely design basis threats will include vehicular intrusion and vehicular-borne explosives, unauthorized personnel entry and backpack IED's, and ballistic threats, such as long-range firearms.

Most existing substations have chain-link fencing with three-strand barbed wire topping. This fencing type does provide a level of protection against unauthorized entry, but does not provide vehicular intrusion protection or line of sight obstruction for ballistic threats. Replacement of this common chain-link perimeter fencing with a high, non-climbable, opaque wall would provide multiple benefits, including obstructing line of sight. Installation of screening fabric or vinyl slats is a low cost improvement to obstruct line of sight if the existing fencing is capable of the additional wind load. The security plan will most likely include more substantial improvements.

Substation walls and secure, controlled access gates that have crash resistance, ballistic and blast ratings provide a nearly a complete solution to substation physical security. The selection and design of ballistic-rated substation barrier walls should be based on standard criteria such as the Underwriters Laboratory 752 standard (UL, 2013). Concrete (cast-in-place and precast), masonry, steel, and composite wall types can all be designed to provide ballistic and blast protection. A number of proprietary barrier wall systems are available, with UL752 test results provided by manufacturers. Assistance from the DHS Interagency Security Committee is also available to assist in ballistic and blast resistant barrier design (DHS, 2015).

The importance of site-specific assessment and evaluation by security professionals, working in conjunction with the transmission owner and engineering team, cannot be overemphasized. At some facilities, for instance, natural features such as trees would be a positive asset around the substation perimeter, while at other facilities the opposite would be the case.

Intrusion of vehicles into a substation is not significantly deterred by the typical chain-link fence and gate. An explosive-laden vehicle could quickly gain entrance into a facility and gain the proximity to critical equipment required to cause extensive blast damage. Significant gains in damage resistance can be achieved through maintaining reasonable stand-off distances to critical equipment through vehicle-resistant site perimeter treatment (ASCE, 2015). Options for vehicular barriers include precast concrete blocks or concrete walls surrounding the perimeter fencing, reinforcing existing fencing through installation of guard rails, and the installation of ditches and berms. The Department of Defense has tested ditch/berm designs for vehicular intrusion, and provides guidance on vehicular barrier design and selection in UFC 4-022-02 (DoD, 2009). Additional information is also available through the USACE, Department of State, FEMA, and other agencies.

Installation of a separate, secure, vehicular access gate on the approach drive may also be a physical security plan recommendation. There are numerous proprietary crash-rated vehicular gate systems, including drop-arm gates, swing gates, and other systems, operated manually, by key card, or other options. Consideration should be given to a sally port type installation, with two gates to provide additional security.

Unauthorized personnel entry can be deterred through many of the same perimeter barrier recommendations above, with the addition of turnstile type gates and key card entry, as well as climb-resistant wall types.

An alternate to replacement of perimeter fencing is obstruction of line-of-sight to critical equipment and shielding critical equipment with installation of ballistic-resistant shielding walls around particular components. This equipment, identified through the vulnerability analysis, would most likely include certain components of transformers, control panels, and the control building.

TRANSFORMERS

Transformers are critical elements of BES substations, as they're generally the most vulnerable and costly assets in a facility. Transformers, especially very high voltage transformers, are difficult to remove and replace. There is high global demand and a lengthy delivery time of approximately eight to eighteen months for engineering, manufacturing and testing. The location and protection of transformers, including redundancy through spares or transformer sharing programs, and detailed planning for expedited repair or replacement are necessary components of a facility security plan. (Bentley, K. and Boucher, J., 2014).

Due to the criticality of transformers, programs have been developed on both national and regional levels to provide spare transformers and replacement parts when needed on an emergency basis. As examples, the Edison Electric Institute (EEI) has a spare transformer equipment program (STEP), and NERC has a spare equipment database (SED).

Design of replacement transformers and transformers for new installations in the BES should consider hardening of this critical equipment for increased physical security. Transformer manufacturers offer dry type bushings, design alternatives for less volatile cooling oil, alternate radiator locations, hardened control panels, and other optional features.

The physical security of existing transformers can be improved through the use of shield walls to provide obstruction to the line of sight and specific ballistic or blast resistance. This type of equipment-specific shield wall can have a reduced cost as compared to perimeter wall installation. There are multiple vendors offering proprietary wall products of materials including precast concrete, steel plate, reinforced fiberglass, and ceramic. Important considerations in the layout and design of these walls is maintenance of proper air flow around equipment and the potential need for removal of wall sections for equipment maintenance or replacement.

CONTROL HOUSES

Many older substations have control buildings with windows and standard exterior doors. Physical security upgrades should include removal of windows, hardened steel doors, and high security locks and access systems to preclude unauthorized entry. In some cases, installation of shield walls or ballistic-rated coverings/panels in some areas may be recommended.

Control house replacements should include physical security considerations in determination of control house location, construction type, and access.

CONCLUSION

CIP-014 was developed in response to increased awareness of the importance of resiliency of the bulk electric system and the possibility of physical attack to substations. The purpose of the standard is "to identify and protect transmission stations and transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or cascading within an interconnection." The standard outlines a systematic approach, including six specific requirements, but including flexibility in assessment methodologies and design of physical security measures at identified stations.

The CIP-014 rule will certainly lead to modifications of some existing substations. The coordinated efforts of knowledgeable systems planning engineers, substation and civil engineers, and security professionals are required to determine the most appropriate physical security design solutions. In this manner, transmission owners can comply with the new rule, but more importantly, protect the country's most critical infrastructure – the electric grid.

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Permanent Solutions for Temporary Loads:
An Alternate Approach to Electric System Design for Short-Term and Mobile Industrial Loading

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Abstract

Open-air substations are a widespread design with electric utility personnel familiar with and trained in the safe operation of these substations. While open-air substations are also generally considered to be the most economical method to serve industrial size loads, they require a relatively large amount of land, are designed with a 40 year service life, and are only economical with finite lengths of distribution lines. These traits are not conducive to the requirements of the short-term and mobile loads associated with industrial oil and gas production. The use of open-air substations with this type of short-term load can leave the utility with a large investment in equipment that cannot be easily relocated when the short-term load is no longer needed. This paper explores an alternate approach to open-air substations to serve these large but temporary loads.

Introduction

An oil and gas company tasked ESC engineering with designing an electric system that would support their infrastructure for a large production field located in northeastern Colorado. The field covers over 100 square miles (100 sections), with up to four well pads per section and up to 32 wells per pad. The field's electric loads are served by a double circuit 115kV transmission line. Two sub-transmission voltages, 34.5kV and 69kV, come out of two separate substations due to the field being located in the territories of two different electric cooperatives. A loading study determined that at full build out each section would require up to 7MVA of transformer capacity. This posed a unique challenge for the two electrical utilities.

Utilizing the standard open-air substation design that both utilities employed, one substation would need to be built for every few sections of field that was developed. If every section that was developed by the oil and gas company was a long term load, then this approach would be acceptable. However, due to the nature of oil and gas explorations, these loads would be temporary, lasting several years at most. If open-air substations were constructed, each utility would be required to make large investments in equipment that would become spare after a short in-service duration. While spare equipment could be relocated to new installations, it is likely that new installations would need to be in service before existing installations could be decommissioned. This would generate large quantities of inventory that had only been used once. Another design approach was needed to serve these large but temporary industrial loads.

Existing Portable Transformers

To serve the industrial loads of the client, a mobile substation design was required. While mobile transformer designs are already utilized by electric utilities, a mobile transformer was not ideal for this application (Figures 1 and 2). Mobile transformers require special training to set up and operate, require yearly roadway registration, and require maintenance of the flatbed trailers in addition to the substation equipment. While this might not be a major consideration for installations of less than one year, it can become a major consideration for longer installations. It was anticipated that some of the sections under development by the oil and gas company could be in operation for several years, which posed the potential for the flatbed trailers to develop mechanical problems, such as flat tires, and yearly trailer registration payments for equipment that had not been transported over the road.

An alternate to the mobile transformer utilized by utilities was a skid mounted transformer, which is normally utilized in the mining industry (Figure 3). A skid mounted transformer, as the name implies, is mounted onto a skid instead of a flatbed trailer. This skid does not have the maintenance issues that a flatbed trailer would have, such as flat tires, nor does it require roadway registration. The skid mounted transformer has the added benefit that any large piece of mobile haulage equipment, such as a bulldozer (Figure 4), can drag the transformer into place. However, as can be seen in Figure 3, the skid mounted transformer is not designed with NESC clearances in mind, and still requires special training to properly operate the equipment. This tight configuration makes troubleshooting problems difficult and does not allow for the safe operating procedures taught for open-air substations. Another design needed to be created that incorporated the advantages of a skid mounted transformer with the ease of operation of an open-air substation.

Skid Mounted Substation

To minimize equipment-specific training and to allow both utilities to maintain their safe operating procedures, a design was required that would mimic an open-air substation. A design investigation was started to determine if an open-air substation could be installed on a skid; thus maintaining standard operating procedures for both utilities while gaining the benefits and flexibility of skid mounted equipment.

Before a physical design could be attempted, a substation one-line needed to be created (Figure 5). As was mentioned previously, each section would require up to 7MVA of transformer capacity. If all 7MVA of transformer capacity was required, then the full load current at 69kV would be 58.6A and at 34.5kV would be 117A. At this level of full load current, both utilities agreed that high-side fuses would provide sufficient transformer protection. It was also agreed that a high-side group operated switch should be installed to provide a means to easily isolate the fuses in the event of needing to replace the fuses.

On the distribution portion of the installation, the voltage was 12.47kV, resulting in a full load current of 324A. This full load current was within the operating range of a Cooper Nova recloser, which both utilities already used on their systems. Due to the nature of industrial loads, it was also determined that a regulator bank would be required.

With the one-line diagram created, the next task was to determine the limiting factors for a skid mounted substation. It was determined that the largest electrical clearance required was for a group operated vertical break switch. From the NESC clearance tables for open-air substations and air break switches, this clearance is 5’-0” between phases, or 10’-0” from centerline of the outside phases for a 69kV rated switch. Upon contacting shipping companies, it was determined that standard shipping widths are 14 feet, with the maximum width of an oversized load being 16 feet. When designing the steel support structure for the 69kV group switch, it was determined that the maximum width of the skid would be approximately 14 feet. This kept the skid within the maximum shipping dimensions allowed over interstate highways. However, the height of a skid mounted substation posed difficulties.

To achieve an open-air substation style design on a skid; a high-side, deadend, H-frame structure was required. As shown in Figure 6, an H-frame structure with all of the required equipment would be approximately 27 feet above the skid base. This would limit the ability to transport the substation. To reduce the height during transportation, all of the steel structures were designed with hinges. This allowed the skids to be collapsed to a height of approximately 13 feet during initial shipping or transport to the next site (Figures 7 to 10). The last technical hurdle was reducing the length of the skid.

As is also depicted in Figure 6, it was decided to utilize two skids for each substation. This would reduce the length of each skid to approximately 28 feet, allowing for easier transport and installation. The first skid would incorporate the high-side H-frame, switches, fuses, surge arrestors, power transformer, and metering PT’s. The second skid would be comprised of the voltage regulators, bypass switches, recloser, and a control enclosure for the utilities’ SCADA equipment. With a design approach in place, the next task was determining how to best install the sub-transmission lines and distribution system to integrate with the skid mounted substations.

Sub-Transmission and Distribution System Design

The production field is located within the service territory of two separate rural electric distribution cooperatives. The boundary between the cooperatives essentially splits the field into a northern and southern half. The distribution cooperatives are both served by the same generation and transmission cooperative (G&T). The G&T built a double circuit 115kV transmission line as the bulk power supply for the production field and the associated processing facilities. The northern distribution cooperative has a standard sub-transmission voltage of 34.5kV while the southern distribution cooperatives' is 69kV. The G&T constructed two substations, a 115/34.5kV and a 115/69kV, to serve the distribution cooperatives' sub-transmission systems. A 34.5kV and a 69kV switchyard were constructed adjacent to the G&T's substations to serve the sub-transmission circuits. Figure 11 depicts a simplified version of the electric system.

The sub-transmission/distribution systems for both distribution cooperatives had the following similar characteristics:

- Tangent Structures
  - Single Pole Wood
  - Sub-transmission on horizontal post insulators
  - Three-phase 12.5kV distribution underbuild on crossarms
- Deadends and Running Angles
  - Single pole guyed wood with some self-supporting steel poles on concrete foundations at locations lacking guying room
  - Three-phase 12.5kV distribution underbuild using buckarm construction
- Typical span length of 250 to 300 feet
- Disconnect switches installed on the 12.5kV underbuild every mile at the sections lines for sectionalizing

The northern distribution cooperative's sub-transmission system consisted of 34.5kV with a three-phase 12.5kV distribution underbuild. T2-4/0 ACSR conductor was used for both 34.5kV and 12.5kV. The initial build out of the system consisted of four 34.5kV circuits and 14 circuit miles of line. A 40 foot wide Right-of-Way (ROW) was acquired for the sub-transmission system. Eight skid substation sites were selected along the alignment. Skid substations were installed at three of these locations.

The southern distribution cooperative's sub-transmission system consisted of 69kV with a three-phase 12.5kV distribution underbuild. A 477 ACSR (Pelican) conductor was used for both 69kV and 12.5kV. The initial build out of the system consisted of two 69kV circuits and 16 circuit miles of line. An 80 foot wide Right-of-Way (ROW) was acquired for the sub-transmission system. Ten skid substation sites were selected along the alignment. Skid substations were installed at three of these locations.

The siting of the sub-transmission lines within the active production field presented numerous challenges. In general, the alignment paralleled oil, gas and water pipeline ROW's. The location of all poles and anchors were staked during the preliminary design phase to ensure that there were no conflicts with existing and planned infrastructure. The production field is co-located with a United States Air Force Missile Squadron's alert and launch facilities. Underground fiber-optic lines for the Air Force crisscross the production field. No structures were allowed within 100 feet of Air Force fiber-optic lines. The location of these fiber-optic lines is not readily apparent, until a locate is performed by an Air Force contractor at the structure sites. Structures had to be moved several times to meet the 100 foot requirement. A National Grassland is interspersed with private lands throughout the production field. The sub-transmission lines were routed around the National Grassland parcels to avoid permitting delays associated with crossing federal lands. Daily coordination with the oil and gas company's pipeline construction personnel was essential to avoid construction delays due to conflicts between pipeline and powerline construction.

As previously stated, a loading study determined that at full build out each section would require up to 7MVA of transformer capacity and as a result a skid substation site would need to be located in every section. The skid substation site consisted of two substation transition (ST) structures spaced 100 feet apart. The skid substation sites required a relatively level location to minimize grading. They also required good access for bringing in the skid substation. Skid substation sites are left in greenfield condition until a skid substation is installed (Figure 12).

Installation

The ST structure (Figure 14) was designed to be a tangent structure for both the sub-transmission and distribution lines. The tangent design simplified construction and helped keep the skid substation footprint within a 40 foot ROW. The sub-transmission phases are stacked vertically on the outside of the taller pole, while the distribution phases and neutral are mounted to a crossarm between the taller and shorter pole.

When a skid substation is to be installed at a location, the site is prepared as if it were a new open-air substation installation. This site work included grading the site, installing compacted structural fill, and ensuring that drainage was away from the pad. In addition, a ground grid was installed to ensure no touch or step potentials would be violated to ensure personnel safety. The skid sub was then either craned or skidded, if overhead conductors were present, into position. The skids are oriented at a 15 degree angle to the sub-transmission line centerline to facilitate proper alignment with the high-side flying tap pole and the low-side jumpers to the 12.5kV underbuild conductors. A separate pole is installed at a 20 foot offset from the taller pole on the ST structure. A “flying tap” of the sub-transmission is made to connect to the high-side of the skid sub using the separate offset pole. Jumpers are then run from the low-side of the skid sub to the 12.5kV underbuild. Finally, the skid substation site had top rock installed and a fence erected per RUS standards. Figures 13 and 15 depict a complete skid substation.

The final step to serving the industrial loads involved designing 12.5kV service drops from the sub-transmission system to the well pads and other production facilities. The typical loads ranged from 500 to 3000 kVA per well pad. A mixture of overhead and underground service drops were used to feed the well pad loads. Overhead service drops over roads required greater overhead clearances to allow for moving partially disassembled drill rigs. The oil and gas company’s operations personnel added and changed the priorities for acquiring power to well pads on an almost daily basis.

Conclusion

The skid mounted substation was designed to be highly mobile with a small footprint that would fit within a powerline Right-of-Way as narrow as 40 feet. In addition, the skid mounted substation was designed similar to an open-air substation. This minimizes the amount of additional training required to operate the substation and helped to maintain the safe working practices already associated with open-air substations. The skid mounted substation provided both utilities with an effective approach to serving the oil and gas loads in their service territories without creating large quantities of excess equipment.

The recent drop in oil prices may have slowed down the pace of new development, but it has not eliminated the need to power the existing oil and gas production infrastructure associated with the recent boom. The above approach to electric system design provides an economical method for a utility to grow and move with industrial oil and gas production loads.

Figure 1 - Example of Utility Mobile Transformer

Figure 2 – Example of Utility Mobile Transformer

Figure 3 – Example of Mining Skid Transformer

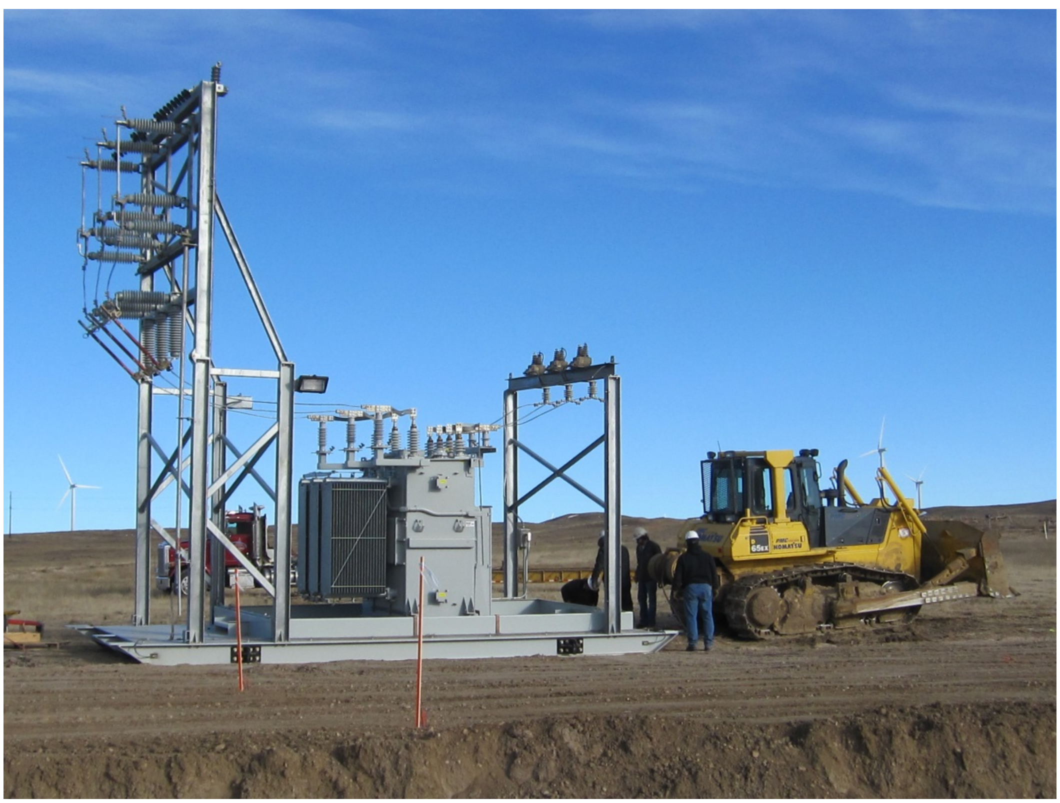
Figure 4 – High-Side Skid being “skidded” into position

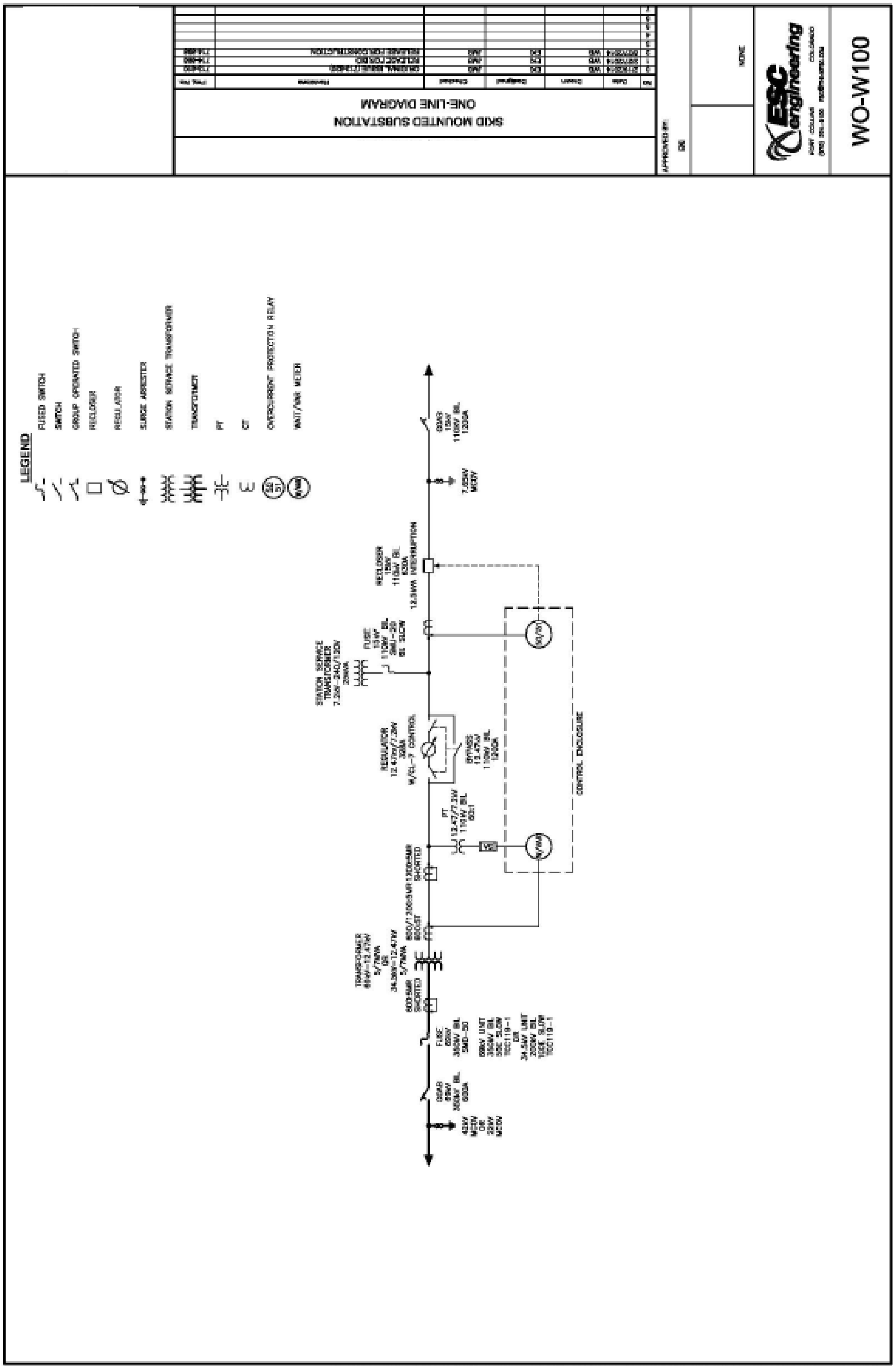

Figure 5 – Substation One-Line Diagram

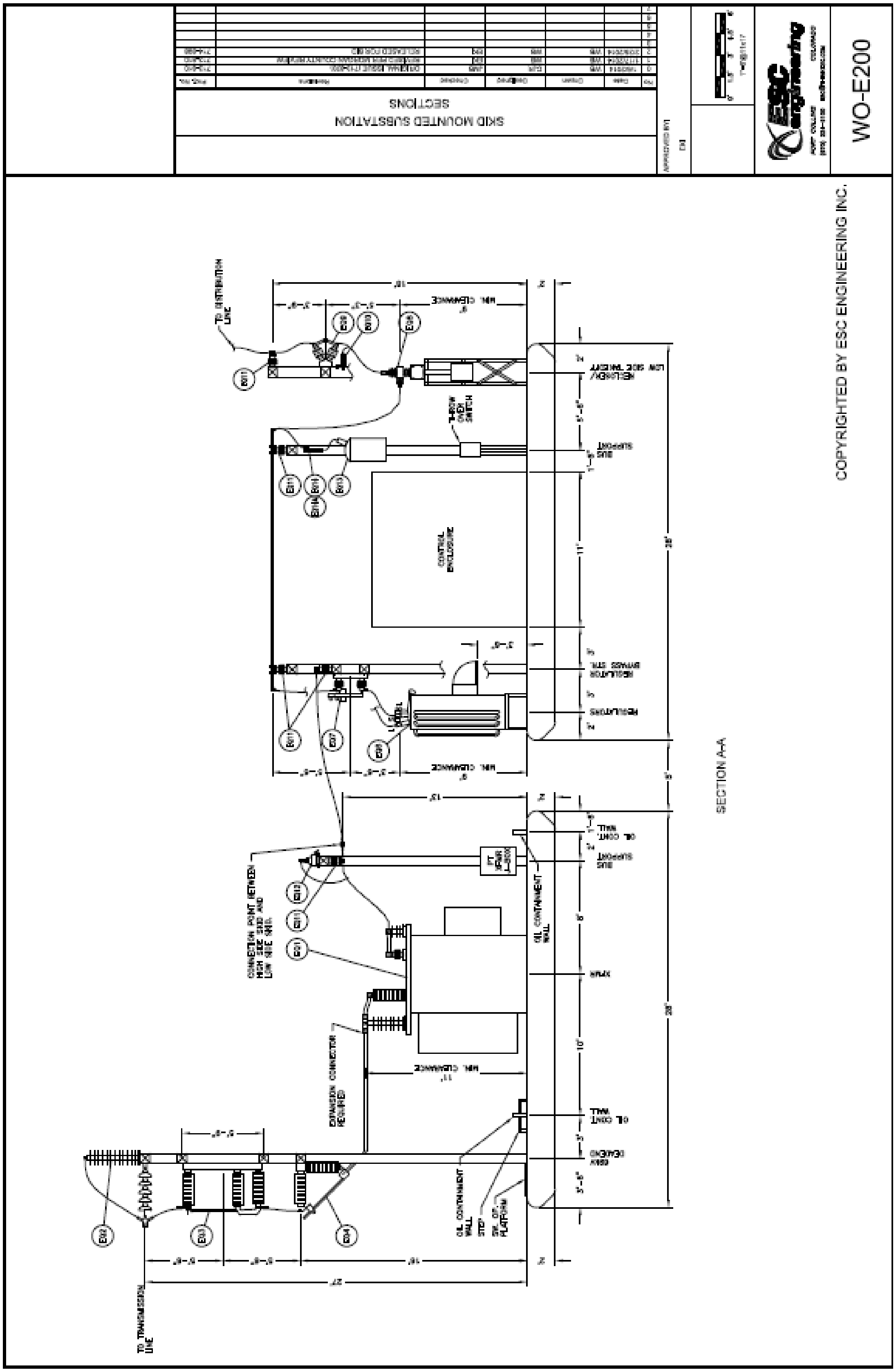

Figure 6 – Preliminary Skid Mounted Substation Elevation

Figure 7 – Skid Substation High-Side, Road Transportation Configuration

Figure 8 – Skid Substation High-Side, Complete

Figure 9 – Skid Substation Low-Side, Road Transportation Configuration

Figure 10 – Skid Substation Low-Side, Complete

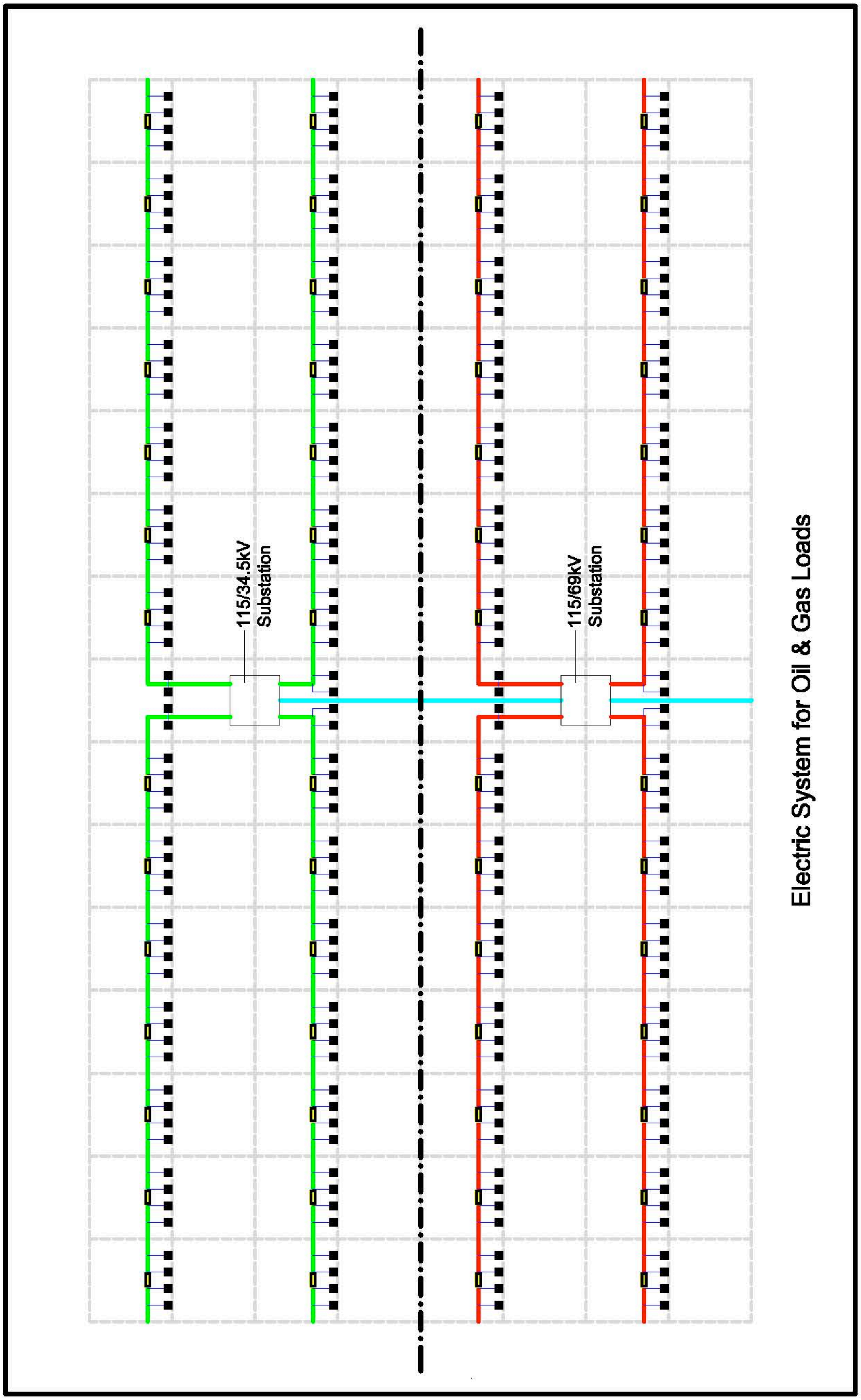

Figure 11 – Electric System

Figure 12 – Greenfield Skid Substation Site

Figure 13 – Complete Skid Substation

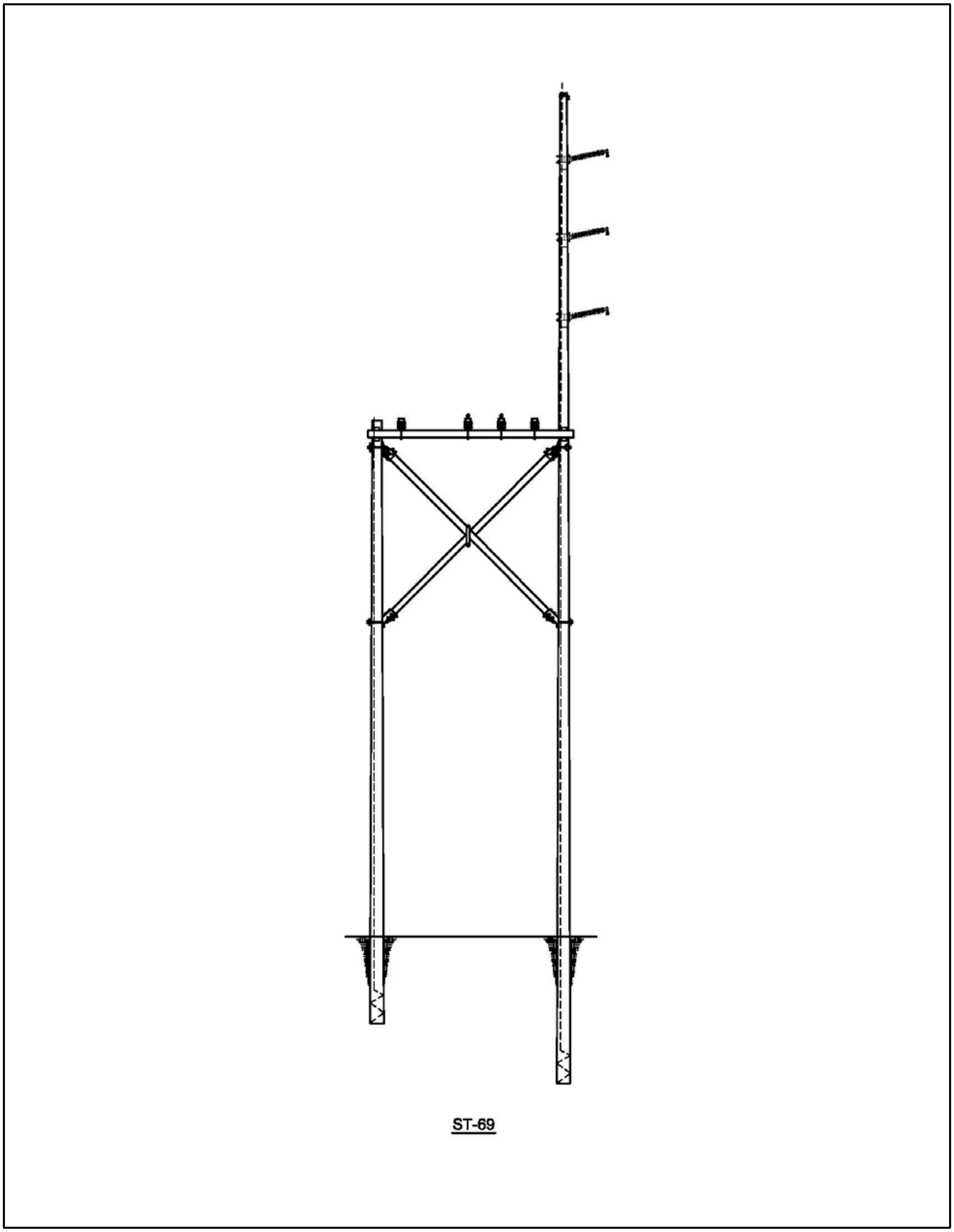

Figure 14 – Skid Substation Transition Structure

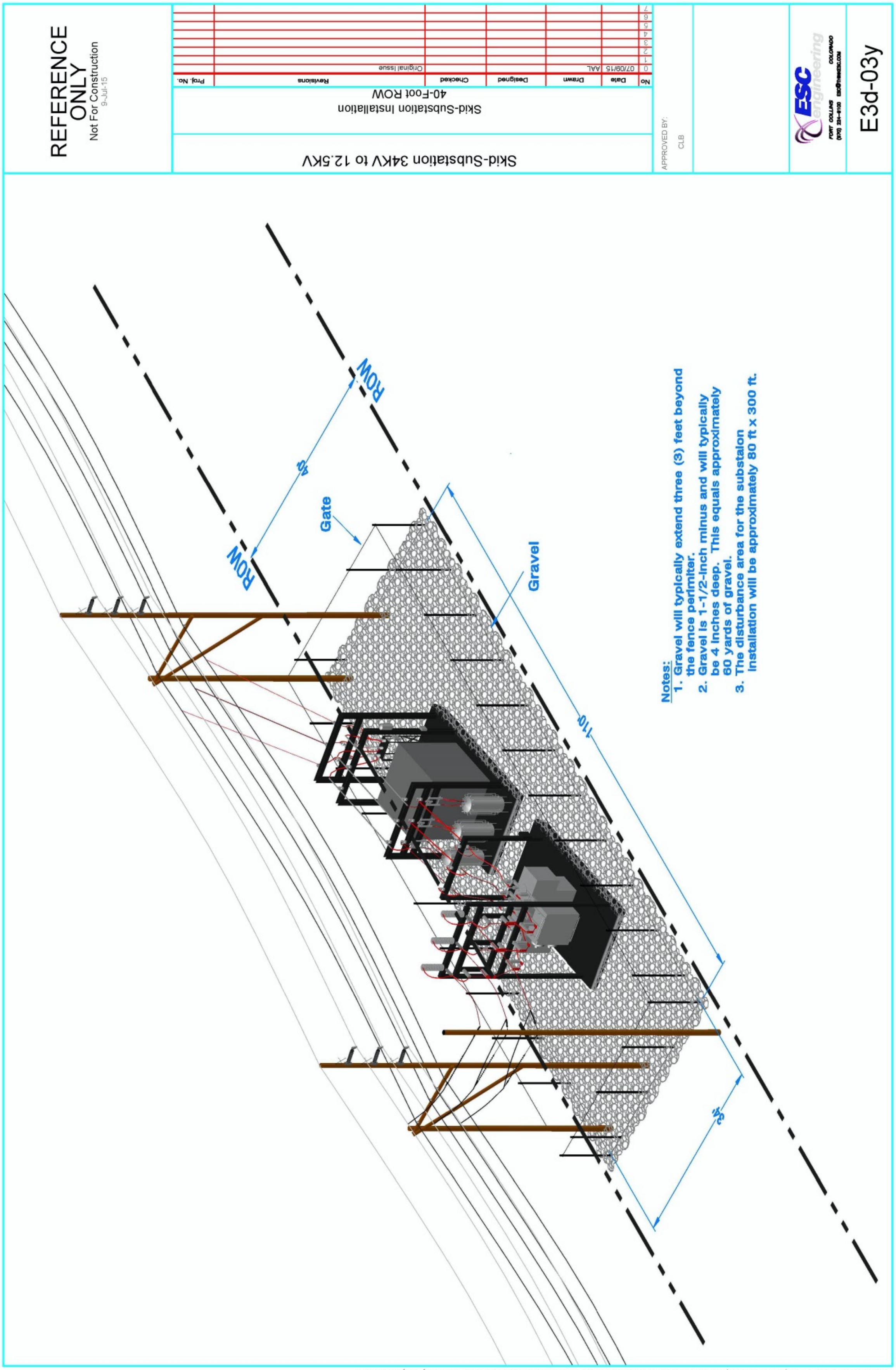

Figure 15 – Skid Substation 3D

Relevant Aspects for the Proper Selection and Application of Transmission Line Arresters for Improvement of the Transmission Lines Lightning Performance

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I. INTRODUCTION

The quality and reliability of a power system is related to its ability to supply continuous and uninterrupted energy without significant momentary disturbances. Several factors may affect the indexes of energy quality, such as the system performance against lightning discharges, its configuration and operation characteristics. In this context, lightning has been reported in many countries as the major cause of non-scheduled outages on overhead unshielded and shielded sub-transmission and transmission lines with rated voltages up to 245 kV, being responsible for approximately 30 – 70% of the outages and creating many issues for power supply utilities and consumers.

Although it is a fact that most of the non-scheduled outages are transitory in nature, in many cases this is still deemed, by power supply utilities and their customers, to be unacceptable. Power supply utilities themselves have verified load losses due to voltage sags on their systems from transitory outages caused by lightning activity. In some regions they have found serious permanent damage on the system itself due to these disturbances occurring on important lines. Loss of power supply is critical for all modern industries, especially today as these customers are more reliant on sophisticated electronic equipment and special production processes which are very sensitive to momentary disturbances on the system.

Lightning activities are more critical for transmission lines up to 245 kV. However, the fact is that even higher systems voltages are exposed to the effects from lightning [1]. This fact has been taken up by several power supply utilities and industrial consumers which have lead them to invest in the promotion of improvements along the critical sections of their overhead lines with poorer lightning performance, thereby increasing their reliability [2-3].

Line arresters (LA) installed along the critical sections of the lines with poorer lightning performance have been used for many years to improve reliability of transmission lines, being usually considered as the most effective among the methods for improvement the overhead lines lightning performance. The majority of Line Arresters installed are for protection of lines against lightning causing back flashover on the towers or shielding failure on the conductors. Growing is also the usage of Line Arresters to substitute shield wires for lightning protection of unshielded lines especially in areas with very high footing impedance [4-7] as well as for using instead of reclosing resistors in cases of application for switching overvoltage control and to build compact lines or upgrade existing lines [8-9]. Still they have not been used to their full potential although many publications have been presented promoting their applications [10].

Line Arresters are electrically connected in parallel with the insulators strings and its lightning protection philosophy consists in reducing the transitory overvoltages across the insulators strings, avoiding this way that their insulation level be exceeded. Line Arresters can be applied to improve the lightning performance of new overhead lines as well as of existing overhead shielded and unshielded lines.

However, in order to get a good solution on the technical and economical prospective, studies have been performed to: select properly the line arresters in terms of electrical and mechanical requirements as well as evaluate the design for longer term performance, especially in regions with higher lightning incidence and critical environmental conditions; and optimize the quantity and location of the Line Arresters along the critical sections of the line.

II. LIGHTNING ON TRANSMISSION LINES AND ITS EFFECTS

Lightning phenomena on overhead sub-transmission and transmission lines have important consequences in many safety and technical aspects. The problem has special importance in countries and/or in regions with high lightning activities and with unfavorable electric parameters of soil.

The frequency in which lightning discharges strike on overhead lines depends on some factors and has a strong influence of the environmental conditions: Ground Flash Density level (GFD) for the region crossed by the entire route of the line; physical dimensions of the overhead line in special its towers height and length of the line; presence of naturally shielding objects or other lines within the same corridor, etc. Besides, the transmission line lightning performance usually can vary at each year, depending on the lightning activities of the region crossed by the line.

Environmental conditions highly affect the power system reliability, and the lightning performance of the power installations seems to be unsatisfactory and disagree, sometimes, with conventional performance predictions and simulations [11]. Since the environment where the entire route of the transmission line is inserted has a direct influence in the lightning activities and in the quality and reliability of the power supply, many technical publications have been presented aiming the monitoring of the lightning activities and their effects on overhead lines [12-13].

Three main groups of aspects are involved in the theoretical analysis of transmission lines lightning performance [14]: those related to the lightning current characteristics (e.g. peak value, time-to-crest and rise-time); those related to the attachment process between lightning channel and transmission line components; and those related to the electromagnetic response of the line struck by the lightning.

The transient behaviour of an overhead line struck by lightning depends on several parameters and factors which need to be take into account during the theoretical studies to evaluate its lightning performance [2], [14-15]: the discharge incidence point; the lightning current characteristic: its magnitude, wave shape and rise time; the transient response of the tower; the electromagnetic coupling among shield wires and phase conductors (for shielded lines); the distance from the tower reached to the adjacent towers; the grounding system response for fast transients; altitude of the tower reached by the lightning, etc. Overhead lines may present several different configurations for the towers, overhead conductors and tower-footing, which establish different transitory responses under lightning stress.

Many technical research programs have been developed in order to obtain a better knowledge of the transient phenomena associated with the lightning striking on shielded and unshielded overhead lines. Most of these studies are basically addressed in the optimization of the lightning protection for overhead transmission and sub-transmission lines; in the evaluation, better understanding and monitoring of the lightning activities and their effects on overhead lines; and in the evaluation, better theoretical understanding and improvements of the grounding systems behaviour for fast transients.

Lightning discharges striking on the transmission lines produce transitory overvoltages across the insulators strings. Flashover on unshielded overhead lines or due to shielding failure on shielded lines or back flashover on shielded lines occurs if the transient overvoltages across the insulators strings exceed their disruptive voltage. The lightning effect on transmission lines can be more critical in regions with higher electrical activities (higher Ground Flash Density) and higher soil resistivity.

Computational models and methodologies have been developed to evaluate the lightning response of overhead lines, some of them taking into account the interaction of all components presented in the line [14-18]. TLA characteristics as well as the procedures to optimize the quantity and application points shall be obtained through transient studies. Basically two different studies have been performed: (1) – study to estimative the transmission line lightning performance for different line configurations; (2) studies to define the energy level absorbed by the Line Arresters considering the lightning characteristics, the grounding system behaviour for fast transients and the probability of multiple strokes occurrence.

Starting from the results obtained in the theoretical studies and knowing the target number of outages desired for the line to be evaluated, it is possible to define the methods and procedures more appropriate to improve the lightning performance of the overhead line considered. Today there are specific software and transient programs available that help the customer to select the proper energy class, position and on which phases the Line Arresters are to be installed, in order to make the best contribution [7], [10], [17-23].A technical evaluation should be usually followed by an economic analysis, allowing to the user to analyse and optimize the cost – benefit balance. Among the methods used to improve the overhead lines lightning performance, Line Arresters have been usually considered in most of the cases as the most effective. Sometimes, its effectiveness and cost – benefit balance increases with the improvement of the tower footing impedance for fast transients associated with Line Arresters application.

III. LINE ARRESTERS TYPES AND APPLICATIONS

There are two different concepts and designs of Line Arresters [21], [24]: Externally Gapped Line Arresters (EGLA) and Non-Gapped Line Arresters (NGLA). Both designs have their advantages and weaknesses, but few publications are written on how to improve those weaknesses. For both designs the essential requirements for the arresters units are [24]: (1) – it must contain zinc-oxide disc elements; (2) - the mechanical constructive design must have short-circuit capability for the safety at the instant of the eventual Line Arresters overloading; (3) – the arresters units shall have enough mechanical strength considering mechanical stress during the operation.

The EGLA concept consists of a gapless arrester (in most of the time with lower rated voltage and lower MCOV) in series with an external gap. The gapless arrester units used in the assembling of the EGLA have the advantage of no continuous voltage stress on the ZnO section and that installation may be sometimes easier because the arresters are both shorter and lighter. One disadvantage is the crucial installation and coordination of the gap sparkover characteristics against the insulation level of the insulators strings (with or without arcing horns) so that the EGLA shall not operate for switching surges and during temporary overvoltages occurrences. Some specific points shall also be checked as the sparkover characteristics of external series gap under different weather conditions and if there is a follow current interrupting capability especially at contamination situations [24].

If an overloaded EGLA is not found, that specific tower will have a lower insulation level than before the installation of EGLA. Arresters units used in the assembling of EGLA typically have ZnO discs corresponding to the IEC distribution type (or IEEE heavy duty type) and therefore shall be used only on shielded lines to prevent back flashover.

In the NGLA concept the gapless arrester is directly connected phase-to-neutral and is continuously energized and conduct small currents, even at normal operating voltage. NGLA concept typically has a higher energy discharge capability and the gapless arresters used as NGLA can have ZnO discs corresponding to previous IEC 60099-4 version LDC 1-4 (IEEE Intermediate or Station Class) which mean that they can protect also the line against switching surges. One advantage of the NGLA concept is the quick response to overvoltages without the discharge time associated with gaps at all weather conditions [24]. In this concept the power system is continuously exposed to overloading of the Line Arresters. In this case, an eventual short-circuit due to NGLA overloading will cause an outage of the overhead line. Therefore, an automatic disconnecting device is required to disconnect a NGLA overloaded from the system. These disconnectors also works to facilitate fast reclosing, but if not properly designed for the actual system conditions these can be more of a weakness, mechanically and electrically, than the real advantage they should be [25].

NGLA can also be used on unshielded lines as a substitute for shield wires [4-7] as well as can be used instead of reclosing resistors in cases of application for switching overvoltage control and to build compact lines or upgrade existing lines [8-9].

When comparing EGLA and NGLA concepts, it has to be taken into account the energy capabilities of both (and not a comparison Distribution vs. Intermediate or Station Class). The hardware for the EGLA is usually more complex than for the NGLA.

The next sections refer basically to the application of NGLA concept, which as described above has the special advantages to protect also against switching surges and typically with higher energy discharge capability.

IV. PROPER SELECTION FOR NON GAPPED LINE ARRESTERS (NGLA): ELECTRICAL AND MECHANICAL REQUIREMENTS FOR LONG TERM PERFORMANCE

The proper selection for NGLA in terms of electrical and mechanical requirements as well as the proper design are important requirements to guarantee the long term performance especially in regions with higher lightning incidence and critical environmental conditions. Common misunderstandings for the selection of Line Arresters are discussed and how important it is to have the goals for the proper installation before specifying the Line Arresters. Details about the importance of the proper coordination between the NGLA and the disconnectors characteristics for an optimized selection is also presented and discussed in this section.

A. Electrical Requirements

A common misunderstanding is to use for the Line Arresters the same specification used for the substation arresters [25]. Substation arresters are electrically selected to handle all kinds of stress from slow front switching events to fast front overvoltages from lightning strikes on incoming lines. To guarantee longer lifetime for the substation equipment protected by the arresters, is beneficial to have as low protection levels as possible, because the insulation of the most important substation equipment is type not self-restoring and repeated impulse voltages may age its internal insulation. The rated voltage for these arresters is selected as a balance among the maximum continuous operating voltage, temporary overvoltages (TOV) requirements and protection levels. The energy requirements come from transmission line discharges during close and reclose of the lines, capacitor bank discharges, or sometimes TOV requirements.

Line Arresters are selected on different criteria. First of all the intended application has to be decided: protection against lightning strikes only or also protection against switching events. We here look at the most common application that is lightning protection. Early indication/decisions needed for the proper electrical selection of the Line Arresters installed are:

- Outage rate acceptable for the specific line: This define how many Line Arresters are needed and in what phases and/or towers.
- Acceptable failure rate of line arresters due to excessive lightning energies: This define the energy class requirement for the Line Arresters.

The sole purpose of Line Arresters for lightning protection is to prevent disruptive discharge (flashover or back flashover) of the insulators strings in their specific tower. Hence extremely low protection levels well below the flashover withstand voltages of the insulator has no benefit at all. On the contrary, it will give some disadvantages, as the Line Arresters must then be capable to handle both possible TOV and switching stresses already taken care of by the substation arresters, leading to a higher energy class than actually needed.

Due to the statistical behavior of lightning there is always a risk that the Line Arresters can be overloaded by severe lightning energies independent of arrester class. The selected energy class depends on whether the specific overhead line has shield wires or not, as the risk for excessive energy is much higher for unshielded lines. The tower footing resistance value of the tower to be protected with Line Arresters is also an important parameter to be considered for defining the energy absorbed by the Line Arresters. For shielded lines, higher tower footing resistance values usually mean higher energy absorbed by the Line Arresters, while for unshielded lines lower tower footing resistance values generally increase the energy absorbed by them.

A typical recommendation for unshielded lines is an energy equivalent to previous IEC LDC 3 or 4 (IEEE Station Class Arresters) depending on the Ground Flash Density (GFD) of the region. Shielded overhead lines usually need an energy equivalent to previous LDC 1-3 (IEEE Intermediate or Station Class Arresters) depending on GFD of the region crossed by the line and on the tower footing resistance values.

Selection of rated voltage is not critical as long as it is usually selected above the rated voltage for the substation arresters, which is explained during the analysis of the disconnector's application. This also has the advantage that grading rings can be smaller for NGLA installations. Many times rated voltage comes out automatically from the selection of protection levels and arrester heights.

When evaluating the insulation coordination analysis between the Line Arresters (NGLA) and the insulators strings, the withstand levels of the insulators strings are typically much higher than the Line Arresters protection levels, especially as separation effects are small. In addition the line insulation is self-restoring. A protective margin of 20-25% for a 20 kA, 1/2 μs impulse wave shape is usually enough. Analysis considering a protective margin of 20% for a 40 kA, 8/20 μs impulse wave shape has also been considered and usually leads to reliable protection. In areas with GFD of 30 or more flashes per square kilometre per year a margin of 15-20% for a current impulse of 40 kA, 1/2 μs impulse wave shape may be needed [25].

During the insulation coordination analysis is also important to take into account the effect of the lead connection length which may impact in substantial increasing of the transient voltage across the insulators strings, especially for higher discharge current steepness.

B. Mechanical Requirements

An essential aspect for the Line Arrester using NGLA concept is the mechanical design. It has been observed failures due to installations related to the configurations chosen [2], [26].

Usually, the type of installation is chosen by the customer experience as well as visual aspects, tower geometry, clearances, and, one of the main reasons, the financial aspects. The environmental conditions like altitude, pollution and ice also can influence the decision. The cost aspect will drive different projects being the voltage level/reliability the main user parameters. The material of the component applied (for instance, at some cases, galvanized steel vs. aluminium vs. stainless steel) will change with the budget, installation place and conductors material.

The main installation types are: Suspended on the conductor; Mounted on the insulator; Suspended on the tower; and Supported in the tower. From mechanical aspects, it is usually recommended to install the arresters mounted on the insulator or supported in the tower but it can varies depending on the project.

When suspended by the conductor, the type of clamp used is very important. The usage of suspension clamps is more recommended than hot line clamps to hang the arrester in the cable due to vibration and torsional stresses. Providing several degrees of freedom allows the part to move freely when submitted to different mechanical stresses (for example, vibrations and wind). Another aspect is related to the connection at the second end of arrester at the suspended installation. It is reported failures due to braid failure, breaks at the lugs as well as deformation of the chain (when used) [26].

Mechanical failures on the disconnectors due to mechanical forces exceeding the proven loading of the arrester components and due to aeolian forces causing failure of the mechanical fittings associated with the arrester, leading to a disconnector operation has also been reported. The mechanical testing must consider both possible fatigue due to swinging of the lines and load stresses from the power lines due to wind, ice, and magnetic forces.

As a good practice, the disconnector shall be installed in a position where it is more exposed to tension than cantilever forces. However, the maximum force applied has also to be considered to avoid mechanical failure.

The hanging arresters interact with the other line components including the dampers. Usually, the vibrations in the line are separated by Aeolian, galloping or sub-span due to different causes. The sub-span is only applied for lines with conductor bundles and the galloping happens due to the asymmetric ice deposition at the conductors combined with the wind.

Table I shows details of some typical parameters associated with vibration in the line for the three causes mentioned above.

Table I - Typical parameters associated with vibration in the line due to Aeolian, galloping or sub-span

	Aeolian	Galloping	Sub-span
Frequency (Hz)	3-100	0.1-3	0.15-10
Amplitude (conductor ∅)	0.01-1	5-300	0.5-20
Wind speed (km/h)	3-25	25-65	15-65

In order to control resonance conditions, the natural pendulum frequency of the arrester shall be compared to the span natural frequencies. According to [26], the pendulum frequency of an arrester is given by:

$$f = \frac{1}{2\pi}\sqrt{\frac{3g}{2h}}$$

where g is the standard gravitational acceleration (9.8 m/s^2) and h is the arrester height (m). From this formula, it can be seen in the Table II that the resonance happens at lower frequencies.

Table II – Resonance frequency for different arrester's heights

Arrester height (m)	Frequency (Hz)
0.25	1.22
1	0.61
2	0.43
3	0.35
4	0.31

The conductor vibration frequencies are related to several aspects like: the conductor size; the span length; conductor tension; conductor weight and standing vibration loops; and the excitation type being considered. The natural frequency of the conductor or overhead shield wire is [27]:

$$f = \left(\sqrt{\frac{T.g}{w}}\right) . \frac{n}{2.S}$$

where f is the natural frequency, T is the tension, g is the standard gravitational acceleration, w is the conductor weight, n is the number of standing wave loops and S is the span length.

From the mechanical perspective, lighter and shorter arresters are easier to install in the line. In that sense, unnecessary withstand voltages or creepage distances should not be adopted in the projects.

The coordination of the arresters with the line vibration dampers is also important. The dampers are usually placed at the anti-nodes of the vibration wave (for example, at a distance of 80% of the Aeolian vibration highest frequency loop to the insulators clamps). When placed at the line, the arrester changes the configuration of the vibration loops and, for that reason, it is recommended to install another vibration damper between the arrester and the clamp. It is a common practice to install a damper at each side of the arrester but it can be adopted the same rule of a damper installation at a 80% distance but, in this case, from the arrester installed outside of the original damper [26].

C. **Disconnector Characteristics: Proper Coordination with NGLA**

Disconnectors have been widely used for many years for distribution arresters on distribution systems in conjunction with fuse links. However, for Line Arresters applications using NGLA concept need specially designed disconnectors to successfully operate for all of the different Line Arrester applications. The reliability requirements on the disconnectors used on overhead sub-transmission and transmission lines are more stringent than their traditional usage for distribution arresters.

The two most important electrical characteristics of a disconnector are how fast it operates and that once triggered it must continue its operation even if the voltage is switched off. The faster it operates the more sensitive it becomes for power frequency voltage stresses meaning that it is important that all TOV stresses of the NGLA should be kept to an absolute minimum. Hence the necessity to have a higher rated voltage of the NGLA when you want a fast and robust disconnector operation.

Important disconnector characteristics are of course how fast it can operate typically shown as a curve of current versus time. Figure I shows the curve for a specific disconnector used for NGLA applications from previous IEC LDC 1-4 (IEEE Intermediate and Station Class).

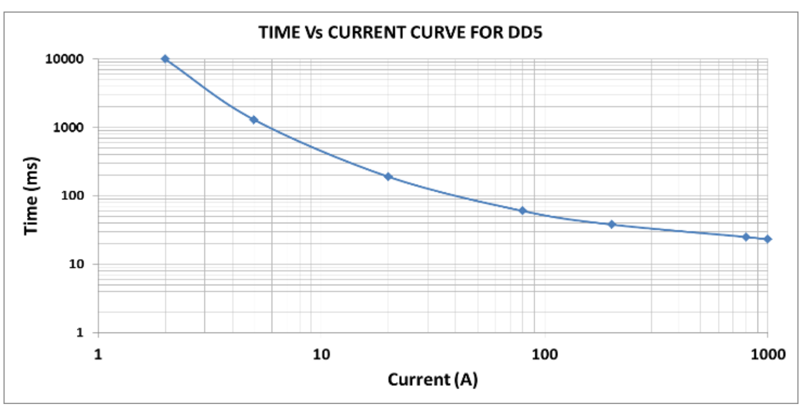

Figure I – Disconnector opening time (ms) versus current (A)

Equally important is that once triggered to operate it must fulfil its operation independent if the system voltage is switched off or not. Especially some distribution disconnectors may stop its disconnection operation if the system voltage disappears.

It shall also be pointed out that a disconnector cannot be used as a substitute for a circuit breaker to clear an overloaded NGLA. Its quenching possibilities of the short-circuit arc are very random and vary much dependent on both weather conditions as well as the actual installation.

There are three tests which are important for the operation and selection of disconnectors applied on NGLA [25]: (1) - When the disconnector shall not operate - This is when an arrester has to withstand all the normal voltage and current stress related to IEC LDC 1-4 (IEEE Intermediate or Station Class Arresters) in all types of NGLA applications; (2) - When the disconnector shall operate -.When the NGLA is in a breakdown mode due to overloading, whereby higher than normal operating currents are passing through the arrester and the disconnector is triggered independent of the line protection system operating before it disconnects or not; (3) - Proper mechanical strength - The NGLA's are subjected to higher mechanical loading than distribution type disconnectors, as the connections are heavier and short-circuit currents may be higher.

The mechanism triggering a disconnector operation is divided into two distinct categories: electrical overloaded of the NGLA; and mechanical failure due to mechanical forces exceeding the proven loading of the arrester components and Aeolian forces causing failure of the mechanical fittings associated with the arrester. However, as these arresters are installed in various overseas territories the precise cause of the incident is not always known.

Electrical overload happens usually due to direct lightning outside of the arresters performance overloading the NGLA. Line Arresters are typically designed for optimum use, where neither worse case scenarios nor shielding failure are generally considered. An overloaded NGLA passes through current to earth. However, this current is negligible when compare to the normal circuit load current and the unbalance return earth circuit current. Therefore the NGLA disconnect operations have no relevance to the power network protection.

The transition from an overloaded to a failed NGLA and the progression of its through current to earth is very rapid. This transitional time is also very random. Eventually a failed NGLA will have a full network short circuit current. The disconnector still operates as described above even if the network protection did not pick up this transitional through current. It will draw a power arc in the process. This power arc may subsequently initiate a follow on earth fault and at this time the circuit will be reinstated by the automatic network switching scheme.

If this earth fault is picked up by the power system protection, it will be dependent upon the protection scheme that was adopted. Modern circuit breakers and switches have interrupter mechanical travel time of around 40 ms or it is roughly two power frequency cycles. It can be deemed this is the ultimate fastest fault clearing time for a power network. Nevertheless a delay between 40 ms and 200 ms is expected between an earth fault detected and all the associated circuit breakers are fully open.

The fast fault clearing time may impose limitation to some type of NGLA disconnectors which has definitive operation time characteristic and requires the through current presented at all time. If the network protection is faster than the disconnector, the NGLA through current would disappear after the voltage is removed and the disconnect operation will not occur. That will leave a worst possible scenario.

It is understood that automatic reclose for the circuit breaker will be applied after a transient fault. The energization directly on to a short circuit would cause a lot of distress to the power network and the switchgears. In order to avoid this situation, a disconnector should have opening characteristics which is as soon as it is called upon to operate by a defined NGLA through current, nothing could interfere its operation disregard the presence of a permanently applied continuous through current from the system voltage or not.

In summary, there are four different scenarios that can happen when a NGLA gets overloaded [25]:

1. Disconnector operates before the line trips: This depends how quick the disconnector operates plus how quickly it can quench the arc during falling out which will be strongly weather dependent. This is then a race between the line protection scheme and the disconnector and may vary from incident to incident.
2. Disconnector operates before fast reclosing of the line: This means that once triggered the disconnector shall continue to disconnect even if the power supply is switched off. This should be a repeatable operation depending on coordination of the line protection scheme including fast reclosing time and the disconnector opening time.
3. Disconnector has not completed its operation when fast reclosing occurs: This should not happen as this leads to a system disturbance and also leads to a second short-circuit stress on the NGLA which significantly increase the risk of complete disintegration of the arrester with larger pieces coming down. This indicates a mismatch of disconnector opening times compared to the line protection scheme of the system and may cause system disturbance every time there is a NGLA failure.
4. A fourth scenario is that the disconnector operates but the arrester is not overloaded or failed. This should not occur and indicates either a disconnector not matching the NGLA characteristics or a mechanically weak disconnector design.

These scenarios show how important it is to coordinate the disconnector operations to both the NGLA characteristics as well as the actual line protection schemes. It also shows that if the system owner changes line protection schemes for lines with installed NGLA possible risk of mismatching the disconnector opening times should be checked with the NGLA supplier.

One critical scenario occurs when the short-circuit currents for a system are low like for ungrounded systems. Disconnectors are simple devices which shall have clear limits, disconnect or do nothing, but low short-circuit currents and high currents flowing through the NGLA during TOV events may look the same from a disconnector perspective. However, for the NGLA it is a clear difference as they shall survive the TOV without triggering a disconnector operation. It shows an important advantage when selecting the rated voltage significantly higher than for the substation arresters. Now the TOV currents through the NGLA will be lower and can therefore be distinguished from short-circuit currents by the disconnector, avoiding risks of a wrong disconnector's operation.

D. Importance of the Proper Design

Line Arresters have been assembled with polymeric gapless arresters. In the NGLA concept the gapless arrester is directly connected phase-to-neutral and is continuously energized and conduct small currents, even at normal operating voltage. Besides having continuously submitted to the power frequency system voltage and, eventually, to transitory stresses, the NGLA are exposed to the most adverse environmental conditions. These different stresses can provoke the degradation and ageing of the gapless arresters under service conditions and, as consequence, an eventual overloading of the NGLA can occur. Although be more critical in the NGLA design, the environmental conditions also can affect the long term performance of EGLA design.

Among the polymeric types, the most used for Line Arresters are: (1) – Separately molding housing that is placed over the core, usually constituted of the ZnO blocks with a fiberglass wrapping (slipped over process). The interface between core and housing is filled with an elastic sealing paste, typically silicone; (2) - Direct molding housing over the core, constituted of the ZnO blocks with a fiberglass wrapping (molded on process); (3) - Direct molding over the ZnO blocks that are supported by fiberglass rods. The first and second types are called "wrapped design", while the third type is known as "cage design".

The most typical cause of the gapless arresters degradation that can lead to the arrester's overloading under critical environmental conditions is related to moisture ingress. For the types described, the typical moisture penetration mechanisms are: (1) by the capillary effect thought the caps and/or sealing system, usually found in slipped over designs; (2) - from internal partial discharges created by voids at the interfaces, that has a strong influence on the manufacturing process; (3) - from diffusion through the polymeric housing, which has a strong influence of the polymers properties / design process.

The weather and electrical conditions may contribute to the ageing and aggravate the moisture ingress. The consequence is an internal current path that will increase the internal leakage current flowing through the internal part of the polymeric housing and can lead to a tracking condition.

Studies to evaluate the polymeric arresters degradation and to predict the long-term performance effects on the severe weather conditions using environmental chambers have shown a strong dependency of the internal constructive design and the polymer properties on the arrester's performance against moisture ingress [28-33]. Studies to evaluate the performance of the polymeric arresters under heavy pollution have also revealed the effect of the constructive design in addition to the effect of the polymer properties [34-35].

Theoretical and experimental studies to evaluate the long term performance for polymeric gapless arresters under severe weather and/or heavy pollution have usually shown the better long term performance for silicone arrester's housings.

V. CONCLUSIONS

- In many countries lightning has been reported as the major cause of non-scheduled outages on overhead unshielded and shielded sub-transmission and transmission lines with rated voltages up to 245 kV. This fact has been taken up by several power supply utilities and industrial consumers which have lead them to invest in the promotion of improvements along the critical sections of their overhead lines with poor lightning performance, thereby increasing their reliability.

- Among the methods used to improve the overhead lines lightning performance, line arresters installed along the critical sections of the lines with poorer lightning performance have been usually considered in most of the cases as the most effective.
- In order to get a good solution in the technical and economical point of view, studies shall be done to select properly the line arresters in terms of electrical and mechanical requirements as well as evaluate the design for longer term performance; and to optimize the quantity and location of the line arresters along the line.

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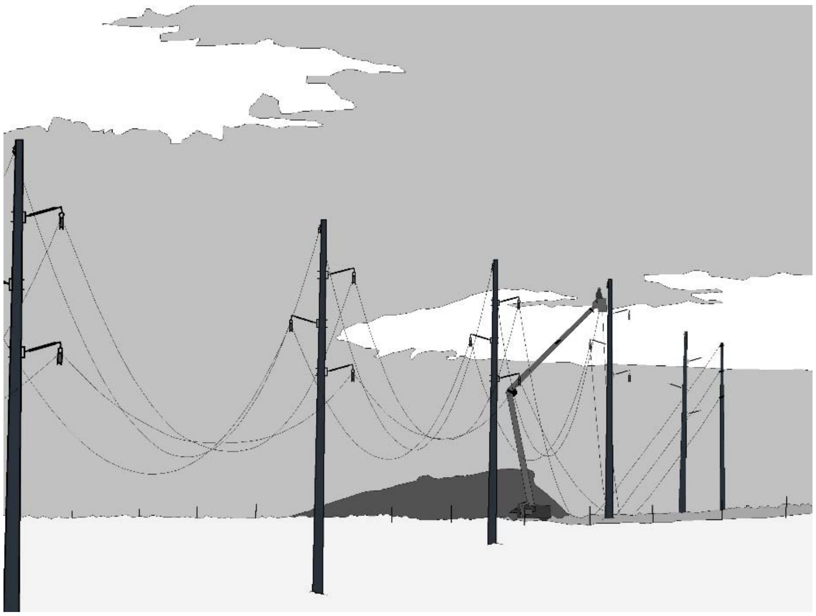
Stringing Methods and Verification



July 2015

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TRC

Table of Contents

1.0 ABSTRACT

The purpose of this paper is to present the different methods of stringing and how they can be used in PLS-CADD to confirm proper stringing was performed by construction. This paper briefly describes the transit method, using a dynamometer and use of the wave return method in order to verify the sag of a wire. It also touches on the importance of the contractor recording the measurements from the chosen method and supplying these records back to the engineer for verification in PLS-CADD. The paper next explains how LiDAR can be used to check the As-Built conditions and the limitations of this method. Through discussing the various methods for checking sag, different approaches are proposed on how to best create a PLS-CADD As-Built model that more accurately matches in the field conditions.

2.0 INTRODUCTION

2.1 Background

With code compliance becoming more and more important along with the heavy fines that can be accumulated from clearance violations, it is now more critical than ever that transmission lines be tensioned properly and according to what is specified by engineering. Under tensioning can cause clearance violations, which can lead to flashovers or even fires. Over tensioning can cause vibration issues and structural failure. These issues can not only be costly for the utility, but can cost contractors significant money to resolve if resulting from improper construction.

2.2 Purpose

This technical paper discusses the various methods for stringing and the importance of verifying the sag of the wire through various methods. Three different stringing methods will be discussed along with the use of LiDAR for post construction verification. The limitations of these methods will also be addressed and methods for verifying the sag in PLS-CADD will be suggested in order to provide better a as-built model.

3.0 STRINGING METHODS

3.1 Transit Method

The transit method consists of using survey equipment to measure the sag of the wire. This method can be done several ways: through direct target sagging, horizontal target sagging, calculated target sagging and calculated angle of sight sagging method. In addition, there are several equations for back calculating the sag from these methods. See below in Figure 1 for a graphic representation of the calculated angle of sight sagging method.

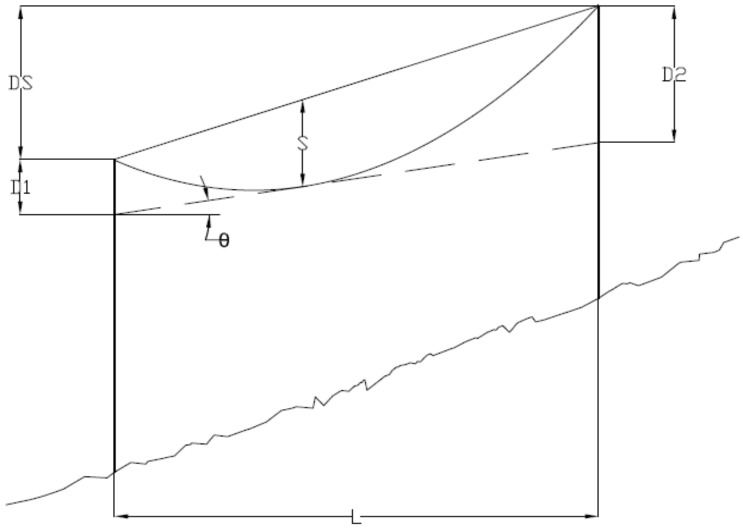


Figure 1 – Calculated Angle of Sight Sagging Method

3.2 Using a Dynamometer

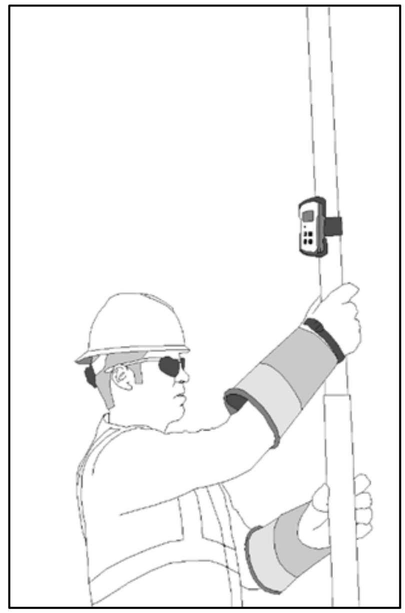
The method of using a dynamometer to determine the tension of a line involves placing a dynamometer in line with the wire similar to Figure 2 below. The dynamometer uses a load cell to measure the tension of the line. The line is either then tightened or loosened until the desired tension is read. The dynamometer method requires the load cell to be placed in line with the wire making the process a bit cumbersome and very difficult to check the tension on existing lines.

Figure 2 – Dynamometer Installation

An additional item to be aware of when using a dynamometer is that the stringing chart tensions provided out of PLS-CADD are horizontal tensions, so if the line is located on hilly or mountainous terrain, these tensions can vary quite a bit from the horizontal tensions provided in the stringing charts. Another limitation of the dynamometer is they can become out of calibration and unless it is checked against another method or another dynamometer this can go unseen causing sagging errors.

3.3 Wave Return Method

The wave return method for measuring sag can be traced back to two men, P. R. Overend and S. Smith, who developed a procedure to determine the sag in a tensioned wire by the use of a stop watch. The variables included in this procedure are the weight of the wire, the length of the span, tension of the wire, the gravitational acceleration, the number of waves being timed and the time recorded for the desired number of waves to be measured. This method is simple but requires an experienced operator to obtain accurate results. The equations used in wave return method can be found below.



Midspan Sag

$D = 48.3 \times (T / 2 \times N)^2$

D = conductor sag in inches
T = time in seconds
N = number of return waves counted

Tension

$T = w \times L^2 / (8 \times S)$

S = mid span sag (ft)
w = weight of wire per length (lb/ft)
L = span length (ft)
T = wire tension (lb)

Pulse Speed

$V = (T \times g / w)^{1/2}$

V = pulse speed (ft/sec)
T = wire tension (lb)
g = gravitational acceleration (32.17 ft/sec)

Pulse Return Time

$RT = 2 \times N \times L / V$

RT = pulse return time (sec)
N = the number of waves being timed
L = span length (ft)
V = pulse speed (ft/sec)

To perform this method, a representative span should be used for the segment of line that the sag is to be determined for. The span must have tangent structures on both sides of the span and be clear of other hanging devices such as dampers, marker balls and bird diverters that will affect the wave. At one end of the span jerk or strike the wire at a distance from the structure attachment that has been determined adequate based on the users experience and check the time to the stringing charts provided by the engineer. Then adjust the tension until the time matches the time on the stringing charts.

3.4 Importance of Temperature

One of the most important factors in sagging a wire or trying to record the sag of an existing line is accurately knowing the temperature of the wire.

One way in which wire temperature can be determined is by using a thermometer and recording the different variables that go into the IEEE Standard 738-2012 method and then performing the calculation. The limitations of this method are the variables may not all be well known, including the weather data if a weather station was used and the weather station is located far from the line or at a different elevation from the line.

A second method for determining the temperature of the wire is by hanging a piece of conductor in the air with a thermometer inside of it and then checking the temperature off and on throughout the stringing process. This method works very well if there is no current on the line and can also be used with the IEEE 738 method by including only the ampacity contribution to the heat of the wire. However, cooling effects due to wind may not be fully realized through this method.

A third method for finding the temperature of the wire is through a thermal camera. This method can be done accurately when the line is being constructed and while it is energized and removes the many variable required from the IEEE 738 method. The thermal camera can be a very useful tool especially in checking the temperature of an energized line, but it may be considered too timely of a method during stringing operation.

3.5 Creep

Creep is another component of sag that is the most difficult to accurately measure. Creep starts occurring once the stringing process begins and usually levels out after ten years depending on weather. Much of the creep of the line happens in the first year after the wire has been installed, but heavy snow and ice along with extreme temperatures can impact the accuracy of estimating creep. Different wire manufacturers have their recommendations on where the wire has creeped based on the time in the air, however, it is recommended that if tensioning the wire occurs beyond 24 hours the wire manufacturer should be contacted to provide adjustments for creep.

Both the contractor and the engineer should be aware of how creep effects the stringing operation and how it effects the computer modeling of existing lines as well at as-built conditions, especially when as-built surveys are performed several months after construction. At this point, the wire is somewhere between initial and max creep conditions and additional information from the wire manufacturer is required to develop an accurate model of the sag. Not taking into account proper adjustments for time and load can cause in-accurate modeling results. A line modeled as fully crept that is actually in-between initial and full creep conditions would result in a model showing a higher tension than originally specified.

4.0 UNIQUE STRINGING SCENARIOS

4.1 Sagging Through Deadend Structures

During stringing operations the contractor may desire to string and sag the wire through one or multiple deadends. This can save time during construction, but can also cause issues if the designer has not planned for this. Good communication between the construction crew and the engineer is very important especially during stringing. A discussion between the engineer and the contractor should be had prior to construction to make sure that the contractor is not planning on sagging the wire through multiple ruling span sections. If in fact the contractor is going to do this the engineer should take steps in PLS-CADD to provide the proper stringing charts. If the sections have similar ruling spans this is not an issue, however, if they have ruling spans that vary, special caution should take place. The best way for the engineer to accommodate this is to model a second line in PLS-CADD for stringing purposes. This line model then should only contain the deadend structures being strung to and from and the deadends being strung through should be modeled as tangent structures. The stringing charts should be taken from the stringing model.

4.2 Sagging Spacer Cable

The sagging and stringing of spacer cable has some unique challenges that the engineer needs to be cognizant of in order to provide proper stringing charts. In the stringing of spacer cable the messenger is strung in and tensioned prior to the conductor being added. This causes issues if the engineer improperly uses the spacer cable file which includes the full weight of both the messenger and insulated spacer cable for developing stringing charts. This issue can be avoided by creating a stringing layer in PLS-CADD and stringing in only the messenger cable. One method to mimic the final condition is to add an ice weather case that will give an equivalent weight of the wire after the conductor has been added. This ice case then should be used for the PLS-CADD automatic sagging criteria weather case, at a representative temperature, in order to match the stringing conditions in the model containing the spacer cable wire file. In doing this method, stringing charts can be created for the messenger cable only, matching what will be done in the field.

5.0 RECORDING OF STRINGING DATA

The construction crew performing the stringing operation should take good records of the stringing operation. Records should be taken for each span that is measured and at a minimum the following data should be recorded.

1. Ambient Temperature
2. Time of Day and Date
3. Atmospheric Conditions, (Cloudy, Industrial or Clear)
4. Wind Speed and Angle
5. Span Being Measured and Span Length

These variables can then be used by the engineer to estimate the temperature of the wire. These variables are specifically important if the IEEE Standard 738 method is being used to find the temperatures. If the other methods discussed above are being used, items 1-4 are not as critical, but the measured temperature of the wire should then be included with each sag data recording.

Depending on the method of sagging being used, the engineer should also receive a chart that includes either the sag of the wire, the tension of the wire or the return wave time. These along with the span length and temperature of the wire will allow the engineer to verify that the tension of the line is adequate for clearances and structure strengths.

It is recommended that each method be double checked. If the line location allows the wave return method, this is a quick and easy approach to verify both the transit method and the use of a dynamometer.

Accurate construction records of the sag of the wire for several spans, along with the temperature, provide the best means for developing the temperature and creep condition that best represent an as-built survey. In cases where the line was surveyed only months after construction making it difficult to judge the creep condition of the wire, the creep charts from the wire manufacturer should be obtained to try and estimate where the creep is at and this can be used to verify the construction sag and temperature records during stringing.

6.0 AS-BUILT MODELING

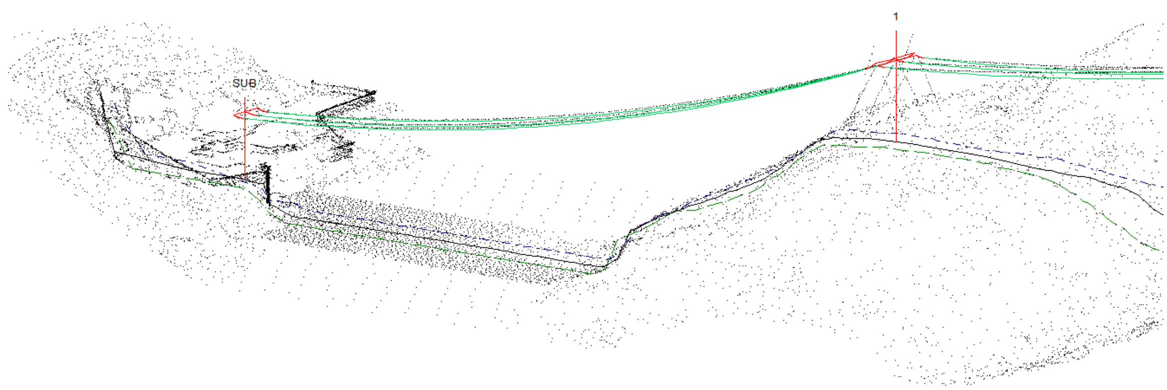
6.1 LiDAR

LiDAR can be a great tool to verify the adequacy of an existing or newly built transmission line. LiDAR consists of surveying, with laser technology, the transmission line and surrounding area creating millions of points and then processing that data to be brought into PLS-CADD so that the line can be modeled and checked. This method allows the engineer to accurately determine the attachment locations of the wire and when used in congruence with the construction records for sagging, if they exist, can provide a very accurate model of the existing conditions.

An issue that can arise with modeling a line purely on aerial LiDAR is that the temperature of the wire can be difficult to obtain. As discussed above, weather data from a weather station is often used and depending on the proximity of the line to the weather station, this data can be very different from the weather experienced on the line. This becomes even more of a factor when a line crosses through mountainous terrain where the weather station is far from the line and the elevation change can have a great effect on the temperature. In addition, if the line is carrying current, further calculations need to be performed as the wire temperature may vary greatly from the air temperature. The other issue with LiDAR is the fact the line will have creeped and depending on how long ago the line was built the creep can be hard to predict.

6.2 PLS-CADD Modeling

With the computing power and emerging technology it is now easier than ever to produce an As-Built model of the transmission line. This is very important as clearance violations can be very costly and structure failures can be not only costly to the utility but also to consumers having power outages. With the use of LiDAR to verify structure locations and attachment points the engineer can create a very spatially accurate model of the line. However, as discussed above the unknown factors in determining the temperature of the wire and the creep of the line can cause inaccuracies in the modeling. This is why using the construction records to model the wire tension in the As-Built model is one of the best methods. During construction conditions an accurate temperature of the line should be recordable and the wire will have little to no creep compared to when the LiDAR is flown months after construction is completed. With the creep being much closer to initial condition during stringing operations, using the recorded stringing values allows for a much more accurate model of the line to be created. In addition, it is a good idea to check the construction records against those found from the predicted LiDAR data line temperature and creep.



7.0 CONCLUSION

As discussed, several methods exist for verifying that a transmission line was properly sagged during construction and each of these methods has its own limitations in regards to accuracy. It is now becoming more and more common for utilities to survey a line either through conventional survey or LiDAR shortly after construction to ensure clearances are met. To ensure that an accurate PLS-CADD model is developed, it is critical that contractors understand and employ the best method for obtaining wire sags and temperatures during construction. This data can then be used as the base point for developing the appropriate wire temperature and creep condition to use for modeling to the post-construction survey data. Although IEEE 738 is a useful tool it often requires many assumptions to be made which can greatly compromise the accuracy of the model.

REFERENCES

IEEE Standard 738-2012, “IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors”, 2012

UEP_Bulletin_1726C-115, “Checking Sag in a Conductor by the Return Wave Method”, 1992

The Critical Role Nondestructive Testing Plays in the Steel Utility Pole Industry

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Abstract

Nondestructive testing has become an integral part of the process when determining the remaining lifespan of in-service steel utility pole structures and plays an essential role in the manufacturing of new replacement structures. The nation's critical utility infrastructure has come to rely on nondestructive testing even more as it ages and the service life of structures is pushed to its limits. However, with the probability of detection of defects at an alarming low percentage, it is critically important for utility personnel to understand the various methods of nondestructive testing that can be employed and their limitations. This paper/presentation will discuss the advantages and disadvantages of each method as well as their correct employment in a plant versus a field environment. And finally, it will attempt to address some key points:

1) What are the appropriate training requirements and certifications necessary to insure that personnel inspecting your steel utility poles know how to perform these tasks correctly?
2) What types of defects should they be looking for?
3) How to properly evaluate findings to ensure critical defects are located.
4) Repairing defects while not doing more harm to the structure.

The Critical Role Nondestructive Testing Plays in the Steel Utility Pole Industry

Introduction

When we flip the light switch, the light turns on 99.9% of the time. As a society, we have generally come to take this for granted. The electrical grid in the United States consists of an estimated almost 400,000 miles of transmission lines, some of which date back to the 1880's.[1] With this aging infrastructure comes a need for forecasting the lifespan of existing utility structures along with the manufacture of utility structures for both new construction and replacement of in-service lines. Nondestructive testing has become an essential component in the inspection of in-service structures while playing a critical role in the quality control during manufacturing. As inspections are used to find discontinuities, cracks or other potential damage in a physical structure, it is important to know the strengths and weaknesses of each method of NDT as this will allow a properly trained and certified technician to select the right method to employ and then perform this testing accurately. Electrical demand will continue to grow over the coming years, and with it, the need for proper Nondestructive Testing in the utility industry will continue to expand as well.

What is NDT?

There are numerous technical definitions of Nondestructive Testing (NDT), yet we feel that its simplest form is by far the best and most concise - NDT allows materials and components to be inspected and assessed without any physical damage to them.

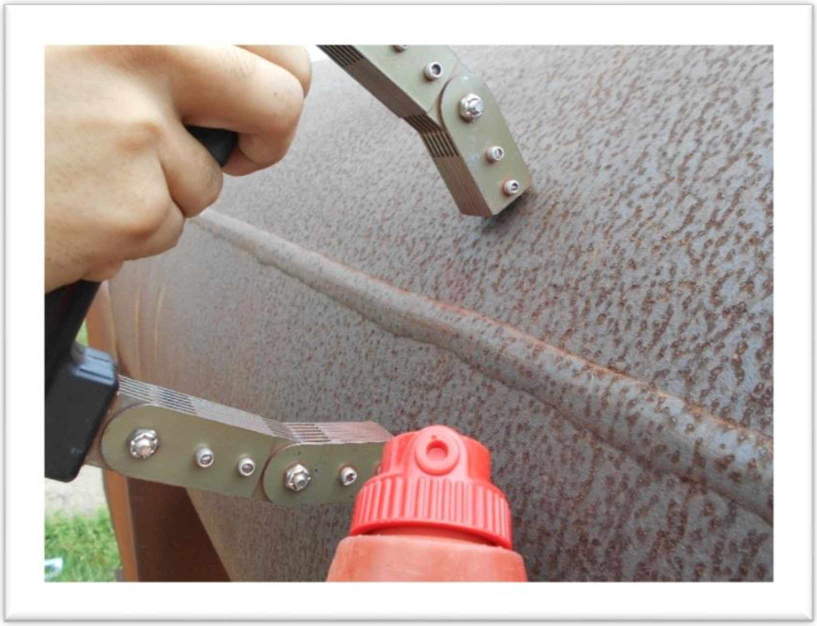
NDT Methods

While the American Society for Nondestructive Testing (ASNT) recognizes nine major methods along with several other subcategories, this presentation will be focusing on the three primary methods used in the inspection and manufacturing of steel utility poles: Magnetic Particle Testing (MT), Ultrasonic Testing (UT) and the often overlooked Visual Testing (VT).

Magnetic Particle Testing (MT)

Magnetic Particle Testing (MT) uses magnetic fields to locate surface and near surface discontinuities in ferromagnetic materials such as steel. In the steel pole industry, the magnetic field is applied indirectly, most commonly with a yoke. Once the magnetic field is established, a fine pigmented ferromagnetic powder is applied to the surface of the part, which will be drawn into the magnetic leakage field caused by a discontinuity, causing a visible indication.

[1] ASCE – "2013 America's Report Card for Infrastructure"



Magnetic Particle Testing (MT) Conducted on a Long Seam.

MT equipment is inexpensive to purchase and operate, is portable and it is relatively easy to train personnel in its use. MT does have its downsides as it is only suitable for surface breaking and near surface discontinuities, can only be used on ferromagnetic materials and can be misevaluated without proper training. Proper initial and ongoing training will teach a technician to tell the difference between a relevant indication and a false indication that could lead to hours of re-work during fabrication.

Relevant or Irrelevant Indication? Should this be Repaired?

Ultrasonic Testing (UT)

Ultrasonic Testing (UT) introduces sound waves to the part or item being tested via a transducer made up of a piezoelectric crystal that converts electrical current to sound waves. The sound traveling through a part hits material with a different acoustical impedance and some of the sound will reflect back, be received by the unit and represented as an indication on the screen. Knowing the velocity at which sound travels through a part, along with the time of travel results in a distance to the indication.

Ultrasonic Testing (UT) of a Newly Installed Gusset.

Ultrasonic testing is a portable method of inspection, gives consistent results and can detect both surface and subsurface indications. As such it is well suited for weld inspection in both manufacturing and field environments. While significantly more expensive than MT to train and equip a technician, UT is still cost effective and can provide an extreme level of detail. UT has significantly higher requirements for both classroom and field training than MT and without proper training, misinterpretation of findings can occur with dire consequences.

Visual Testing

The third method of NDT this paper will discuss is Visual Testing (VT). Visual inspection techniques rely on the aided and/or un-aided eye for the purpose of inspecting a part or weld. VT is the most common testing method used across all industries as it is inherently part of all other test methods. VT may be aided by the use of a magnifying glass or un-aided using the naked eye and many defects are able to be located using VT including cracks, corrosion, misalignment of parts and discoloration.

VT can be performed with little or no equipment but still requires training in the analysis of findings and the use of proper procedures. VT’s limitations include only being able to detect surface breaking flaws and it is less sensitive to smaller flaws than other methods.

Even taking those limitations into account, as long as inspections are being performed, VT will be one of the most important tools an inspector can have in his arsenal.

Nondestructive Testing in a Manufacturing Environment

In any facility producing steel utility structures, NDT should be an integral part of nearly every stage of production. With the emphasis on cost efficiencies, lower quality steel, and high deposit welding consumables, quality control has the difficult task of keeping all the variables within tolerances. NDT is one of the key tools in ensuring that a quality product is received in the field by the end user.

UT is used to detect laminations in steel baseplates, to confirm weld penetration on long seams and is crucial for the confirmation of a complete joint penetration (CJP) weld. UT is required on 100% of structures with large T-Joint welds such as base plates and flanges for the detection of cracks both pre and post galvanizing.[2] Flaw detection in welding may be the single most important thing UT is used for and due to inconsistencies in training programs, many of those flaws are missed by improperly trained technicians.

MT and VT also aide in weld inspections - the identification of undercut, cold lap, crater cracks and poor starts/stops are just a few examples. Additionally, MT is often used during repairs to confirm that a crack is ground away prior to re-welding. In many cases multiple methods may be needed to validate an indication or increase the probability of detection for small indications.[3] This can be seen regularly with the use of visual testing to support all other forms of inspection.

Nondestructive Testing for In-Service Structures

NDT plays an integral role in the continued safe operation of in-service steel utility structures to determine if a structure is fit for continued service or needs to be repaired, strengthened or replaced. It is not uncommon to find a field technician using UT or MT inspection for the detection of fatigue in welds in the form of cracks. Often located at the top toe of the base plate to pole shaft weld on the bend lines of a multisided pole, what begins as a stress riser, over time, becomes a crack due to cyclic stress on the structure. In most cases, these toe cracks, cannot be seen by the naked eye and require some form of NDT to detect.

[2] ASCE/SEI 48-11 Design of Steel Transmission Pole Structures. 10.3.5 “Weld Inspection”
[3] “Verification of Indications” Bryan Lancon, ASNT Fall Conference and Quality Testing Show 2008

UT Transducer Gel Applied to A Weathering Steel Pole Prior to Testing to Identify the Extent of "Pack-out" Issues at the Slip Splice.

Internal and external corrosion can cause catastrophic problems to in-service utility structures up to and including failure. As seen above, left undetected and unchecked, corrosion can cause wall loss that often leads to a significant decrease in the structural capacity. Using UT inspection, a corrosion assessment can be completed giving an engineer the information needed to quantify the structural capacity of the effected pole. Without the use of NDT techniques, estimating a lifespan or plan of action for repair would be a shot in the dark.

Proper Training Is Key

Training programs in the NDT industry are numerous and varied and range in quality from very poor to excellent. ASNT has given us an excellent guideline utilizing SNT-TC-1A as a recommended written practice for the qualification and certification of personnel, but it is only a guideline and some employers choose to provide only the bare minimum to qualify technicians. It has been estimated that in some sectors the probability of detection is as low as 52% for a surface discontinuity with a length of .1".[4] Many variables that lower the detection rate can be eliminated with a high quality training program and a written practice following SNT-TC-1A or CP-189.

The process of qualifying technicians should be performed through formal classroom training with the recommended series of exams to prove knowledge and visual acuity. In some cases, employers train in-house through the use of a "Corporate Level III" and bad habits can be passed on.[5] A knowledgeable, properly certified educator using recognized course material is recommended and can prevent an internal "legacy" that utilizes those bad practices.

Following formal training, an apprentice technician needs quality on the job training meeting the minimum number of hours working under the direct supervision of a certified individual. Once the trainee has met

[4] "Probability of Detection", Materials Evaluation, Vol. 58, No. 4, April 2000.
[5] "Misconceptions within Magnetic Particle Inspection", George Hopman, ASNT Fall Conference 2007

the requirements of his company's written practice and proven his competency, the company can certify him in method.

Summary

As our countries infrastructure grows and ages, there will be an increased need for ongoing manufacturing quality control programs along with reliable monitoring and assessments of in-service steel utility structures. As that need grows, so too does the demand for well trained and certified individuals to perform nondestructive testing in the utility industry.

To ensure the continued safe operation of your structures and extend their lifespans, NDT should be an integral part of both you and your pole manufacturer's daily operations.

For further information, or questions, please contact:

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About the Presenter: Mr. Garrett Ehler

Mr. Ehler is a 1998 graduate of Baylor University in Waco, Texas with dual degrees in Environmental Science and Psychology. After spending several years in the heavy construction and utility industries, Mr. Ehler was one of the founding employees of ReliaPOLE Inspection Services Company, a Houston based inspection firm focused on the global pole and lattice tower industries. In 2015, Mr. Ehler and ReliaPOLE branched out to form Texas NDT Academy. As TXNDT's Senior Instructor and General Manager, Mr. Ehler is committed to providing his students with the ideal curriculum consisting of both the theories and science behind each course offered, but also their use in real world applications and best practices.

Certifications:

AWS CWI – 13071361
ASNT Level III – 229488 UT/MT
Level II PT
ACCP VT Level II – 229488
AGA Certified Inspector

To Drone, or Not to Drone? That will soon become the Question!

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ABSTRACT

It is common news that a cost effective alternative is emerging that may energize the inspection of this critical inspection activity. Small, unmanned aerial systems (sUAS) or “drones” as they are more popularly known, are available that can now gather very detailed photographic and other sensory data from virtually any position above, and around an electrical transmission structure or substation. All the while, the “pilot” or operator remains safely on the ground. This can be done while the high voltage transmission lines remain fully energized. The question will soon become, does my Utility need in-house capability for this technology? In this presentation we will review the current “state of the art” with respect to “drone” technology as well as the current “state of affairs” with regard to the various state and federal regulatory (FAA) issues facing those wishing to employ this new “drone” technology.

ACRONYMs

UAV – Unmanned Aerial Vehicle

UAS – Unmanned Aerial System (FAA)

sUAS – Small Unmanned Aerial System (FAA < 55 lbs)

RPAS – Remotely Piloted Aircraft System (European)

Drone – Common nickname originating w/military craft

The original application for unmanned aerial vehicles or “drones”,

But this is my favorite use of “drone” technology

Currently, we are an FAA approved company using “Drones” for:
High Definition Imaging & Multi-Spectral structural assessment of
High Voltage Electrical Transmission Lines;
Telecommunications Towers;
Wind Towers & Blades.

sUAS System Considerations

What are the needs for:

1. Aircraft type (fixed wing or multirotor)?
2. Sensor / payloads?
3. Ground control station?
4. Communication systems requirements?
5. Pilot and crew requirements?
6. Knowledge of FAA Regulations?
7. Knowing Safety issues?
8. Mitigation of Operational Risks?
9. Acknowledging PRIVACY risks?
10. Understanding Security Risks?

We use a Falcon 8 Multi-rotor sUAS
Developed by Ascending Technologies GmbH (Germany)

Features of the Falcon 8:

Multi-rotor (for enhanced power, stability, and redundancy)

Triple redundant flight control
(signaling connections with mobile ground station)

GPS assisted flight including lost signal Return to Home

Gimbal stabilization (of camera or other sensor images)

HD Streaming Video or Photography

FPV (first person view) Capable

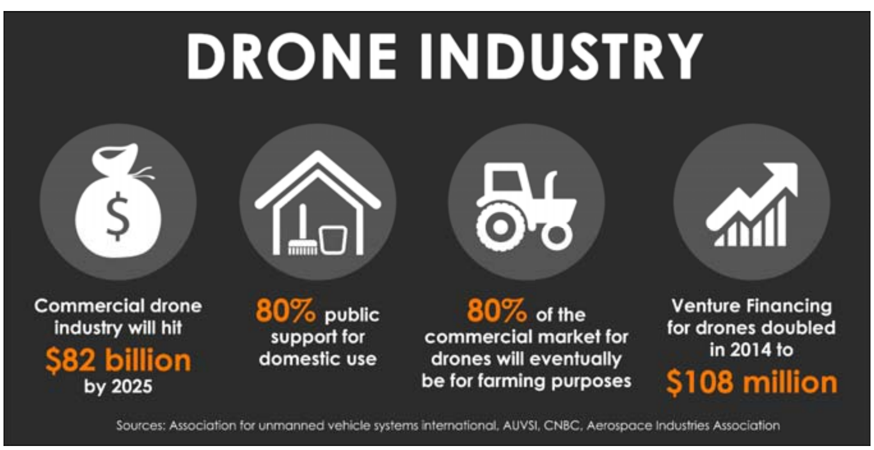
Independent Camera Operation (essential for detailed inspection)

180 degree Camera tilt angle (straight up or straight down)

Capable of "Autonomous" pre-programmed flights

Professional grade systems: Multi-Rotor

Professional Grade Systems: Single Rotor/Fixed Wing



Current Exemptions Granted by FAA

n= 835 Exemptions Granted*

- 90 Precision Agriculture
- 241 Industrial Inspections (Incl. several dozen Electric Utilities)
- 418 Movie/Photography
- 138 Mapping/Surveying
- 42 Public Safety
- 25 Others

* Some exemptions granted allow multiple uses.

SO WHAT VALUE CAN DRONE TECHNOLOGY BRING TO THE ELECTRIC UTILITY INDUSTRY?

Do you need a **BIG tool**, when a **LITTLE tool** will work????

Fact:

Working around High Voltage Substations & Lines is Dangerous work!

Bottom Line Questions are:

Can the work be done more safely with UAS's?

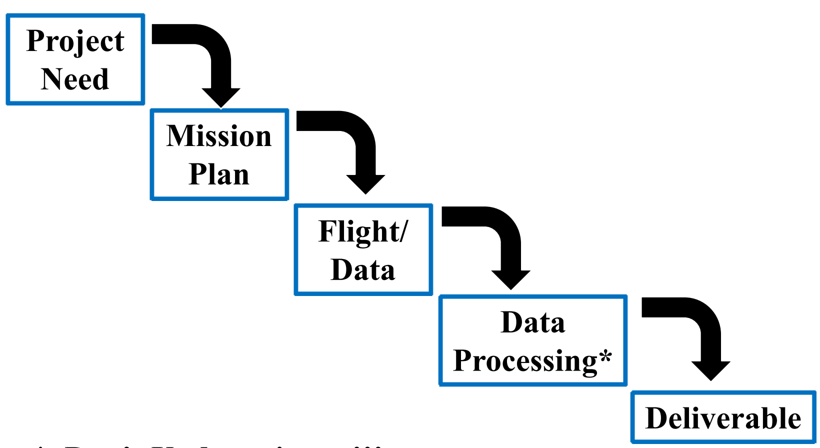
Can the work be done more efficiently with UAS's?

Can the work be done more cost effectively with UASs?

YES, YES, & YES!

But,

Understand the work flows!

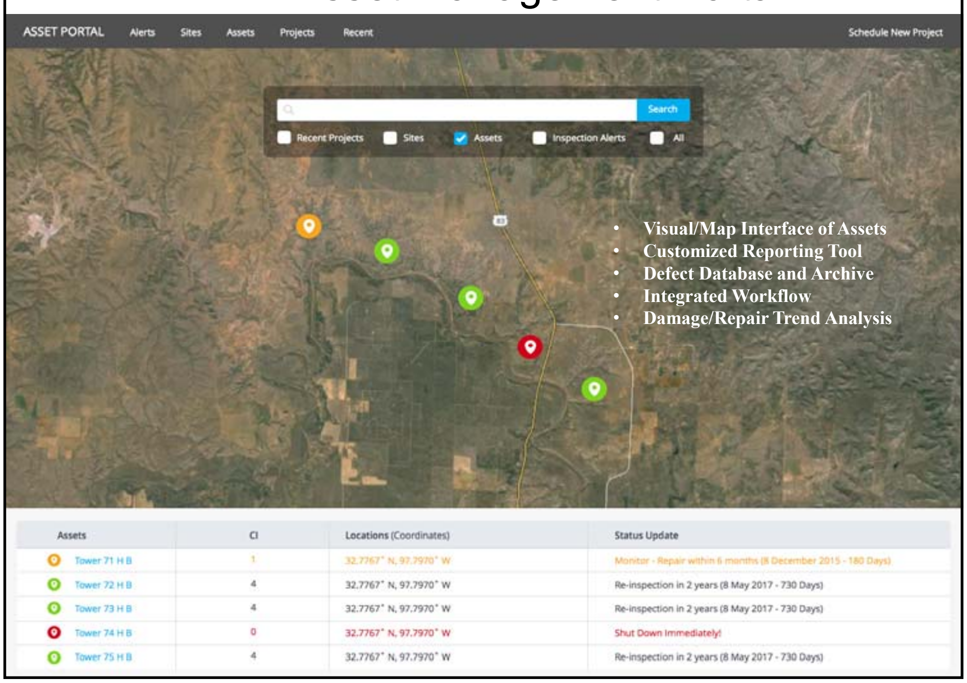


* Don't Underestimate!!!

UAS's

Need for Big Data Management Capability

AAIR Asset Management Portal



EPRI Line Patrol Research

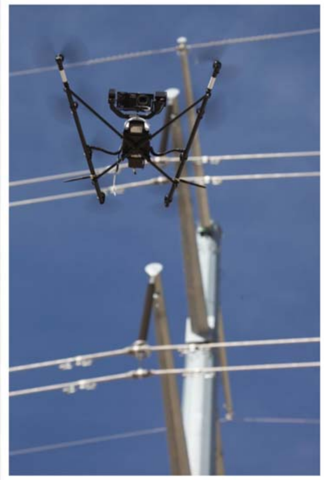
Steel Tower Line-% Of Defects Reported

Aerial Patrol	0.4%
Ground Patrol	17.1%
Climbing Patrol	29.3%
Detailed Aerial	47.6%

Wood Pole H-Frame-% Of Defects Reported

Aerial Patrol	1.7%
Ground Patrol	12.8%
Climbing Patrol	15.6%
Detailed Aerial	36.3%

Research project included:
100 Lattice Towers and 100 Wood Pole H-Frames

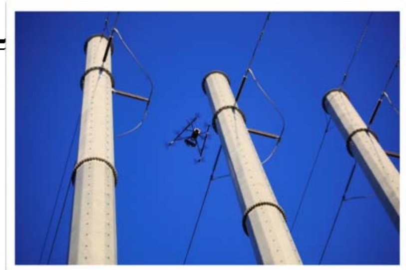


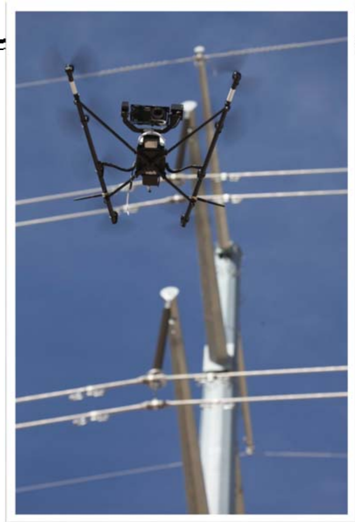
Visual Inspections:

of New Lines & Existing Lines:

- **Weld Quality**
- **Weld Cracking**
- **Corrosion**
- **Arm Connections**
- **Conductors/Insulators**
- **Attachments**
- **Missing bolts/members**

All UAS inspections can be accomplished on ENERGIZED Lines while the "pilot" and camera operator remain safely on the ground. No Outages required!





Critical UAS Features for Utility Line Inspections

- “Hardened” flight control systems.
- Dual axis 180 degree field of vision vertically and craft can be pivoted 360 degrees horizontally.
- High Definition Digital Camera
  (36 megapixels or greater is available)
- Stabilized camera mount & flight control for crystal clear imagery
- GPS guidance system (includes GPS “hold” and Return to Home features)
- Can be flown in winds up to 30 mph
- Deployable in minutes with:
  Entire system weighs under 5 lbs

- High resolution digital camera payload
- Real time video stream to mobile ground station
- High storage capacity for images (can be geo-tagged with flight data)
- Remotely operated from a mobile ground station. Independent camera controls
- Camera operator can use FPV goggles to better determine points of interest

Observed cracked weld 140 ft in the air.

Missing bolt on flange plates (approximately 100ft in the air).

Separated grounding wire (approximately 90ft in the air).

Open gaps between flange plates

New Construction – Conductor Attachment Hardware

New Construction – Static/OPGW Attachment Hardware

Checking for damage on conductor

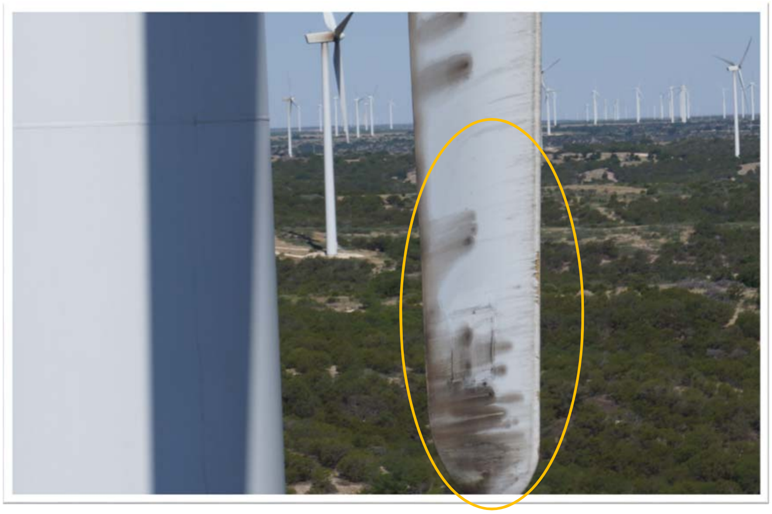
Use of sUAS's for other than Visual Inspections

- Lidar (Mapping/GIS)
- Thermal Imaging (FLIR)
- UV Imaging
- Corona Detection
- Video Survey
- Storm Damage Assessment

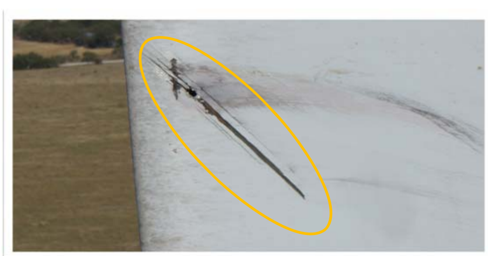
Right of Way Inspection
(New Line & Existing Line)

- Survey
- Encroachments
- Security

Wind Towers/Blades



Wind Towers/Blades



Regulatory & Political Issues

Regulatory Issues – National Airspace Safety

- FAA believes existing regulations prohibits commercial use of UAS!
- Formal rules and additional regulations are being developed (likely enacted next year).
- FAA is currently issuing "Section 333" Exemptions to current regulations on a case by case basis (approximately 700 issued so far)

Typical Section 333 Exemption Requirements:

- Exemption limited to a specific make and model UAS system.
- Monthly Reporting of all UAS Flight Activity to FAA
- Blanket COA's limit height to 200'
- Project specific COA's can extend height to 400'
- File a Notice to Airmen (NOTAM) for all flights
- Must fly Visual Line of Sight (VLOS) – No autonomous flights yet approved.

Typical Section 333 Exemption Requirements:

- Pilot in Command must hold a current pilot's license issued by the FAA (minimum sports pilot license).
- Must have an "Observer" on the flight team independently monitoring any local air traffic.
- Our crews utilize an independent camera operator so that is written into our COA as well.
- Must have various flight operations and maintenance manuals on file with the FAA.

In Summary:

- Drones are a very **cool technology**
- The are **safe** and **effective!**

Drones are going to become an absolutely essential tool for transmission, distribution, and substation engineers/constructors/ inspectors in the very near Future!

Thank you for your attention!
Any Questions?

My Contact Information for further information is:

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VACUUM INTERRUPTERS: PRESSURE VS. AGE
A Study of Vacuum Levels in 314 Service Age Vacuum Breakers

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Abstract

All vacuum interrupters (VIs) increase in internal pressure over time. [Authors' note: In this paper the modern term *vacuum interrupter* will be used in lieu of the now obsolete *vacuum bottle*.] The pressure increase may be due to small, long-path leaks from outside to inside, diffusion through the container materials and/or virtual leaks from materials within the internal volume. VI manufacturers design and test their vacuum interrupters for a minimum lifetime of twenty to thirty years. VIs may successfully operate beyond this period but it is beyond their design life.

Since the first large influx of vacuum interruption in the early 1970s, the technology has become the most widely applied power interruption technique in the medium voltage range (2.4kV - 38kV). Vacuum technology now dominates the interrupter market throughout the world. This means that there are hundreds of thousands of VI breakers and contactors in field that were manufactured twenty or more years ago. Inevitably, in-service VI failures caused by vacuum loss have greatly increased over the last ten years.

Until recently there was no technology that allowed field testing vacuum levels in VIs. Using a field portable magnetron, test technicians can now test vacuum level and thereby evaluate the VI condition based on that parameter. The vacuum level test is called the Magnetron Atmospheric Condition (MAC) test.

To further knowledge in this area, the authors have performed vacuum level tests on 314 circuit breakers (809 VIs). The VIs being tested were installed in breakers that had manufacturing dates ranging from 1978 through 2014. It is assumed that the VIs were manufactured at the same time as the breakers. The results of these tests have been evaluated. This paper describes the data gathering methodology, shows the analysis that was done, and presents the results of that analysis.

Introduction

Vacuum Level vs. Interrupting Rating

From Paschen's Law (Louis Karl Heinrich Friedrich Paschen 1865-1947) we know that the dielectric strength between two electrodes is a function of the pressure of the gas between them.

Figure 1 shows Paschen's Law applied to dry air in a volume containing electrodes at spacings typical of those in a vacuum interrupter. The horizontal axis is the air pressure in Pascals (Pa), and the vertical axis is the dielectric strength in kilovolts per centimeter of electrode separation.

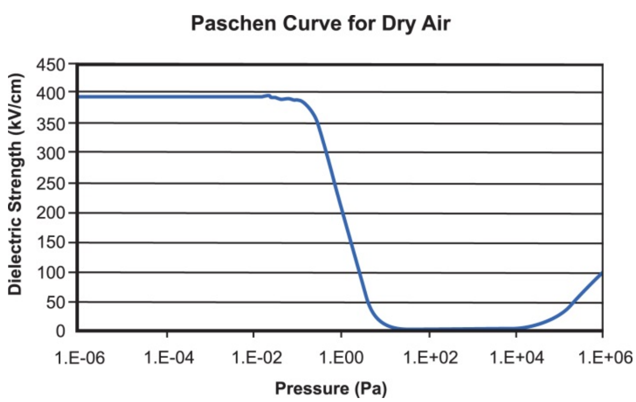


Figure 1: Paschen Curve for Dry Air

As the pressure in the interrupter is decreased from one atmosphere (≈$1x10^5$ Pa) the dielectric strength first drops to a very low level. Then, at around 10 Pa the dielectric strength starts to rise. At 10^{-1} Pa the dielectric strength has reached slightly less than 400 kV/cm and remains constant for all lower pressures.

Although manufacturer design specifications vary slightly, most newly made VIs have internal pressures in the range of 10^{-4} Pa to 10^{-7} Pa; however, all VIs leak to some degree, and as the pressure rises the dielectric strength will decrease when the pressure exceeds 10^{-1} Pa.

Leaks in a Vacuum Interrupter

The internal pressure of a vacuum interrupter can be increased by three main causes: gas permeation, virtual leaks, and real leaks.

Gas permeation is the infiltration of gases into the vacuum interrupter volume through the insulation material and metallic surfaces by diffusion. Only very small molecules, such as hydrogen (H_2) or helium (He), can diffuse through these materials. The upper limit of the internal pressure that can be attained by diffusion is in the range of 10^{-2} Pa. [1] To help control the pressure increase from these leaks, a *getter* material is normally mounted inside the vacuum interrupter which provides a continuous pumping for low levels of H_2, N_2, O_2, and other various residual gases. [2] This getter material is activated by high temperatures during the final stages of the vacuum interrupter manufacturing process and will function until the getter surface has been saturated with gas molecules. Note that the getter is ineffective at pumping inert gases such as helium or argon.

Virtual leaks are the results of outgassing from internal surfaces and parts as well as diffusion of gases from "trapped" volumes (from poor brazes or welds) to the main VI volume. Research performed on one type of vacuum interrupter in 1978 showed that "gas evolved from the bulk of the material was the major contributor to pressure buildup." [3] Improved manufacturing techniques have significantly reduced this type of leak by selecting well-refined, low gas content materials and by fully degassing parts in the production process of the vacuum interrupter. [4]

Real leaks are gases penetrating the interior of the vacuum interrupter through microscopic paths caused by manufacturing defects, mechanical damage, corrosion, and/or external flashover. With the exception of corrosion, the rate of internal pressure increase caused by real leaks is much greater that leaks caused by gas permeation and virtual leaks. Most real leaks cause failure due to inadequate vacuum in a short period of time. Corrosion can result in a slower leak which can take as long as a year to compromise the integrity of the vacuum. [1]

As vacuum interrupters age, a combination of the described factors cause an increase in internal pressure and, depending on the environmental, circuit, and mechanical conditions, may increase faster or slower for a given vacuum interrupter.

Testing Vacuum Level

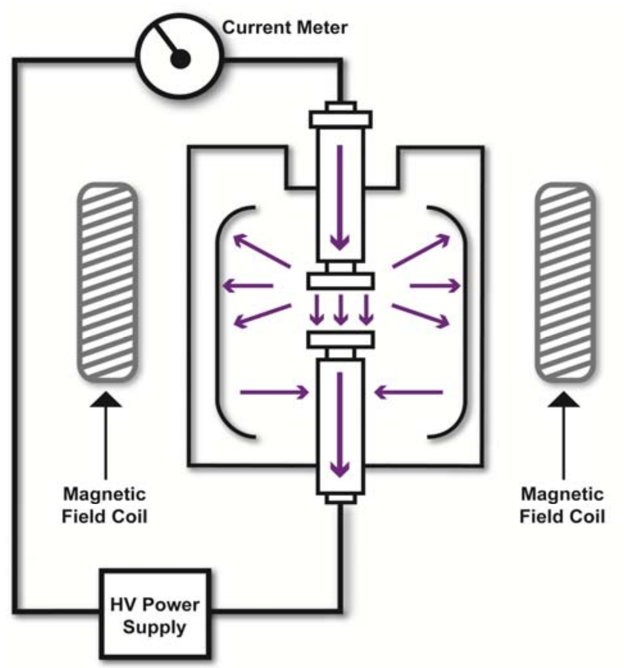


Figure 2: Penning Discharge Test

Determining the pressure in an enclosed, sealed chamber is done using a test based on the

Penning Discharge Principle. (Frans Michael Penning 1894-1953) Penning showed that when a high voltage is applied to open contacts in a gas and the contact structure is surrounded with a magnetic field, the amount of current flow between the plates is a function of the gas pressure, the applied voltage, and the magnetic field strength. Figure 2 is a diagram of the test.

A magnetic field is set up by placing the VI into a field coil. The field is created by a direct current and remains constant during the test. A constant DC voltage, usually 10 kV, is applied to the open contacts and the current flow through the VI is measured.

Since the magnetic field (DC) and the applied voltage (DC) are both known, the only variable remaining is the pressure of the gas. If the relationship between the gas pressure and the current flow is known, the internal pressure can be calculated based on the amount of current flow.

The test equipment used to perform this procedure is called a *magnetron*. Until recently, the magnetron was a very bulky and difficult to use in the field. It was, therefore, relegated to manufacturer laboratory testing.

In recent years, more portable equipment has become available and the vacuum level can be readily tested in the field. Figure 3 shows such a test set up.

Figure 3: VI Vacuum Test (MAC Test)

Objectives

As the data collection and testing progressed it became clear that we had five basic objectives in mind:

1. What, if any, correlation exists between the VI age and its internal pressure.
2. What, if any, correlation exists between the VI age and its AC HiPot test results.
3. What, if any, correlation exists between the VI age and its contact resistance.
4. What, if any, correlation exists between the VI vacuum level and the AC HiPot results.
5. Do the AC HiPot test results have any predictive value as far as the VI serviceability is concerned or is the AC HiPot strictly a go no-go test?

Experimental Methodology

Test Population

The 314 circuit breakers were all the same model and from the same manufacturer but included a range of ratings and VI types. All of the breakers had been in actual service at some point in their history. None of the breakers or interrupters had been modified from the manufacturer's original specifications.

One manufacturer was used to eliminate any statistical differences that might occur due to different manufacturing methods. Future tests will be performed on other manufacturers and the differences, if any, will be noted.

Test Procedure

1. Document the breakers and all components visually using digital photography. Note any differences and classify pinch tubes if present.
2. Record all nameplate information. Take high resolution digital photos.
3. Thoroughly clean all dust and contaminants from the breaker
4. Check primary contact erosion
5. Perform contact resistance tests
6. Perform MAC Test

7. Perform AC High Potential Test and measure/record leakage current at the recommended test voltage.

Collected Data

Nameplate data collected for all circuit breakers includes manufacturer, breaker type, serial number, rated max voltage, impulse voltage, rated amps, cycles, hertz, rated voltage range, close and latch compatibility, date of manufacture, close coil details, trip coil details, connection diagram, mechanism type, vacuum interrupter type, phase serial numbers, phase pinch tube details, and weight.

Inspection data collected includes the breaker mechanical operations before and after testing, ambient temperature, humidity, and the technician ID.

Test data collected for each of the three phases includes the MAC Ion Current, Contact Gap, Contact Resistance, AC HiPot Test (pass/not pass and the leakage current), and Contact Time Open and Close results.

Ten percent of the tested population (84 out of 809) exceeded the maximum pressure measurable with the MAC tester (~5 x 10E-1 Pa – high pressure). These units were not included in the analysis since our analysis method requires continuously variable data.

The percentage of VIs with high pressure increases with VI age as illustrated below:

Age (Years)	High Pressure	Measurable Pressure
1 – 10	4%	96%
11 – 20	3%	97%
21 – 30	7%	93%
> **30**	20%	80%

Table 1: VI Percentage of High Pressure Increases by Age

Data Analysis

Correlation of Data Sets

The correlation coefficient (r) measures the direction and strength of the linear relationship between two quantitative variables. It is computed as follows:

$$r = \frac{1}{n-1}\sum_{i=1}^{n}\left(\frac{x_i - \bar{x}}{s_x}\right)\left(\frac{y_i - \bar{y}}{s_y}\right)$$

Where:
r is the correlation coefficient
n is the sample size
x and y are the independent and dependent variables respectively
$\bar{x}$ and $\bar{y}$ are the means of x and y
s_x and s_y are the standard deviations of x and y

Due to the small sample size, we performed an additional calculation to offset any bias, seen here:

$$r_{adj} = r[1 + \frac{1 - r^2}{2(n-1)}]$$

Where:
r_{adj} is an unbiased estimator of r.
Note that for large values of n, $r_{adj} \approx r$. [5]

Properties

- For $r > 0$, there is a positive relationship between x and y; that is, when x increases, y increases. For $r < 0$ there is a negative relationship between x and y; that is, when x increases, y decreases.
- Correlation is always a number between -1 and 1. Values near -1 or 1 indicate a strong relationship and values near 0 indicate a weak relationship.
- The square of the correlation coefficient, r^2, is the fraction of the y values whose variance can be explained by a change in x.
- As with mean and standard deviation, r is heavily influenced by outliers.

Discussion of Results

A Magnetron Atmospheric Condition test (MAC) was performed on 809 vacuum interrupters of varying age to determine the internal pressure. The MAC test measures the current generated by ionized gas molecules inside the vacuum interrupter and converts this value to a pressure using formulas (curves) based on experimental data. A set of curves was produced to maintain a high degree of accuracy when testing VI's of different diameters. Vacuum interrupter manufacturers use the same procedure when performing quality control tests on new vacuum interrupters. For the calculations, a normalized MAC Pressure result in Pascals was used. Of those 809 vacuum interrupters, 758 were also given a High Potential test for comparison.

Data Distributions

Figures 4 through 7 are scatter plots of the various comparisons performed in the analysis of the VI data. Correlation coefficients were calculated for each of the data sets that are shown with the curve fits most commonly found in nature, including linear, logarithmic, exponential, square, and square root distributions. Each graph has a note indicating the best fit distribution.

Divisions within Data

To ensure a homogeneous data set, the correlation coefficients of MAC Pressure values and the age of the vacuum interrupters for the entire sample and for subgroups designated by VI Type, MVA, Mechanism Type, and Pinch Tubes were computed. None of these divisions had a significant impact on the strength of the relationships. All results are for the VI sample as a whole.

Relationships

In addition to the MAC Pressure and VI age relationship, correlation coefficients were calculated for AC HiPot results versus VI age, Contact Resistance versus VI age, and MAC Pressure versus AC HiPot results.

Distribution	*x* Variable	*y* Variable	r	r_{adj}	r^2
Exponential	Age	MAC Pressure	0.4105	0.4107	16.87%
Exponential	Age	AC HiPot	0.1194	0.1195	1.43%
Exponential	Age	Contact Resistance	0.3171	0.3173	10.07%
Linear	MAC Pressure	AC HiPot	-0.0362	-0.0362	0.13%

Table 2: Correlation Coefficient Calculations

The strongest relationship was found to be age of the VI versus the MAC Pressure values, with an unbiased exponential correlation coefficient (r_{adj}) of 0.4107. This is a much stronger relationship than the 0.1195 r_{adj} value for AC HiPot test results versus VI age. As more time-related data becomes available we expect the individual VI curves will more closely follow the exponential change. This will lead to larger correlation coefficients.

MAC Pressure and Age

In Figure 4, there is an exponential rise in pressure values over time. The increased spread in pressure values for the older VIs is expected. We believe additional tests over time of the same sample VIs will reinforce the relationship between MAC Pressure results and age. This would remove much of the variance caused by both environmental and internal variables.

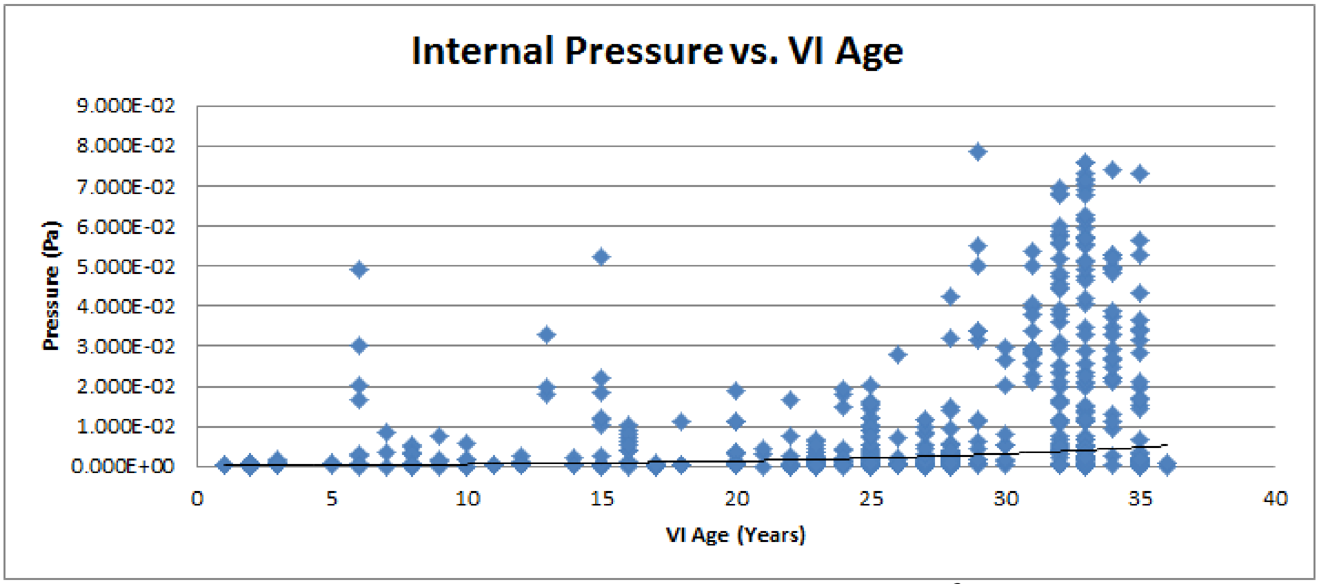


Figure 4. Exponential Distribution of Internal Pressure vs. VI Age where r_{adj} = 0.4107 and r^2 = 16.87%

AC HiPot and Age

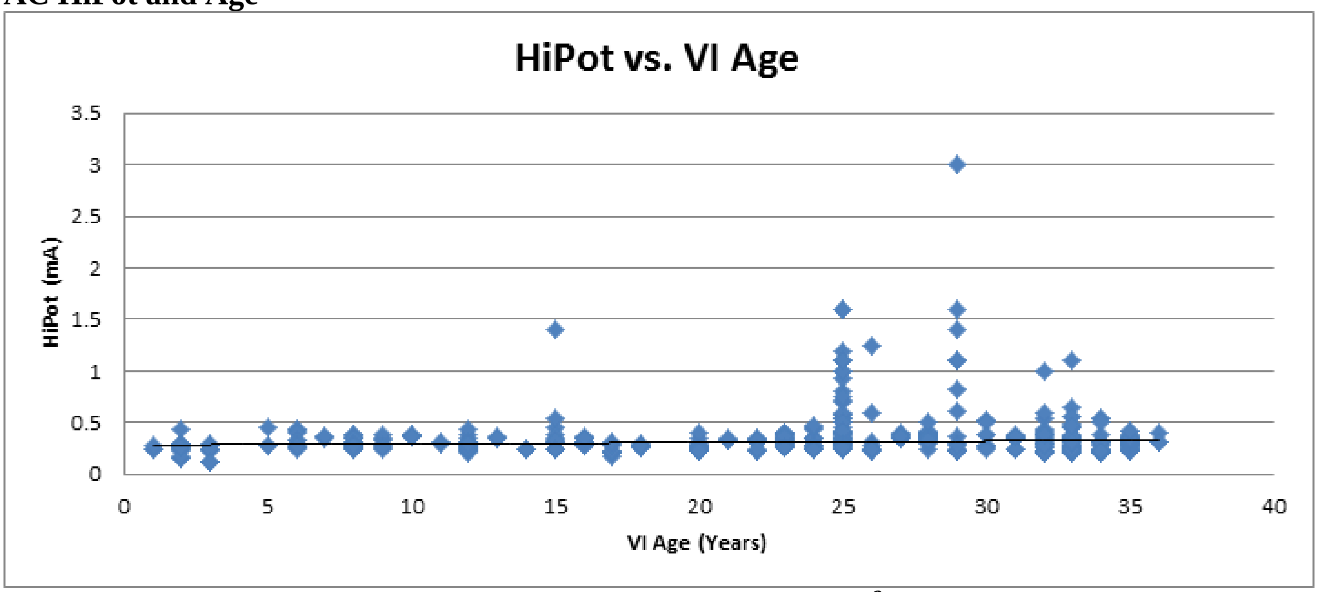


Figure 5. Exponential Distribution of AC HiPot vs. VI Age where r_{adj} = 0.1195 and r^2 = 1.43%

Contact Resistance and Age

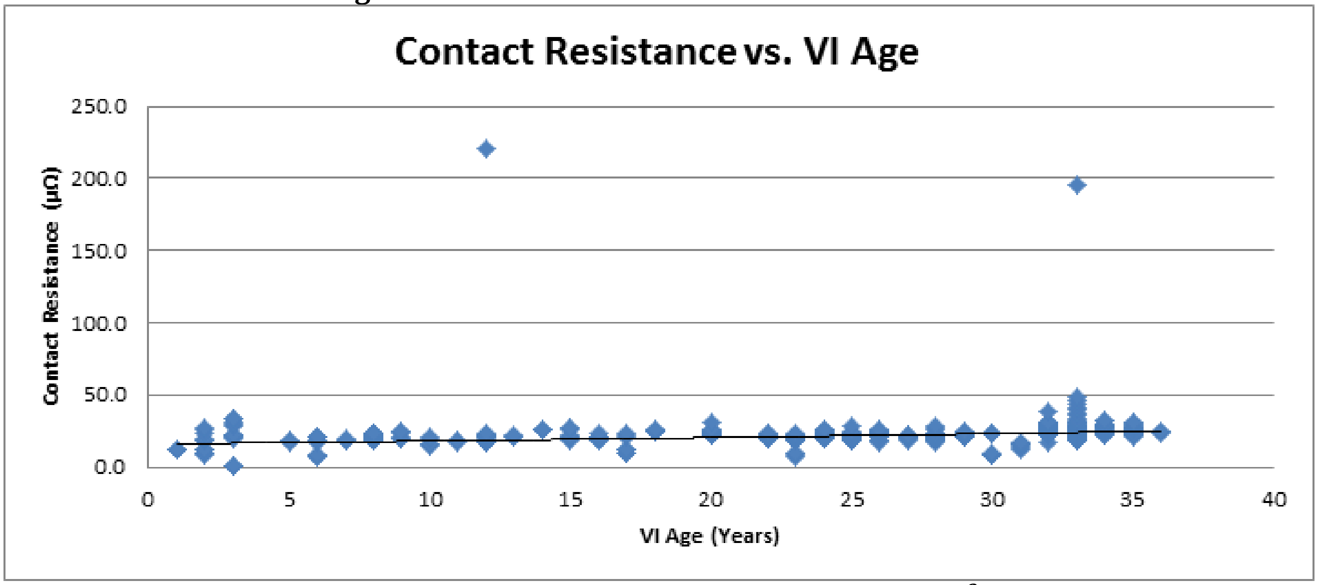


Figure 6. Exponential Distribution of Contact Resistance vs. VI Age where r_{adj} = 0.3173 and r^2 = 10.07%

MAC Pressure and AC HiPot

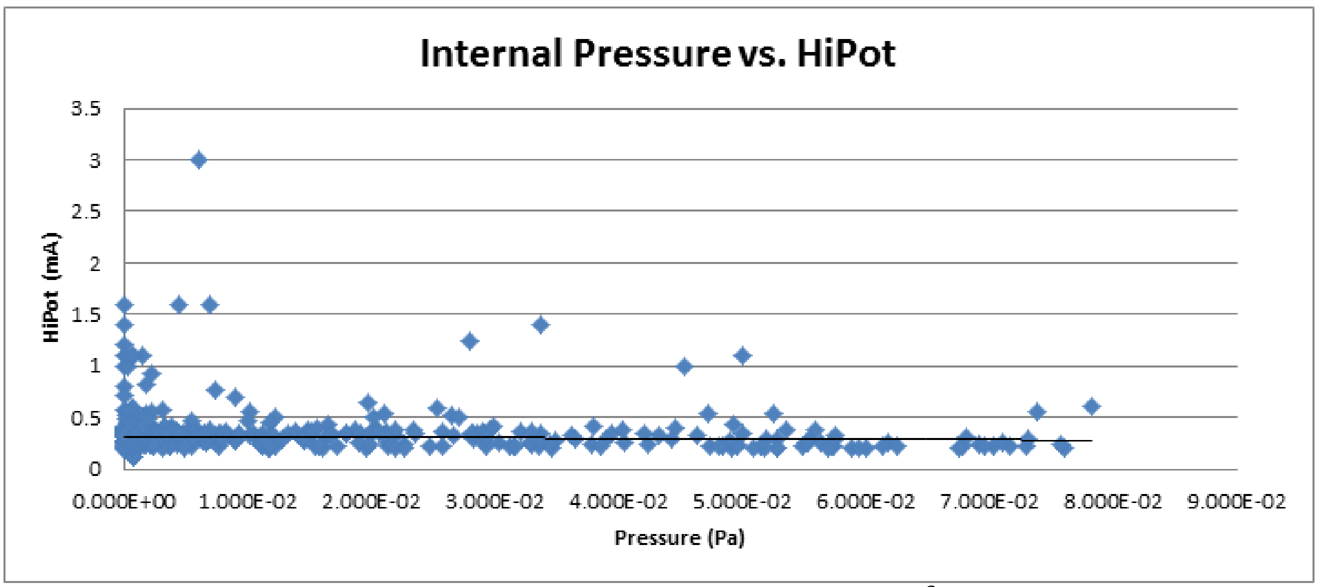


Figure 7. Linear Distribution of Internal Pressure vs. AC HiPot where r_{adj} = -0.0362 and r^2 = 0.13%

Summary and Conclusions

Summary

Tests were performed on 809 service-aged vacuum interrupters from the same manufacturer, of similar design, and of similar type with a range of age from 1978 to 2012. The tests performed were the contact resistance, ac high-potential test, and MAC tests. After the data was compiled correlation calculations were made for the following:

- VI age versus VI pressure
- VI age versus ac resistance (HiPot)
- VI age versus contact resistance
- VI pressure versus ac resistance

Three variables were not factored into the final calculations.

Numbers of Operations: The numbers of operations were captured in the dataset and preliminary correlation calculations were made against the other variables. Based on these results it was decided not to factor numbers of operations into this study.

In-Service Ambient Conditions: There was no way to qualitatively or quantitatively include variations of in-service ambient conditions. It is possible, though by no means certain, that wide in-service temperature extremes could increase the VI leakage rate. This is being looked at and considered for a future iteration of this research.

Time-Related Data for Individual VIs: No data was available for individual VIs with respect to time prior to the present study. Our Condition Based Maintenance research has shown that inclusion of individual time-based data greatly improves the quality of the statistical analysis. We have isolated ten of the breakers from the present study to be fully reevaluated in a five year period. This will help to establish important leak rate information for the VIs being tested and provide a means for projecting failure due to internal pressure rise.

Conclusions

We have drawn the following conclusions from our research:

1) There is a relatively close correlation between VI age and internal pressure. We believe that this correlation will be strengthened by an increase in the size of the database and inclusion of time-related data for individual breakers.
2) The high pressure VIs not included in this analysis support this exponential relationship (see the Collected Data section).
3) There is a small to moderate correlation between the contact resistance and VI age.
4) There is a minimal correlation between AC HiPot test and VI age.
5) There is an insignificant correlation between AC HiPot leakage current results and internal pressure.

Given the proven relationship between dielectric strength (interrupting ability) and vacuum level, we are confident in offering the following conclusions:

1) The MAC test (VI internal pressure) provides excellent predictive data for determining VI continuing serviceability. The MAC test should be considered as an important tool in the breaker maintenance tool bag.
2) Contact resistance testing may provide some value as a predictive tool; however, there are two significant issues that must be accounted for.
   a) Frequent contact erosion adjustments must be accounted for. For example, the interrupter contact pressure can change with wear/interruption history.
   b) The significant differences in contact area (a 400 ampere VI versus a 3000 ampere VI) must be accounted for.
3) Since there is virtually no correlation between AC HiPot leakage current and VI age or vacuum level, the high-potential test is of no value in any predictive maintenance program for the VI. We recommend using the AC HiPot test for evaluating the current functioning of the VI as well as the other insulation systems in the breaker. However, the addition of the MAC test will provide a means of actually estimating the remaining vacuum life of the VI and is a valuable tool in selecting which VIs are due for replacement.

Appendices

1. Glossary
   a. *Getter*: A deposit of reactive material that is placed inside a vacuum system for the purpose of achieving and maintaining operating vacuum levels.

b. *Vacuum Interrupter*: A current interruption device in which the interrupting contacts are enclosed in a vacuum.
c. *Vacuum Bottle*: Vacuum Bottle is an obsolete term for vacuum interrupter. (See Vacuum Interrupter)

2. References

[1] Renz, R., Gentsch, D., Slade, P. et al. (2007) Vacuum Interrupters – Sealed for Life. 19th Int. Conf. of Electr. Distr. (CIRED), 21-24 May, Paper 0156

[2] Slade, Paul G. *The Vacuum Interrupter: Theory, Design, and Application*. Boca Raton: CRC Press, 2008

[3] Arthur, M.E.; Zunick, M.J., "Useful Life of Vacuum Interrupters," *Power Apparatus and Systems, IEEE Transactions on*, vol.PAS-97, no.1, pp.1, 7, Jan. 1978

[4] Okawa, M.; Tsutsumi, T.; Aiyoshi, T., "Reliability and Field Experience of Vacuum Interrupters," *Power Delivery, IEEE Transactions on*, vol.2, no.3, pp.799, 804, July 1987

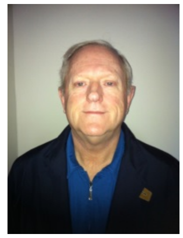
[5] Moore, David S., McCabe, George P., *Introduction to the Practice of Statistics*, Fourth Edition, W.H. Freeman and Company, New York, 2003

3. Author Bios

John Cadick, P.E.

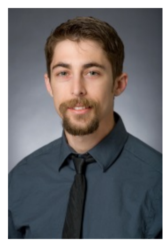
A registered professional engineer, John Cadick has specialized for over four decades in electrical engineering, electrical safety, training, and management. In 1986 he founded Cadick Professional Services (forerunner to the present-day Cadick Corporation), a consulting firm in Garland, Texas. His firm specializes in electrical engineering, marine services and training, working extensively in the areas of power system design and engineering studies, condition based maintenance programs, and electrical safety. Prior to the creation of Cadick Corporation, John held a number of technical and managerial positions with electric utilities, electrical testing firms, and consulting firms. Mr. Cadick is a widely published author of numerous articles and technical papers. He is the author of the Electrical Safety Handbook as well as Cables and Wiring. His expertise in electrical engineering as well as electrical maintenance and testing coupled with his extensive experience in the electrical power industry makes Mr. Cadick a highly respected and sought after consultant in the industry.

Finley Ledbetter



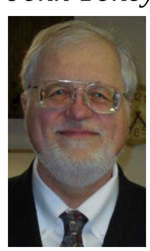
Finley Ledbetter is the Chief Scientist for Group CBS Inc. with over thirty-five years of power systems engineering experience a member of the IEEE and past president of PEARL.

Jerod Day



Jerod Day received his B.S. and M.S. degrees in Mechanical & Energy Engineering in 2010 and 2012, respectively, from the University of North Texas, Denton, TX. Jerod has coauthored publications including the J. Heat Transfer. He is the Vice President of Vacuum Interrupters, Inc. in Carrollton, TX which specializes in vacuum interrupter design and testing. Mr. Day has five years of field experience with medium voltage circuit breakers and switchgear.

John Toney



John Toney, trained as an electrical engineer, has specialized for over thirty years in the design, development, testing and manufacture of vacuum interrupters / vacuum circuit breakers. Currently he is a design engineer for Vacuum Interrupters Inc. His undergraduate degrees are from University of Michigan – Ann Arbor (BS in Astronomy and BSEE) and his master’s degree is from Drexel University – Philadelphia (MSEE).

Finley Ledbetter III

Finley Ledbetter III Received his B.S. degree in Electrical Engineering from The Texas Tech University in 2011. He has worked for three years at Western Electrical Services as a field service engineer earning his NETA Level II Assistant Technician certification and more recently as product manager for the Instrument group a Vacuum Interrupters Inc. Finley's responsibilities include developing new technology for Group CBS and performing field testing and demonstrations. Finley has the distinction of performing more field MAC tests than any other engineer or technician.

Gabrielle Garonzik

Gabrielle Garonzik holds a bachelor's degree in Actuarial Sciences from the University of Texas. She signed on with Cadick Corporation in 2005 developing CBM 2010, a predictive maintenance algorithm for electrical equipment. She is currently the Director of Research and Development for Cadick Corporation.

WHEN TO STRESS OVER CONDUCTOR STRAINS

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TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM 2015
Dallas, Texas

INTRODUCTION

Recent project work and industry trends in stress-strain modeling approaches to overhead line conductors highlights the variety in conductor stress-strain behavior. Historically, the variety has been understood and accommodated in line design efforts as a result of known inaccuracies in the design process. With the invent and application of detailed overhead line design softwares combined with the designer's possible misunderstanding of the accuracy of the stress-strain models themselves results in unreasonable expectations on the accuracies of our sag-tension analysis.

It's important to note that when considering the accuracy of one conductor model to another, each model of the conductor's stress-strain behavior is simply one of many possible descriptions of each production set, reel, and length of conductor. Another round of testing will likely produce a stress-strain model which is slightly different from the models assessed in this study. For this reason, it's very difficult to assign validity of one model over the other and apply as the true description of stress and strain behavior for each and every span and section in a design effort. One must expect variances.

STRESS-STRAIN CURVES

Design in the USA commonly applies the Experimental Plastic Elongation Stress-Strain Model. Overhead conductors are modeled as non-linear springs that elongate elastically as a function of tension, plastically as a function of tension and time, and thermally as a function of temperature. For non-homogeneous conductors, the elongation of each component (e.g. steel and aluminum) is calculated separately.

Plastic elongation of the conductor due to "settling", "creep elongation", and "plastic elongation (due to high tension loads)" is calculated for an assumed series of loading events over the life of the line.

Stress-strain measurements are typically done per The Aluminum Association's documents "A Method of Stress-Strain Testing of Aluminum conductor and ACSR" and "A Test Method for Determining the Long Time Tensile Creep of Aluminum Cables in Overhead Lines". The former measures the short-term (elastic) behavior of the conductor under varying loads. The latter measures the long-term behavior (creep) under one specified load assumed to represent the average tension of the conductor (typically an everyday condition).

In the initial S-S test, approximately 15 m of new conductor is placed in a tensile bed test machine. After an initial bias tension (typically the smaller of 1000 lbs or 8% RBS), the tension is incrementally increased and held (30% RBS for 30 minutes then 50%, and 70% RBS for an hour each). At the end of the hold, the strain is measured and plotted. A best-fit polynomial is applied to the data points, and this is known as the one hour modulus for the composite conductor (see Figure 1).

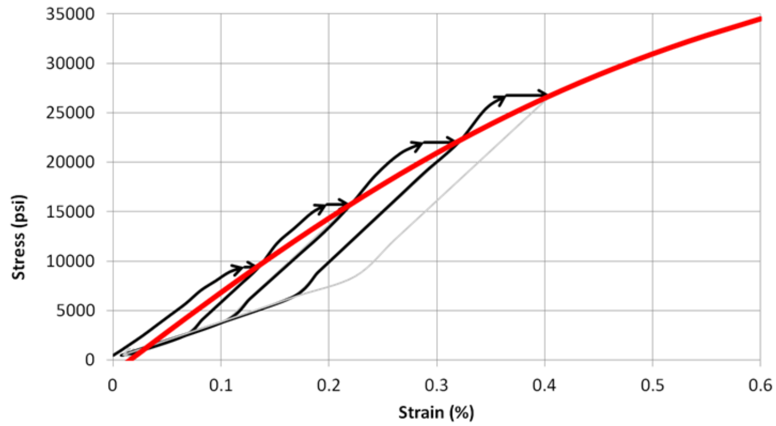

Figure 1: Elastic Stress-Strain Curve

With all aluminum conductors, this is the only initial stress-strain test required. For non-homogeneous conductors (ACSR, ACSS, etc), the test is initially performed to predict the stress-strain behavior of the core. These values are then subtracted from the composite stress-strain model to predict the initial S-S characteristics for the outer aluminum strands.

Creep is a metallurgical phenomenon wherein metallic elements under tensile loads elongate with time, even at stresses below the yield stress. Creep behavior is measured by subjecting a piece of new conductor to a constant pre-determined load for 1000 hours (~42 days) under controlled temperature. The percent strain is measured during this time and plotted on a log-log curve (See Figure 2) and the curve is extrapolated to 100,000 hours. When this log-log plot is converted to a standard axis plot (strain vs time), it generates the familiar non-linear creep curve.

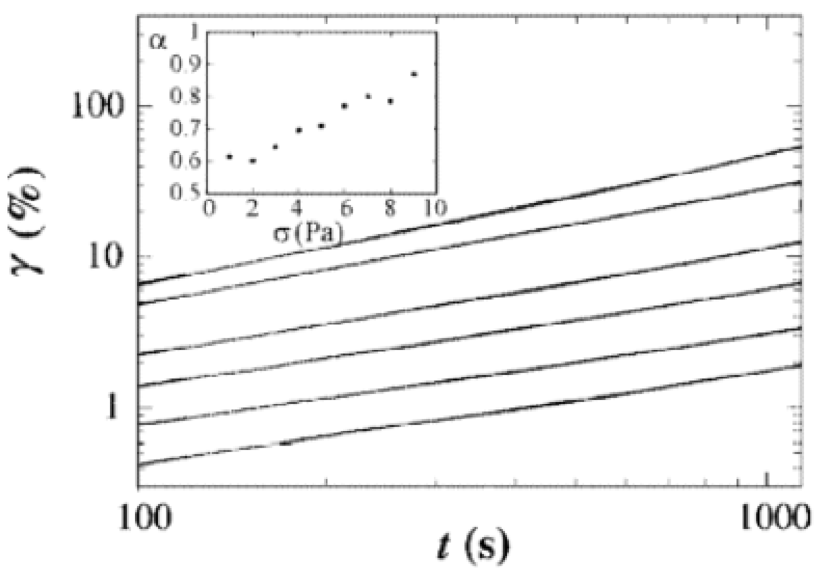

Figure 2: Log-log plot of Creep Properties

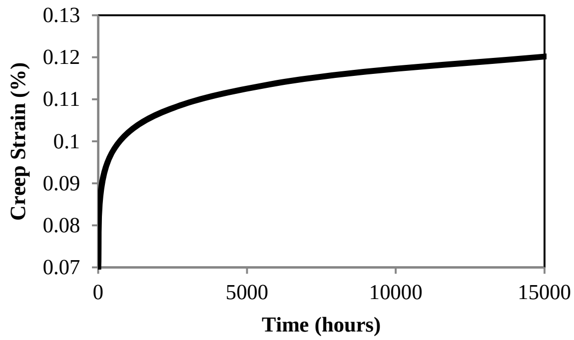

Figure 3: Linear Plot of Creep Curve

Stress-Strain tests for conductors have been performed by both Utilities and Vendors over the years both in general and a on a project-specific basis. As with any set of laboratory experiments, there are slight variations in the results that in this case yield slightly different stress – strain behavior. Figure 4 illustrates some historicalcurves from three different sources for 795 kcmil, “Drake”, ACSR.

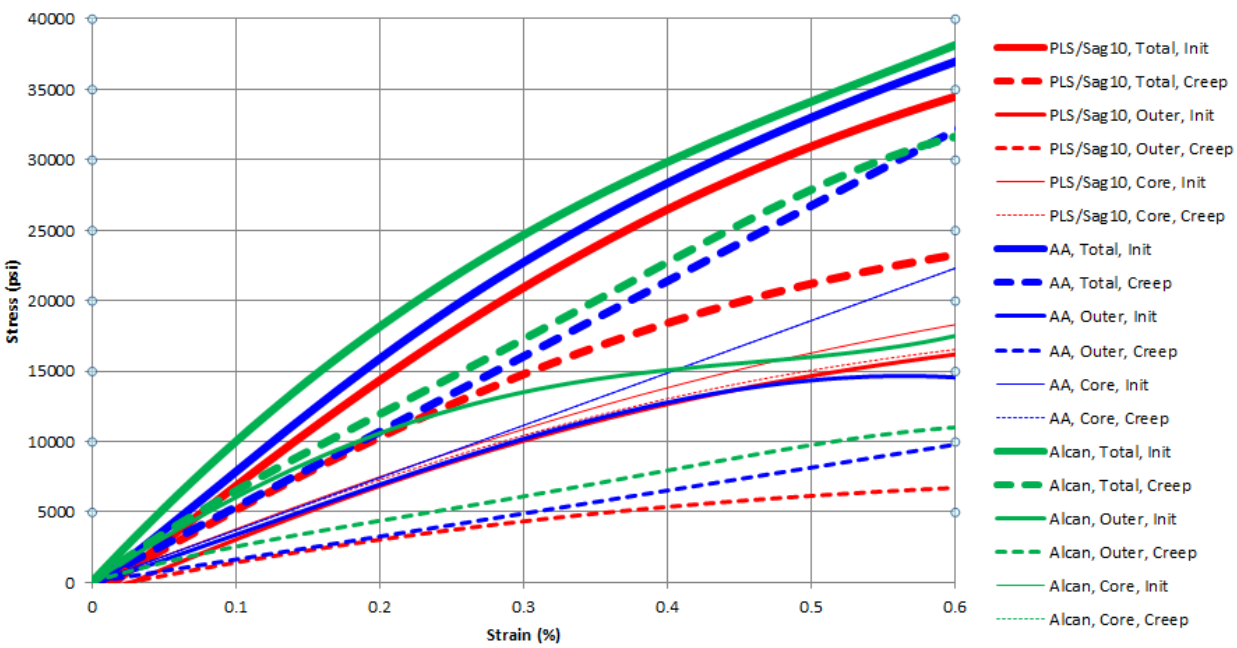

Figure 4: S-S Curves from Different Sources

VARIETY AND IMPACTS

In order to study the effects of these variations, we conducted parametric studies for three different scenarios:

Case Study #1:

- ACSR, 45/7, ~900 kcmil
- Stress-strain models from two different vendors

Case Study #2:

- AACSR, 45/7, ~900 kcmil
- Stress-strain models from two different vendors

Case Study #3:

- ACSS, Cardinal
- Stress-strain models from the same vendor, two different vintages

The studies were performed for span lengths ranging from 250’ to 4000’. Further studies adjusted the common point at 60°F, Initial with catenary value of 5,000’, 6,500’, and 8,000’.

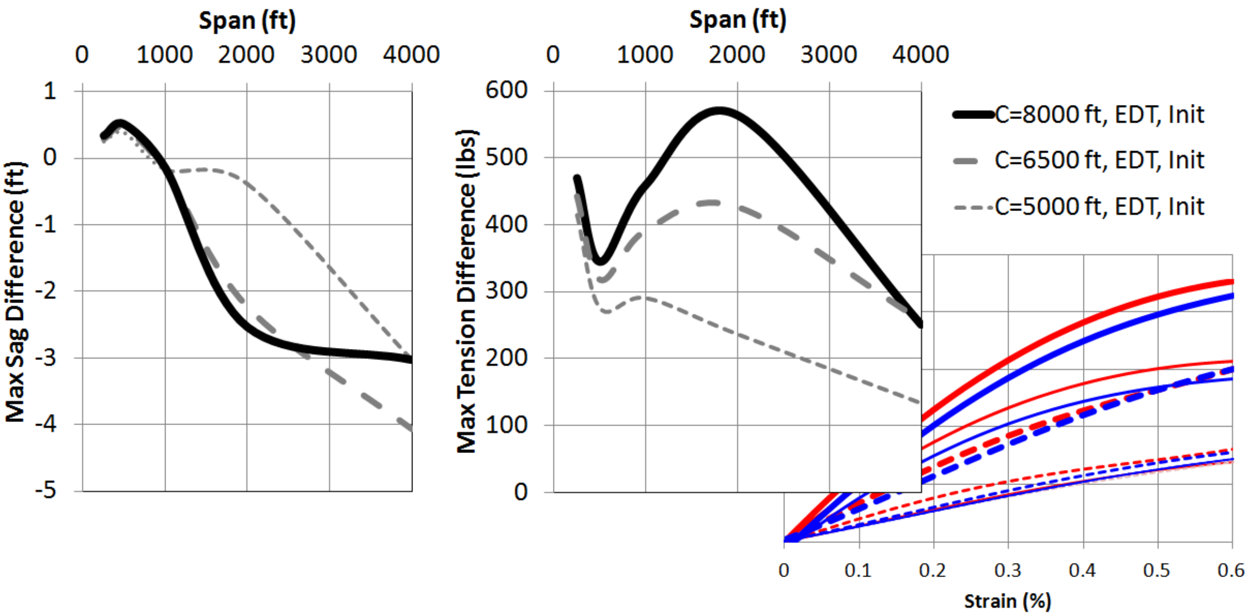

Figure 5: Case Study 1: Sag-Tension comparison varying span lengths and common points

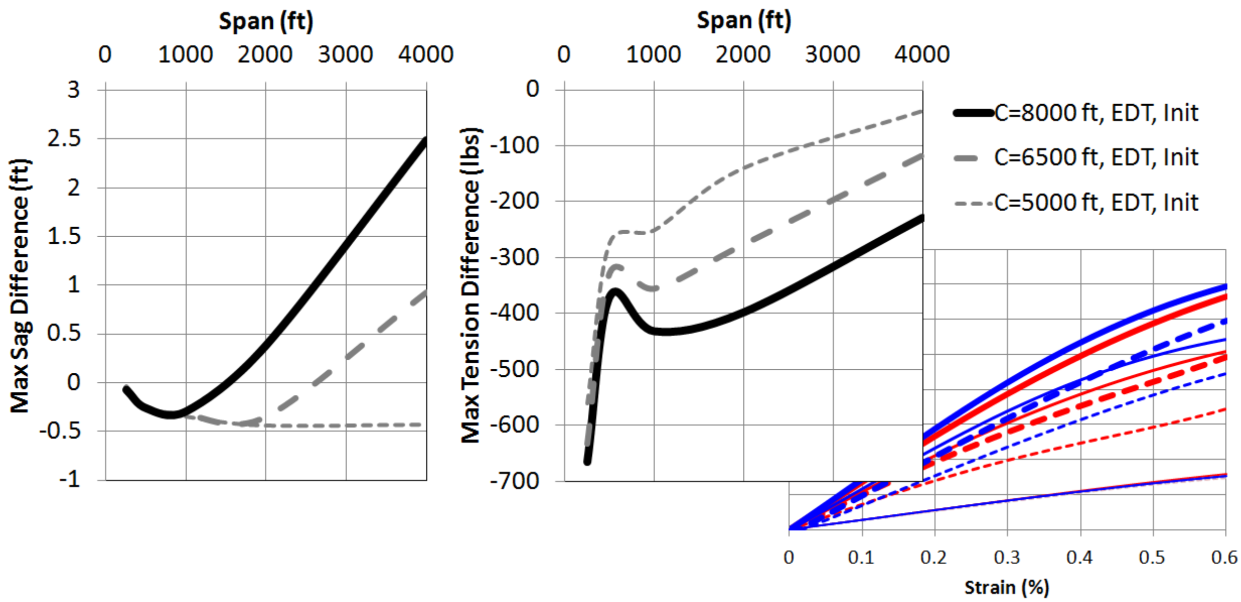

Figure 6: Case Study 2: Sag-Tension comparison varying span lengths and common points

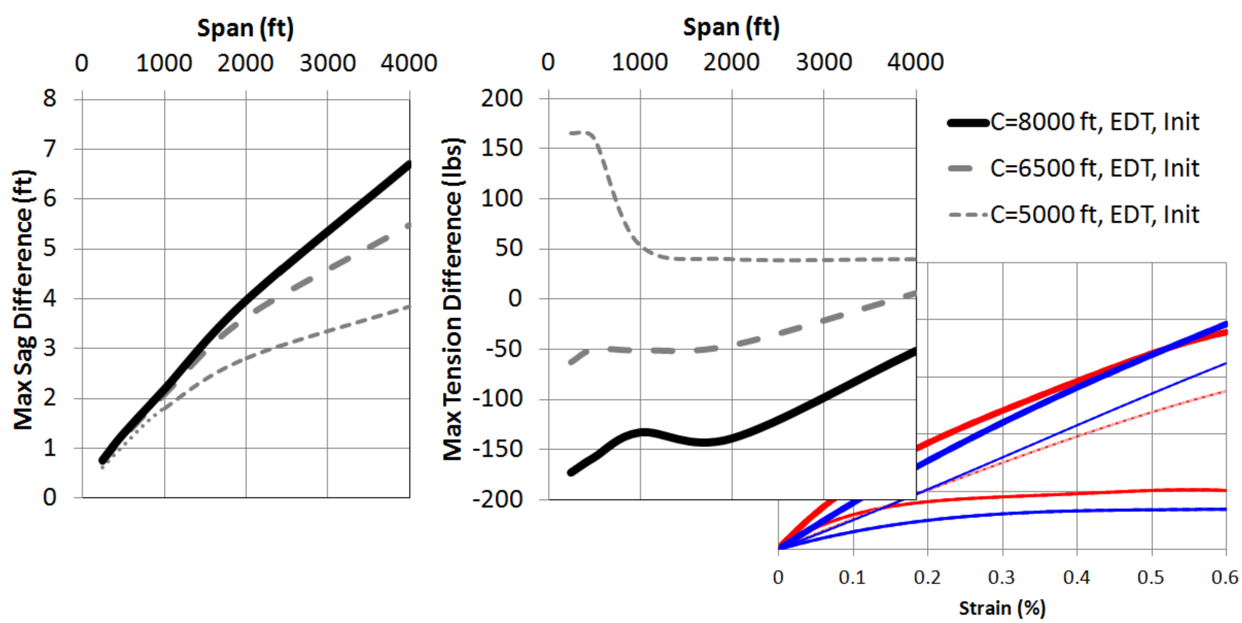

Figure 7: Case Study 3: Sag-Tension comparison varying span lengths and common points

In general these case studies show that long spans have a greater sag impact, shorter spans have greater tension impacts. Tight spans (high catenary values) are more sensitive to the variances in S-S data. The S-S behavior of the steel core was consistent among the different sources. There is less consistency in the behavior of the Aluminum stands, and the annealed aluminum has even less consistency. Table 1 below summarizes the results.

CASE STUDY	#1: ACSR	#2: AACSR	#3: ACSS
Sources	Different Vendor	Different Vendor	Same Vendor
Sag Impacts	~ 1’	~ 0.5’	~ 1-3’
Tension Impacts	~ 500 LBS	~ 500 LBS	~ 200 LBS

Table 1: Summary of Parametric Studies

APPLICATION AND REALITY

Proper application of stress-strain models requires the user to understand and answer the following questions:

1. What tensions will the conductor experience during its life? What is the creep tension?
2. Should the engineer consider the aluminum to take compression loading?
3. How much creep occurred during installation? Is it considered in the construction stringing data?

In the majority of cases, we consider the creep tension to be 60° F. However, the engineer needs to be aware that certain locations may have higher or lower average every day temperatures. The addition of marker ball is another situation where the 60°F assumption may lead to inaccuracies. Figure 8 shows the maximum temperature sag difference between an assumed creep tension of 60°F and 100°F.

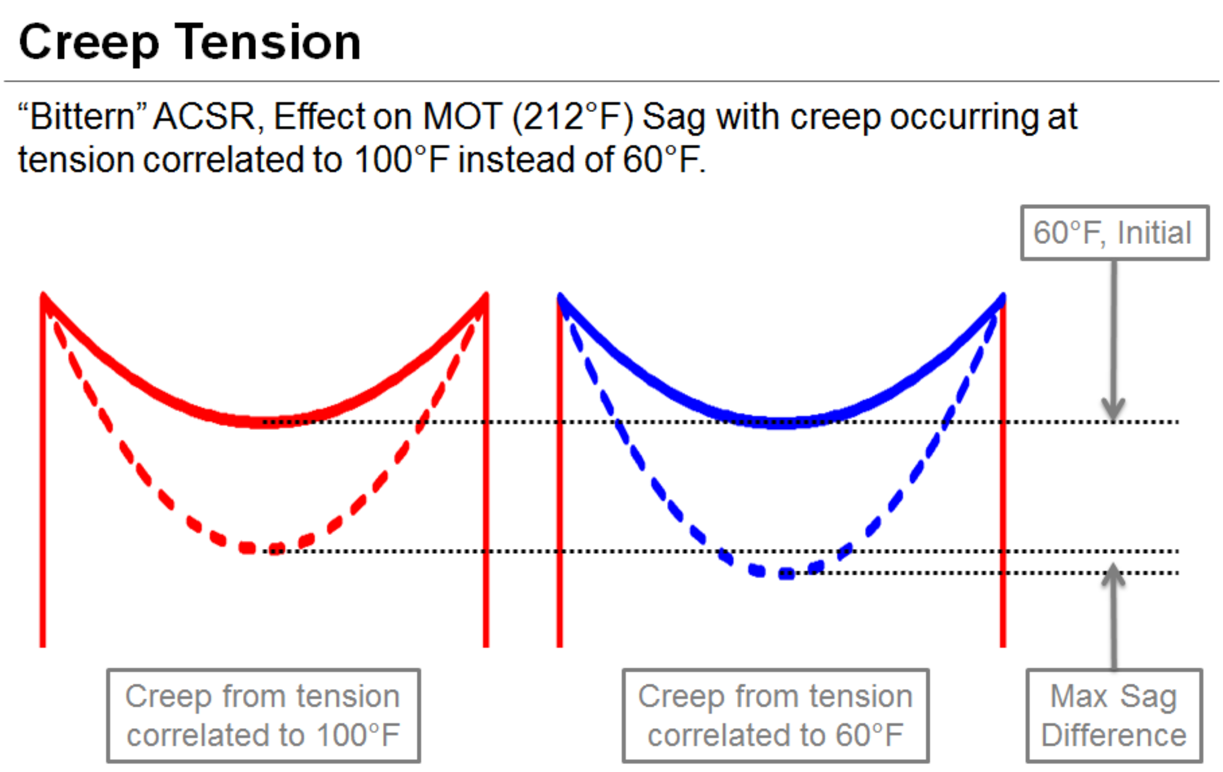

Figure 8

With ASCR conductors, in particular, the aluminum may be considered to go into compression at high temperatures because of the 2:1 differential in thermal elongation between aluminum and steel. Assuming the aluminum goes into compression will result in greater sags at higher temperatures. Figure 9 illustrates this for "Drake" ACSR.

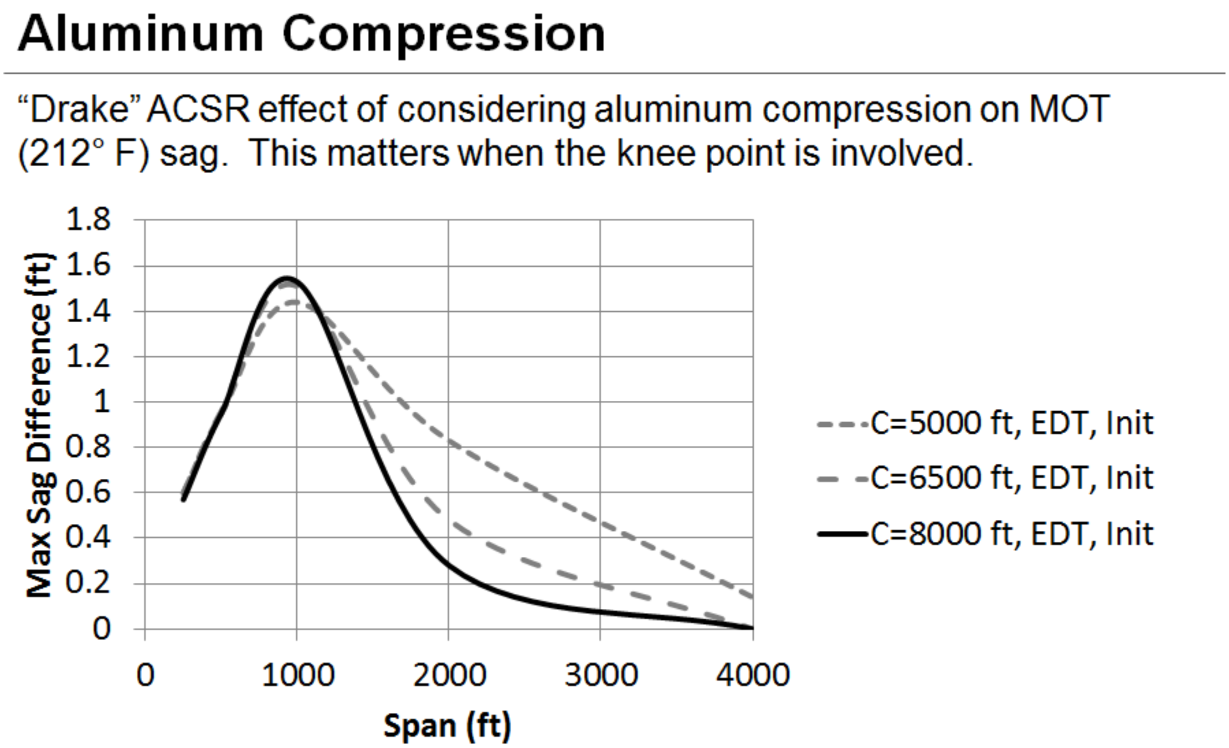

Figure 9

We typically develop construction sagging data using the initial (1 hour creep curve). Typically, sagging takes much longer. The IEEE 524 'Guide to the Installation of Overhead Transmission Line Conductors' states that "It is recommended that conductors not be allowed to hang in stringing blocks more than 24 hours before being pulled to the specified sag. If this time is exceeded, the cable manufacturer should be consulted to determine if short time creep correction factors are required".

Recall that the creep curve is very non-linear. The conductor has reached 13% of its lifetime creep in the first 24 hours as shown in Figure 10. This can be an important factor, especially when the conductor is held near the sagging tension prior to performing sagging for an extended period of time.

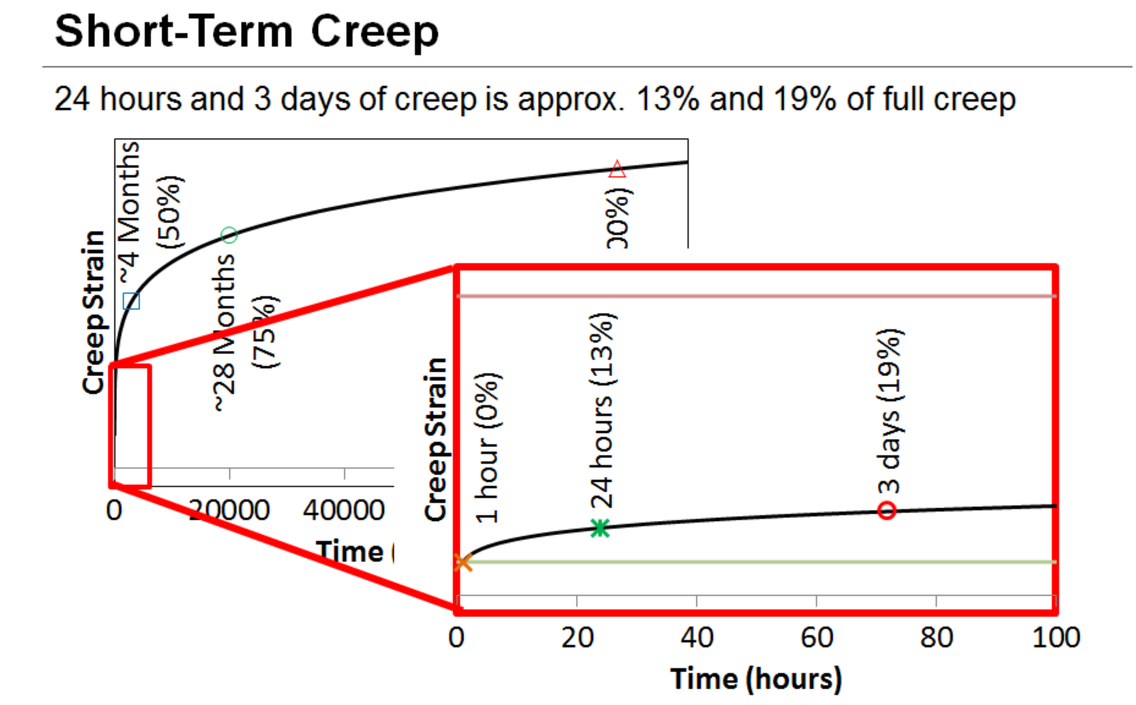

Figure 10

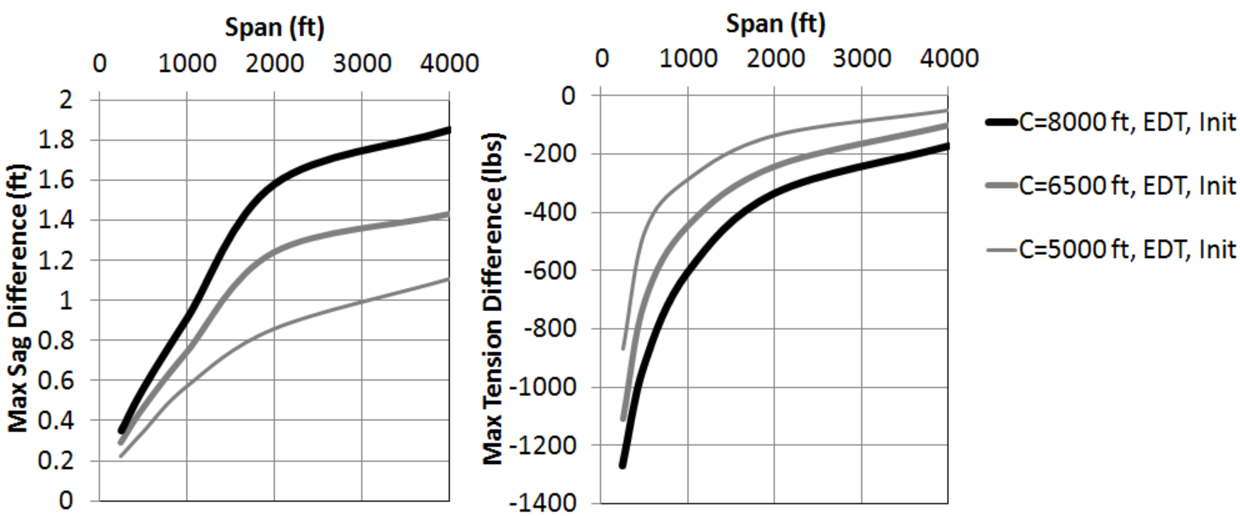

Figure 11: "Bittern" ACSR, Same install sags at 1 hour and 24 hour creep, assuming creep occurs at sagging tension

Even with accurate S-S models, our application choices can have significant impacts. An incorrect creep tension or ignoring the phenomenon of aluminum going into compression can each impact sag by a foot or more. Neglecting short-term creep when it should be considered can result in reduced sags and higher tensions.

CONCLUSIONS

Conductor vendors have made the following comments about the variations in Stress-Strain Curves:

In the process of analyzing these charts, we found a need to make some changes to the … charts and the conductors linked to them.

We recognize that much of the data supporting … charts is past retirement age. Accordingly, we are in the process of testing new-production conductor to provide full-range charts and better accuracy…

… warned that wire should only be expected to behave somewhat like the published data and not to expect exactness! Good Advice!

The good news is that overload and strength factors combined with conservative loading conditions often result in designs which can accommodate increased tensions. Also, design clearances often include buffers and in most cases, the maximum operating temperatures are rarely encountered.

The bad news is that these potential inaccuracies are sometimes not considered when setting requirements and expectations. A big concern is that a mis-placed sense of confidence with technology and software combined with pressure for increased line ratings are pushing the clearance limits.

The best thing we as engineers can do is strive to understand the inaccuracies applicable to your project and acknowledge them; educate those who think sag and tension are an exact science; consider providing short term creep graphs for sagging conductor; and be cautious of reducing or eliminating clearance buffers. In fact, we should consider increasing buffers for unique applications.

In the vast majority of our project work, we are within limits and bounds where these potential inaccuracies are negligible, but we need to be cognizant of them when working with excessively short or long spans,increased tensions or reduced margins.

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