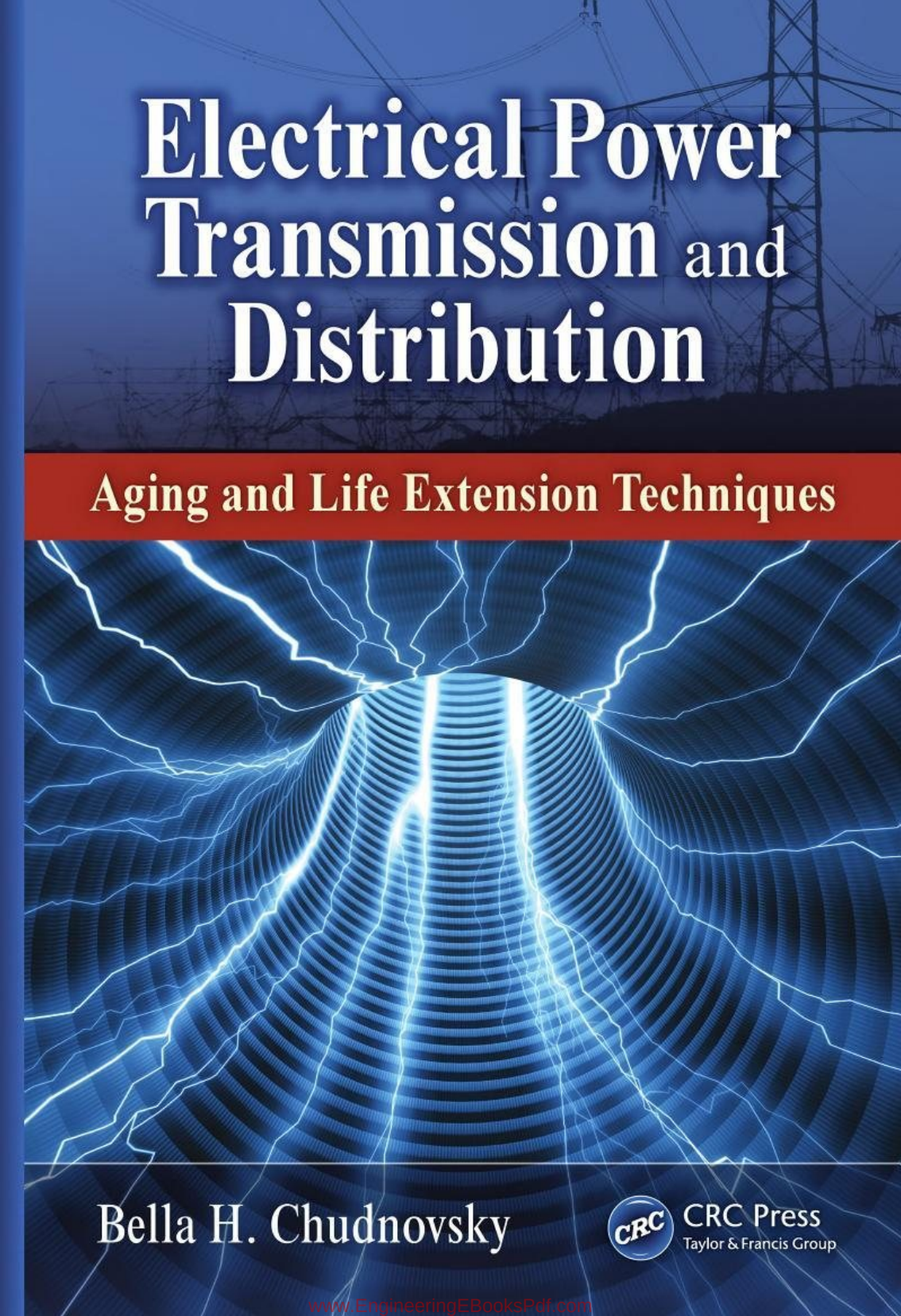




Electrical Power Transmission and Distribution

Aging and Life Extension Techniques

Bella H. Chudnovsky



CRC Press
Taylor & Francis Group

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Contents

Preface.....xxi

Author xxiii

Acronyms xxv

Chapter 1 Plating of Electrical Equipment 1

 1.1 Electroplating for Contact Applications 1

 1.1.1 Silver Plating 1

 1.1.1.1 Physical Properties of Silver Plating 1

 1.1.1.2 Silver Plating Thickness for Electrical Applications 2

 1.1.1.3 The Use of a Nickel Underplate for Silver Plating..... 2

 1.1.1.4 Types of Silver Platings 3

 1.1.2 Tin Plating 4

 1.1.2.1 Physical Properties of Tin Plating 4

 1.1.2.2 Tin Plating Thickness for Electrical Applications 5

 1.1.3 Nickel Plating 6

 1.1.3.1 Applications of Nickel Plating in the Electrical Industry 7

 1.1.3.2 Physical Properties and Thickness of Nickel Plating 7

 1.2 Electroless Plating 8

 1.2.1 Electroless Nickel: Physical Properties 9

 1.2.1.1 Chemical Composition and Structure of EN Plating 9

 1.2.1.2 Physical Properties of Electroless Ni Plating 9

 1.2.1.3 EN Film Thickness 10

 1.2.2 Electroless Nickel: Corrosion Resistance 11

 1.2.3 Electroless Nickel: Electrical Resistivity 11

 1.3 Electroless Nickel as a Plating Alternative for Electrical Apparatuses in Corrosive Atmosphere 12

 1.3.1 Testing of EN for Use in Electrical Applications 13

 1.3.1.1 Testing the Anticorrosion Properties of EN Plating 13

 1.3.1.2 Testing of the Electrical Properties of EN Plating 17

 1.3.2 Field Testing of EN-Plated Electrical Equipment in Energized Conditions 18

	1.3.2.1	Live Electrical Tests	19
	1.3.2.2	Electrical Properties of the Contactor Reconditioned with EN Plating	20
	1.3.2.3	Precaution in Electrical Applications of EN Plating	22
1.4		Zinc Electroplating and Galvanization.....	23
	1.4.1	Zinc Electroplating.....	23
	1.4.2	Zinc Galvanization Processes	24
	1.4.2.1	Hot-Dip Galvanizing	24
	1.4.2.2	Continuous Galvanizing	24
	1.4.2.3	Electrogalvanizing	24
	1.4.2.4	The Process of Galvanizing.....	25
	1.4.3	Conversion Zn Plating: Passivation with CrIII or CrVI	25
	1.4.3.1	Corrosion Resistance	25
	1.4.3.2	Color Variability	25
	1.4.3.3	Self-Healing Properties	26
	1.4.3.4	Identification	26
	1.4.3.5	The Cost Issue.....	26
1.5		Metal Whiskers on Plating (Noncorrosive Phenomenon)	26
	1.5.1	Whisker Phenomenon and Characteristics.....	26
	1.5.1.1	Conditions and Characteristics of Growth	27
	1.5.1.2	Environmental Factors.....	29
	1.5.1.3	Historical Account of Metal Whiskers Hazards.....	29
	1.5.2	Tin Whisker Mitigation Techniques.....	31
	1.5.2.1	Underplating	31
	1.5.2.2	Addition of Lead.....	31
	1.5.2.3	Heat Treatments.....	32
	1.5.2.4	Hot-Dip Tin Plating	32
	1.5.2.5	Thicker Tin Finish	32
	1.5.2.6	Conformal Coating	32
	1.5.2.7	Non-Tin Plating and Coating	32
	1.5.3	Tin Whiskers and the RoHS Initiative	33
	1.5.3.1	Lead-Free Solders.....	33
	1.5.3.2	“Pure” Tin Finishes	33
	1.5.4	Whisker Mitigation Levels Classification	34
	1.5.5	Whiskers on Other Metal Platings	35
1.6		Plating on Aluminum	37
	1.6.1	Use of Aluminum in Electrical Industry.....	37
	1.6.1.1	Choice of Plating	37
	1.6.1.2	Difficulties with the Plating of Aluminum ...	38
	1.6.2	Metals Used to Plate Aluminum.....	39
	1.6.3	Methods for Plating on Aluminum	39
	1.6.3.1	Plating Classifications.....	40

1.6.3.2	Pretreatment by Zincating	40
1.6.3.3	Tin Plating Techniques on Al	41
1.6.4	Quality of Tin Plating on Al for Different Plating Techniques	41
1.6.4.1	Adhesion Test.....	42
1.6.4.2	Thermal Shock Test	42
1.6.4.3	Plating Techniques and Adhesion of Tin Plating on Al	43
1.6.4.4	Plating Techniques and the Quality of Tin Plating on Al	43
1.7	Plating Standards and Glossary.....	45
1.7.1	National and International Standards and Regulations on Plating	45
1.8	Plating Glossary	47
	References	58

Chapter 2 Detrimental Processes and Aging of Plating 63

2.1	Issues of Tin Plating Performance.....	63
2.1.1	General Precautions in Using Tin Plating.....	63
2.1.1.1	Tin and Fretting Corrosion	63
2.1.1.2	Tin and Intermetallic Compounds.....	64
2.1.2	Thermal Deterioration of Tin Plating on Aluminum	64
2.1.2.1	Accelerated Aging Study of Tin Plating.....	65
2.1.2.2	Quality of Thermally Aged Tin Plating	66
2.1.2.3	Mechanisms of Thermal Deterioration of Tin Plating on Al	68
2.1.2.4	Tin Plating on Aluminum as a Possible Cause of Connection Overheating	69
2.1.3	Tin Pest.....	70
2.1.3.1	Definition of Tin Pest.....	70
2.1.3.2	Effects of Alloying Elements and the Environment on Tin Pest	70
2.1.3.3	Example of Tin Pest Failure in Electrical Connectors	72
2.1.3.4	Impact of RoHS on Possible Tin Pest Failures.....	72
2.2	Use of Underplating for Plating Longevity	73
2.2.1	Mitigating Role of Underplating	73
2.2.2	Advantages of Nickel as Underplating	74
2.2.2.1	Ni Underplating Provides a Diffusion Barrier	74
2.2.2.2	Ni Underplating Prevents the Formation of Intermetallics	75

	2.2.2.3	Ni Underplating Improves Wear Resistance.....	75
	2.2.2.4	Ni Underplating Increases Corrosion Resistance	75
	2.2.2.5	Other Advantages of Ni Underplating.....	76
	2.2.3	Recommended Thickness of Nickel Underplating	76
2.3		Applications of Ni Underplating	77
	2.3.1	Use of Ni Underplating for Tin Plating on Copper	77
	2.3.1.1	The Formation of Ni–Sn Intermetallics	77
	2.3.2	Nickel Underplating as a Tin Whisker Mitigation Technique	78
	2.3.3	Ni Underplating for Tin Plating on Aluminum.....	80
	2.3.3.1	Plating, Sample Preparation, and Testing Techniques	80
	2.3.3.2	Quality of the Plating and Interfaces.....	81
	2.3.3.3	Formation of Ni–Sn Intermetallics.....	82
	2.3.3.4	Comparison of Aging Behavior of Sn Plating with Ni, Bronze, or Cu Underlayer	82
	2.3.4	Ni Underplating for Gold Plating	84
2.4		Galvanic Corrosion: Connections Made of Dissimilar Metals	85
	2.4.1	Hazard: Galvanic Corrosion.....	85
	2.4.2	Definition of Dissimilar Metals	86
	2.4.3	Galvanic Corrosion of Copper-to-Aluminum Connections.....	87
	2.4.4	Protection of Copper-to-Aluminum Connections from Galvanic Corrosion.....	88
	2.4.4.1	Plated Aluminum Connections.....	89
	2.4.4.2	Fasteners	89
	2.4.4.3	Corrosion Protective Compound for Copper-to-Aluminum Connections	89
	2.4.5	Galvanic Corrosion in Steel Connections with Aluminum and Other Metals	90
	2.4.6	General Precautions to Minimize Galvanic Corrosion in Connections.....	91
2.5		Other Detrimental Processes Affecting Plating Performance	92
	2.5.1	Intermetallic Compounds.....	92
	2.5.1.1	Copper–Tin Intermetallic Compounds.....	92
	2.5.1.2	Effects of Temperature and Time on the Formation of Cu–Sn IMC.....	93
	2.5.1.3	Resistance of the Contacts with Tin Coating	94

2.5.2	Fretting Corrosion and a Means of Protection	94
2.5.2.1	Fretting Corrosion of Electrical Contacts	94
References		96

Chapter 3 Electrical Equipment in a Corrosive Environment 99

3.1	Corrosion Factors in the Atmosphere.....	99
3.1.1	Types of Corrosive Atmospheres	99
3.1.1.1	Indoor Atmosphere	99
3.1.1.2	Rural Atmosphere.....	99
3.1.1.3	Marine Atmosphere	100
3.1.1.4	Industrial Atmosphere	100
3.1.2	Factors Affecting Atmospheric Corrosion	101
3.1.2.1	Relative Humidity	101
3.1.2.2	Temperature	102
3.1.2.3	Deposition of Aerosol Particles	102
3.1.2.4	Pollutants, Corrosive Gases	103
3.1.3	Airborne Contamination in Data Centers	104
3.1.4	Zinc Whiskers	105
3.2	Effect of Environment on Bare Metals.....	106
3.2.1	Iron and Steel in Enclosures, Frames, Rails, and so Forth.....	106
3.2.2	Copper and Copper Alloys: Parts of the Conductive Path.....	107
3.2.3	Nickel and Nickel Alloys: Electrical Contacts and Plating.....	108
3.2.4	Aluminum and Aluminum Alloys in Electrical Applications.....	108
3.3	Atmospheric Corrosion of Silver Plating	110
3.3.1	Silver Plating Corrosion and Tarnish	111
3.3.1.1	Sulfuric Corrosion	111
3.3.1.2	Silver Tarnish.....	111
3.3.1.3	Silver Whiskers.....	113
3.3.2	Red-Plaque Corrosion	113
3.3.3	Underplating Corrosion.....	115
3.3.4	Effect of Silver Plating Thickness and Quality on Sulfuric Corrosion.....	116
3.3.5	Corrosion of a Copper Bus with Flash Silver Plating	116
3.4	Effect of Silver Corrosion on Contact Resistance	117
3.4.1	Silver Tarnish and Contact Electrical Resistance	117
3.4.1.1	Thickness of Silver Tarnish	118
3.4.1.2	Effect of the Current Load and Mechanical Load on the Corroded Contact Resistance.....	119
3.4.2	Techniques of Tarnish Cleaning.....	120

3.5	Silver Whiskers: A Mysterious and Dangerous Phenomenon	121
3.5.1	History of Silver Whiskers	121
3.5.2	Factors That Affect the Growth of Silver Whiskers	122
	3.5.2.1 Environmental Factors.....	122
	3.5.2.2 Plating Factors	122
3.5.3	Failures in Electrical Equipment Caused by Silver Whiskers	123
3.5.4	Study of the Silver Whisker Phenomenon.....	123
	3.5.4.1 Visual Appearance of the Whiskers	123
	3.5.4.2 Morphology	124
	3.5.4.3 Chemical Composition	126
	3.5.4.4 Chemical Composition of the Whisker Cross Section	126
3.5.5	Silver Whiskers Puzzle.....	127
	3.5.5.1 What Do We Know?	127
	3.5.5.2 What Do We Not Know or Understand?	127
	3.5.5.3 Questions Not Answered Yet.....	127
	3.5.5.4 Native Silver Wires	128
3.6	Tin Plating Corrosion	128
3.6.1	Tin Oxidation	129
3.6.2	Reaction of Tin with Other Gases	129
3.7	Zinc Plating Corrosion and Galvanized Steel	130
3.7.1	Atmospheric Corrosion of Zn	130
3.7.2	White Rust on Zinc	131
3.7.3	Galvanized Steel.....	132
3.7.4	Signs of Galvanized Steel Corrosion	133
	3.7.4.1 Rusting	133
	3.7.4.2 Pitting Corrosion.....	134
3.7.5	Factors Affecting Galvanized Steel Corrosion	135
	3.7.5.1 The Environment	135
	3.7.5.2 Thickness of Zinc Plating	135
3.7.6	Corrosion of Galvanized Steel in Circuit Breaker.....	136
3.8	Means of Corrosion Protection of Electrical Equipment.....	137
3.8.1	Protective Coatings for Conductive Parts, Enclosures, and Frames.....	137
	3.8.1.1 Metallic Coatings for Conductive Parts and Enclosures.....	137
	3.8.1.2 Polymeric Coatings and Paints for Enclosures and Frames	138
3.8.2	Means of Protection from Silver Corrosion	139
	3.8.2.1 Silver Protection from Corrosion.....	139
	3.8.2.2 Silver Plating Thickness	139
	3.8.2.3 Alternate Plating	140

3.8.3	Conversion Treatment	140
3.8.4	Chromium-Free Varnish-Preventative Processes	141
3.8.5	Means of Preventing the Corrosion of Zinc-Plated Steel Parts in Electrical Equipment.....	141
3.8.6	Vaporized Corrosion Inhibitors.....	142
3.8.7	Lubrication	142
3.9	Means of Environmental Control for Corrosion Protection.....	143
3.9.1	Assessment of Electrical and Electronic Equipment Exposure to Corrosive Environment	143
3.9.2	Air Quality Monitoring	144
3.9.3	Direct Gas Monitoring	145
3.9.4	Corrosion Control Technology	145
3.9.5	Chemical and Particulate Filtration	147
3.9.6	Temperature Control	147
3.10	Corrosion Glossary.....	148
	References	160

Chapter 4 Lubrication of Distribution Electrical Equipment..... 165

4.1	Lubrication Primer	165
4.1.1	Purpose of Lubrication.....	165
4.1.2	Lubrication Terminology.....	166
4.1.3	Types of Lubricating Materials	167
4.1.3.1	Oil	167
4.1.3.2	Synthetic Oils	167
4.1.3.3	Grease	168
4.1.3.4	Synthetic Lubricants	168
4.1.3.5	Solid Lubricants.....	169
4.1.3.6	Silicones.....	169
4.1.4	Grease Composition and Properties.....	169
4.1.4.1	Properties of Greases with Different Types of Thickeners.....	170
4.1.4.2	Additives	171
4.2	Incompatibility of Lubricants	173
4.2.1	Definition of Incompatibility.....	173
4.2.2	Causes of Incompatibility.....	174
4.2.2.1	Base Oils.....	174
4.2.2.2	Thickeners	174
4.2.2.3	Additives	176
4.3	Lubricant Working Temperature Limits and Storage.....	176
4.3.1	Lubricant Working Temperature	176
4.3.1.1	Temperature Limits	176
4.3.1.2	Maximum Temperature	177
4.3.1.3	Minimum Temperature.....	177
4.3.2	Lubricant Storage Conditions and Shelf Life.....	177

4.4	Lubrication of Electrical Contacts.....	178
4.4.1	Principles of Contact Lubrication	179
4.4.2	Choice of Lubricants Based on Design and Contact/Plating Materials	179
4.4.3	Lubrication as Protection from Fretting Corrosion, Mechanical Wear, and Friction	183
4.4.4	Lubrication as Protection from Corrosion.....	184
4.4.5	Durability of Lubricants.....	185
4.5	Practical Lubrication	186
4.5.1	Periodic Lubrication Maintenance of Electrical Power Equipment	186
4.5.1.1	Cleaning.....	186
4.5.1.2	Penetrating Oil.....	186
4.5.1.3	Lubrication in Field	187
4.5.1.4	Troubleshooting Lubrication	187
4.5.2	General Lubrication Recommendations for Electrical Equipment.....	187
4.5.2.1	Choice of Lubricants.....	187
4.5.2.2	OEM Specifications	188
4.5.2.3	Change of Lubrication Product.....	188
4.5.2.4	Lubrication of Electrical Contacts.....	188
4.5.2.5	Application of Lubricants	188
4.6	Lubrication Failure Modes	189
4.6.1	Causes of Lubrication Failure	189
4.6.2	Wrong Lubricant for Application	190
4.6.3	Thermal Limitations	190
4.6.4	Lubricant Composition and Wrong Amount of Lubricant	191
4.6.5	Contaminants or Corrosives in the Lubricant	191
4.6.6	Environmental Factors Causing Grease Deterioration.....	192
4.6.7	Lubricants' Incompatibility.....	193
4.7	Lubrication Failures of Electrical Equipment: Case Studies....	193
4.7.1	CB Failures Caused by Lubrication at U.S. Commercial Nuclear Power Plants.....	193
4.7.2	Overheating of the MV Switch	194
4.8	Informational Sources for Lubricants	198
4.9	Lubrication Glossary	201
	References	208

Chapter 5	Insulation, Coatings, and Adhesives in Transmission and Distribution Electrical Equipment	215
5.1	Insulating Materials in Power Equipment.....	215
5.1.1	Insulating Materials Used in the Electrical Industry.....	215

5.1.2	Thermal Limitation for Electrical Insulation.....	219
5.1.3	Thermal Degradation of Insulators	222
5.1.4	Temperature Limitations for Switchgear Assembly Based on Insulation Class.....	223
5.2	Aging of Insulating Materials due to Electrical Stress	224
5.2.1	Electrical Breakdown in Insulation.....	224
5.2.2	Corona	225
5.2.2.1	Destructive Nature of Corona.....	225
5.2.2.2	Corona Tracking	226
5.2.2.3	Corona in Switchgear.....	227
5.2.3	Partial Discharge	227
5.2.3.1	Partial Discharge in Switchgear	230
5.2.3.2	Partial Discharge in Paper-Insulated HV Cables.....	230
5.3	Environmental Aging of Insulating Materials	231
5.3.1	Insulation Deterioration under Environmental Conditions	231
5.3.2	Biological Contamination and Corrosion of Insulators.....	232
5.3.3	Environmental Aging of Insulators in Transmission Lines.....	232
5.3.4	Stress Corrosion Cracking in Composite Insulators	233
5.4	HV Bushings in Transformers and CBs	234
5.4.1	Types of Bushings	234
5.4.2	Bushings: Possible Causes of Failures	235
5.5	Power Cable Insulation.....	236
5.5.1	Cable Insulation Types	237
5.5.2	Aging of Cable Insulating Materials.....	238
5.5.2.1	XLPE Cable Insulation Degradation	238
5.5.2.2	Electrical and Water Treeing	239
5.6	Other Insulating Media	239
5.6.1	Insulating Oil.....	239
5.6.1.1	Transformer Oil	239
5.6.1.2	Oil Switches and CBs	240
5.6.1.3	Aging of Transformer Oil.....	240
5.6.1.4	Thermal and Electrical Faults of Transformer Oil	241
5.6.2	Sulfur Hexafluoride (SF ₆) as Insulating and Cooling Media.....	243
5.6.2.1	Insulating Properties and Decomposition of SF ₆	243
5.6.2.2	SF ₆ as a Greenhouse Gas	244
5.6.3	Air and Vacuum as Insulating Media.....	244
5.7	Powder Coating and Paint for Electrical Enclosures.....	245
5.7.1	Electrical Enclosures: Types and Materials	245

5.7.2	Powder Coating/Paint Used for Enclosures	246
5.7.2.1	Criteria for Paint Type Selection	246
5.7.2.2	Techniques of Applying a Powder Coating/Paint to Metal Panels	247
5.7.3	Defects and Failures of Powder Coatings and Paints	249
5.7.4	HV RTV Coating	251
5.7.4.1	Aging of RTV Insulation	252
5.7.4.2	The Role of Fillers in RTV Coatings	252
5.8	Electrical Insulation Standards and Glossary	253
5.8.1	National and International Standards and Regulations on Insulation.....	253
5.8.1.1	North American Standards for Solid Insulation.....	253
5.8.1.2	International Standards for Solid Insulation.....	254
5.8.1.3	National and International Standards for Transformer Oil.....	256
5.8.1.4	National Standards for Paints and Coatings for Steel.....	256
5.8.2	Insulation Glossary.....	256
5.8.2.1	Solid Insulation Glossary.....	256
5.8.2.2	Insulating Oil Glossary.....	261
	References	263

Chapter 6 Electrical Equipment Life Expectancy, Aging, and Failures 269

6.1	Life Expectancy for Distribution and Transmission Equipment	269
6.1.1	Estimation of Electrical Equipment Lifetime	269
6.1.2	Overloading and Estimated Life of Electrical Equipment.....	270
6.1.2.1	Circuit Breakers	270
6.1.2.2	Transformers	270
6.1.2.3	Conductors	271
6.1.2.4	Underground Transmission.....	271
6.1.3	Temperature and Estimated Life of Electrical Equipment.....	271
6.2	Signatures of Aging of Electrical Equipment in Nuclear, Industrial, and Residential Environments	272
6.2.1	Aging Factors	272
6.2.2	Aging Equipment in an Industrial Environment.....	273
6.2.2.1	Nuclear Facilities	273
6.2.2.2	Aviation.....	273
6.2.2.3	Chemical and Oil Refining Industries	274

6.2.3	Aging Equipment in Power Generation and Transmission and Distribution	274
6.2.3.1	Overhead Power Transmission	274
6.2.3.2	Power Plant	274
6.2.4	Aging Power Equipment in a Residential Environment	275
6.2.4.1	Aging of Conductors.....	277
6.2.4.2	Aging of Insulation	277
6.2.5	Aging Electrical Equipment in Rural/Agricultural Applications.....	277
6.3	Failure Modes and Failure Rates of Aging Electrical Equipment	278
6.3.1	Definitions of Failure, Failure Mode, and Failure Rate of Electrical Equipment	278
6.3.2	The Bath Tub Curve, the Hypothetical Failure Rate vs. Time.....	279
6.3.3	Failure Causes of CBs	280
6.3.3.1	LV and MV CB Failure Causes	280
6.3.3.2	Failures of Circuit Breakers According to the <i>IEEE Gold Book</i>	281
6.3.4	Failure Causes and Failure Rates of Power Transformers	282
6.3.4.1	MV and LV Power Transformers.....	282
6.3.4.2	HV Power Transformers	282
6.3.5	Failure Causes of MV Switchgear	283
6.3.6	Failure Causes of Other MV and LV Power Electrical Equipment.....	284
6.3.7	Failure Causes of Power Connectors.....	285
6.3.7.1	Aluminum Connectors	286
6.3.7.2	Corrosion	286
6.3.7.3	Contact Fretting	286
6.3.7.4	Stress Relaxation	287
6.3.8	Inadequate Maintenance and Maintenance Quality as a Cause of Failure	287
6.4	Failure Causes and Rates of Electrical Equipment Based on CIGRÉ Survey	288
6.4.1	Results of the Older CIGRÉ Surveys of HV CB Failures.....	289
6.4.1.1	Main Results of the First Survey	290
6.4.1.2	Maintenance Aspects.....	290
6.4.1.3	Mechanical Aspects.....	290
6.4.2	Failure Causes of GIS.....	290
6.4.2.1	Older CIGRÉ Surveys	290
6.4.2.2	Major GIS Failure Modes.....	291
6.4.2.3	Age of CIS and Major Failure Mode Distribution	291

	6.4.2.4	Location, Origin, and Environmental Contribution in GIS Major Failure	291
	6.4.2.5	Component and Voltage Class of CIS	292
	6.4.2.6	Age of GIS Components	292
	6.4.2.7	Service Conditions of Major Failure Discovery	292
	6.4.2.8	Time of MF Cause Introduced	292
	6.4.2.9	Age of the CIS and Primary Cause of the Failure	293
	6.4.2.10	Failure Rates of GIS Components	293
	6.4.3	Failure Causes of SF ₆ CBs	293
	6.4.4	Failure Causes of Disconnectors and Earthing Switches.....	294
6.5		Failure Cases of High-Voltage Electrical Equipment.....	294
	6.5.1	Failures of HV Bushings.....	294
	6.5.2	Failures of HV Transformers	295
	6.5.2.1	Case: Failure of Winding Insulation and Bushing	295
	6.5.3	Failure Mechanisms of HV Transformers and Bushings	296
	6.5.4	Failures of HV CBs	297
	6.5.4.1	Case 1: Failure of Mechanical Linkage	297
	6.5.4.2	Case 2: Trapped Water in Internal Bolt Holes	297
	6.5.4.3	Case 3: Contact Jamming or Mechanism Failure	298
6.6		Failure Cases of Low- and Medium-Voltage Electrical Equipment	299
	6.6.1	Bushing Failures in MV Switchgear	299
	6.6.2	Case Studies of MV Switchgear Failures.....	300
	6.6.2.1	Case 1: Component Defect	301
	6.6.2.2	Case 2: Arcing, Design Errors.....	301
	6.6.2.3	Case 3: Flashover, Water Condensation	301
	6.6.2.4	Case 4: Overheating.....	301
	6.6.3	Metal-Clad Switchgear Failures.....	302
	6.6.3.1	Case 1: Failure of the 25-Year-Old Circuit Breaker, and Lack of Maintenance	302
	6.6.3.2	Case 2: Insulator Failure.....	302
	6.6.4	Failure of MV Power Cables.....	303
	6.6.5	LV Switchboard Failure	303
	References		305

Chapter 7	Physical Conditions of Electrical Equipment: Testing, Monitoring, and Diagnostics	309
7.1	Parameters Defining the Physical Conditions of Electrical Equipment	310
7.1.1	Transformers	310
7.1.2	HV Bushings	310
7.1.3	Circuit Breakers.....	310
7.1.4	Switchgear.....	310
7.1.5	Power Cables	311
7.2	Techniques for Testing Physical Conditions of MV Cables.....	311
7.2.1	Comparison of MV Cable Testing Techniques	312
7.2.2	High Potential Withstand Test.....	313
7.2.2.1	DC HIPOT Test	313
7.2.2.2	Very Low-Frequency HIPOT Test.....	314
7.2.2.3	AC Power Frequency HIPOT	315
7.2.3	PD Diagnostics	315
7.2.4	Choice of MV Cable Diagnostics.....	316
7.3	Testing Techniques to Assess Insulation Conditions of HV/MV Switchgear, CBs, and Transformers.....	317
7.3.1	Insulation Condition: PD Testing	317
7.3.1.1	PD Mechanism and Effect on Insulation ...	317
7.3.1.2	Ultrasonic Detection of PD.....	318
7.3.1.3	PD Detection Using Transient Earth Voltages.....	318
7.3.2	Diagnostics of Oil Condition.....	319
7.3.2.1	Dissolved Gases in Oil.....	319
7.3.2.2	Water, Acids, and Furans in Oil	320
7.3.2.3	Power Factor of Transformer Oil.....	322
7.3.2.4	Techniques of Oil Diagnostics.....	322
7.3.2.5	Online Monitoring of Transformer Oil Conditions.....	323
7.4	Online Monitoring Techniques for PD of MV Substations, Switchgear, and Cables	324
7.4.1	PD Detection in Substations, Switchgear, and Cables	325
7.4.2	Monitoring PDs with Fiber-Optic Technology	325
7.5	Testing of HV Bushing Conditions	326
7.6	Thermal Conditions of Electrical Equipment and Temperature Monitoring.....	327
7.6.1	Temperature Measurement Using Thermography ...	328
7.6.2	Continuous Temperature Measurement	328
7.6.2.1	IR Noncontact Temperature Sensors	328
7.6.2.2	Electronic Temperature Sensors	329

7.6.3	Fiber-Optic Technology for Temperature Measurement	329
7.6.3.1	Optical Fiber Sensing Probe	329
7.6.3.2	Distributed Fiber-Optic Temperature Sensing	330
7.6.4	Winding Temperature Monitoring of HV Transformers with the Fiber-Optic Technique	331
7.6.5	Wireless Temperature Monitoring	332
7.6.5.1	Structure, Benefits, and Problems of Wireless Temperature-Monitoring Systems	332
7.6.5.2	Thermal Diagnostics.....	333
7.6.5.3	Wireless Temperature Sensors: Power Source	333
7.6.5.4	Wireless Temperature Monitoring Techniques.....	334
7.6.5.5	Wireless Temperature Monitoring with SAW Sensors.....	335
7.7	Physical Conditions of Transmission Electrical Equipment: Online Monitoring Techniques.....	336
7.7.1	Condition Monitoring Technologies in Electrical Transmission	336
7.7.2	Overhead Transmission Lines	336
7.7.3	Properties of Transmission Overhead Lines to Monitor, Sensing Elements and Monitoring Techniques.....	338
7.7.3.1	Conductor Sag Measurements	339
7.7.3.2	Conductor Temperature Measurements	339
7.7.3.3	Combined Monitoring Solutions	341
	References	342

Chapter 8 Electrical Equipment Maintenance and Life

	Extension Techniques	347
8.1	Maintenance Strategies	347
8.2	Maintenance as a Life Extension Technique.....	349
8.2.1	Time-Based Maintenance	349
8.2.2	Maintenance of Power Circuit Breakers	349
8.2.2.1	Molded Case Circuit Breakers.....	349
8.2.2.2	Low-Voltage Circuit Breakers	350
8.2.2.3	Medium-Voltage Circuit Breakers	350
8.2.2.4	High-Voltage Circuit Breakers.....	350
8.2.2.5	SF ₆ Gas Circuit Breakers	351
8.2.3	Periodic Lubrication of the Power Circuit Breaker.....	351
8.2.4	Refurbishment or Reconditioning	352
8.2.5	Condition-Based Maintenance	354

	8.2.5.1	High-Voltage Switchgear	354
	8.2.5.2	MV Switchgear	355
8.3		CBM Methodology and Life Management.....	356
	8.3.1	Distribution Power Transformers	356
	8.3.1.1	Level 1 Diagnostic Techniques.....	356
	8.3.1.2	Level 2 Diagnostic Techniques.....	357
	8.3.1.3	Level 3 Diagnostic Techniques.....	357
	8.3.1.4	Transformer Health Index.....	357
	8.3.2	Power Cable Systems	358
	8.3.2.1	Cable Deterioration Diagnostics.....	358
	8.3.2.2	CBM and Life Extension of Power Cables	359
8.4		Maintenance of Electrical Equipment Exposed to Corrosion and Water.....	360
	8.4.1	Water-Damaged Electrical Equipment.....	360
	8.4.2	Electrical Equipment in Nuclear Industry.....	361
		References	363
		Index.....	367

Preface

Every transmission and distribution apparatus is a complex engineering system of electrical and mechanical components made of various conductive and insulating materials. When in service, these systems are exposed to multiple environmental stresses (atmospheric corrosive gases, contaminants, high and low temperatures); mechanical stresses (vibrations, shocks, handling); electrical stresses and electrostatic discharges; and many other internal and external impacts. The effect of stresses is cumulative, leading to progressive damage and significant deterioration (aging) of the electrical systems. Continuous aging sooner or later results in the disruption or even the complete depletion of the ability of the electrical apparatus to function properly and safely.

A thorough analysis of the factors that accelerate aging and cause the failure of various materials in electrical apparatuses suggests multiple techniques for diminishing the impact of deteriorating factors, thus preventing a premature failure. Various aging-mitigating procedures extending the life of the electrical equipment have emerged and have become available. The author's purpose is to help find proper ways to slow down the aging of electrical apparatuses, improve their performance, and extend the life of power transmission and distribution equipment.

This book is designed to serve as a reference manual for engineering, maintenance, and training personnel to aid in understanding the causes of equipment deterioration. Under one cover, it makes available extensive information that is very hard to obtain since it is scattered among many different sources such as manufacturers documentation, journal papers, conference proceedings, and general books on plating, lubrication, insulation, and so on.

The information accumulated here is an important source of practical knowledge for different audiences, including electrical and maintenance engineers and technical personnel responsible for the utilization, operation, and maintenance of transmission and distribution electrical equipment at virtually every power plant and industrial facility. College instructors and professors may use this source as supplemental material for teaching classes on electrical equipment maintenance concepts and procedures. Industrial training personnel may use this book to develop manuals on proper maintenance procedures and choice of materials. It teaches electric maintenance personnel to identify the signs of equipment aging and recommends various techniques for the protection of electrical apparatus from deterioration and damage.

This book combines research and engineering material with practical maintenance recommendations given in layman's terms, which makes it useful for audiences of various levels of education and experience.

Author

Bella Helmer Chudnovsky earned her PhD in applied physics at Rostov State University (RSU) in Russia. For the first 25 years of her career, she worked as a successful scientist for the Institute of Physics at RSU and at the University of Cincinnati. During the last 12 years of her career, she worked as an R&D engineer for Schneider Electric-Square D Company, where her principal areas of activities were aimed at resolving multiple aging problems of power distribution equipment. In this field, she has published 40 papers in national and international technical journals and conferences proceedings on topics that are summed up in the book.

Acronyms

A

AAC	all aluminum conductor
AAAC	all aluminum alloy conductor
AB	alkylbenzenes
AC	alternate current
ACAR	aluminum conductor aluminum-alloy reinforced
ACCC	aluminum conductor composite core
ACGIH	American Conference of Governmental Industrial Hygienists
ACSR	aluminum conductor steel reinforced
AGMA	American Gear Manufacturers Association
AIS	air-insulated substations
AMG	aging management guidelines
AMS	aerospace material specification
ANSI	American National Standards Institute
ASTM	American Society for Testing of Materials
ATH	alumina trihydrate

C

CB	circuit breaker
CBM	condition-based maintenance
CCF	common-cause failures
CCT	continuous current test
CD	current density
CIC	cable in conduit
CIGRE	International Council on Large Electric Systems (Conseil International des Grands Réseaux Électriques)
CM	corrective maintenance
COTS	Commercial Off-The-Shelf
CR	contact resistance
CSPE	chlorosulfonated polyethylene (synthetic rubber)
CT	current transformer

D

DC	direct current
DDF	discharge dissipation factor
DES	disconnectors and earthing switches
DGA	dissolved gas analysis
DOD	Department of Defense
DOE	Department of Energy

DP	degree of polymerization
DPC	diphenylcarbazine (test)
DS	disconnect switch
DTS	distributed temperature sensing
DWV	dielectric withstanding voltage

E

EC	electrical conductor (grade of aluminum)
EDS	energy-dispersive x-ray spectroscopy
EIM	electrical insulating material
EIS	electrical insulating system
EMAT	electro-magnetic acoustic transducers
EMI	electro-magnetic interference
EN	electroless nickel
ENIG	electroless nickel immersion gold
EP	electrode potential
EP	extreme pressure
EPDM	ethylene propylene diene monomer
EPM	electrical preventive maintenance
EPR	ethylene propylene rubber (type of cable insulation)
EPRI	Electric Power Research Institute
ES	earthing switch
ETFE	modified ethylene tetrafluoroethylene (type of cable insulation)

F

FA	fatty acid
FAA	Federal Aviation Administration
FEP	fluorinated ethylene propylene (type of cable insulation)
FFA	furfural analysis
FOTC	fiber-optic transmission conductor
FOV	field of view
FRA	frequency response analysis
FTR	fiber-optic transceiver
FxHy	fluorinated thiol
FxOHy	fluorinated ether thiol

G–H

GCA	general condition assessment
GIS	gas-insulated substation or switchgear
GRP	glass-reinforced plastic
GTPP	geothermal power plant
HASL	hot air solder leveled
HDG	hot-dip galvanizing
HF	high frequency

HK	Knoop hardness
HMWPE	high-molecular weight polyethylene (type of cable insulation)
HP	high potential
HPEN	electroless nickel with high content of phosphorus
HPLC	high-performance liquid chromatography
HSLA	high-strength, low-alloy (steel)
HV	high voltage
HVAC	heating, ventilation, and air conditioning
HVIC	high-voltage insulator coating

I

IACS	international annealed copper standard
IC	integrated circuit
ICPC	inductively coupled plasma spectroscopy
IDLH	immediately dangerous to life or health
IDT	interdigital transducers
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IMC	intermetallic compound
iNEMI	International Electronics Manufacturing Initiative
IR	insulation resistance
IR	infrared
ISM	industrial, scientific, and medical (radio bands)
ISO	International Standards Organization
IT	intellectual technology
IT	instrument transformer
ITAA	Information Technology Association of America

L–M

LDM	laser distance meter
LPEN	electroless nickel with low content of phosphorus
LTC	load tap changer
LV	low voltage
MCC	motor control center
MCCB	molded case circuit breaker
MCW	microcrystalline wax
MEMS	micro electro-mechanical system
MF	major failure
mf	minor failure
MFG	manufacturer
MFG	mixed flowing gas (test)
MSDS	material safety data sheet
MTTF	mean time to failure
MV	medium voltage

N

NASA	National Aeronautics and Space Administration
NCI	non-ceramic insulator
NEC	National Electric Code
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturers Association
NEPP	NASA Electronic Parts and Packaging
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
NLGI	National Lubricating Grease Institute
NOX	nitrogen oxides
NRS	Nuclear Regulatory Commission
NUMARC	Nuclear Management and Resources Council

O

OCB	oil circuit breaker
OEM	original equipment manufacturer
OHTL	overhead transmission line
OLTC	on-load tap changer
OQA	oil quality analysis
OSHA	Occupational Safety and Health Administration
OSP	organic solderability preservative

P

PAG	polyalkylene glycol
PAO	polyalphaolefins
PBB	polybrominated biphenyl
PBDE	polybrominated diphenyl ether
PCB	printed circuit boards
PCB	polychlorinated biphenyls
PD	partial discharge
PdM	predictive maintenance
PE	polyethylene
PF	power frequency
PFAE	perfluoropolyalkylether
PFPE	perfluorinated polyether
PILC	paper insulated, lead covered (type of cable insulation)
PM	periodic maintenance
POE	polyolesters
PPE	polyphenyl ether (type of cable insulation)
PPLP	laminate of paper with polypropylene (type of cable insulation)
PPP	paper with polypropylene (type of cable insulation)
PRD	pressure relief device

PSTM	point source to tower measurement
PTFE	polytetrafluoroethylene
PVC	polyvinyl chloride

R

RCM	reliability-centered maintenance
RF	radio frequency
RFI	radio-frequency interference
RH	relative humidity
RIV	radio-influence-voltage
RLC	electrical circuit consisting of resistance—R, inductance—L, and capacitance—C
ROHS	reduction of hazardous substances
RR	red rust
RTB	reactor trip breakers
RTD	resistive temperature detector
RTI	relative temperature index
RTV	room temperature vulcanization (silicone)

S

SAE	Society of Automotive Engineers
SAW	surface acoustic wave
SCC	stress-corrosion cracking
SEM	scanning electron microscopy
SHC	synthetic hydrocarbons
SIR	silicon rubber
SS	salt spray (test)

T

TAN	total acid number
TBM	time-based maintenance
TDCG	total dissolved combustible gases
TDS	total dissolved solids
TDS	technical data sheet
TEV	transient earth voltage
THI	transformer health index
TLV	threshold limit value
TPPO	thermoplastic polyolefin (type of cable insulation)
TPR	thermoplastic rubber
TR	temperature rise
TRS	total reduced sulfur
TR-XLPE	tree-retardant cross-linked polyethylene (type of cable insulation)

U–V

UHF	ultra-high frequency
UL	Underwriters Laboratories Inc.
UPS	uninterruptible power supply
URD	underground residential distribution
UV	ultraviolet
VCB	vacuum circuit breakers
VCI	vaporized corrosion inhibitors
VI	viscosity index
VLf	very low frequency
VOC	volatile organic compound
VT	voltage transformer

W–X

WEEE	Waste Electrical and Electronic Equipment
WI	whisker index
WHS	winding hot spot
WR	white rust
WTMS	wireless temperature monitoring system
WWTP	wastewater treatment plant
XLPE	cross-linked polyethylene (type of cable insulation)
XLPO	cross-linked polyolefin (type of cable insulation)
XRD	x-ray diffraction

1 Plating of Electrical Equipment

1.1 ELECTROPLATING FOR CONTACT APPLICATIONS

1.1.1 SILVER PLATING

Silver (Ag) plating has many different uses in an industrial setting. It can be used as an engineering coating owing to its superior conductivity and corrosion resistance. When used in plating, silver's conductivity allows for extensive use in electronics and semiconductor industries. It is also used extensively in the aerospace, telecommunications, military, and automotive industries.

1.1.1.1 Physical Properties of Silver Plating

Silver plating is considered to be one of the most highly conductive plated surfaces. It is widely applied to copper conductors of any kind, including wires.

In electrical power distribution, a bus bar—a thick strip of copper or aluminum—conducts electricity within a switchboard, distribution board, substation, or other electrical apparatus. Bus bars may be connected to each other and to electrical apparatus by bolted or clamp connections. Often, joints between high-current bus sections have matching surfaces that are silver plated to reduce contact resistance (CR).

Offering conductivity and corrosion resistance, silver plating creates a surface that can be soldered and exhibits low electrical resistance. It can be used as engineering coating as well as for bearing surfaces and antigalling applications. Silver plating should conform to Mil QQ-S-365D and ASTM B 700 standards, as well as to ISO 4521, “Metallic Coatings—Electrodeposited Silver and Silver Alloy Coatings for Engineering Purposes.”

Silver resists oxidation by air but is attacked by compounds containing sulfur. Industrial and urban atmospheric environments as well as certain materials contain sulfides. Under these conditions, the tarnishing of silver becomes inevitable. Tarnishing can have various degrees of severity. For more about silver corrosion, see Chapter 3.

Silver and silver-plated components can yellow slightly and sometimes do not discolor any further. The electrical conductivity of silver is not affected by a light yellowing.

In other cases, tarnishing can lead to a dark brown or black color. This discoloration can be partial or total, depending on the conditions of storage or use (finger marks, opened packing, etc.). In addition to aesthetics, the effects of excessive tarnishing at the electric level may be significant (see Section 3.3). Silver sulfides are unstable with a rise in temperature.

Technical characteristics of silver layers:

- Specific electrical resistance: $16\text{--}18.8 \times 10^{-9} \Omega$
- Electrical conductivity: up to $62.5 \times 10^6 \Omega^{-1} \text{ m}^{-1}$ (at 20°C)
- Hardness: 70–160 high voltage (HV)
- Melting point: 960°C
- Coefficient of linear expansion: $19.3 \mu\text{m}^\circ\text{C}^{-1} \text{ m}^{-1}$

1.1.1.2 Silver Plating Thickness for Electrical Applications

The thickness of plating strongly depends on the application and environment to which the silver will be exposed. It was found that at thicknesses $<2 \mu\text{m}$ silver plating is porous and provides no proper protection of base metal from corrosion. For industrial applications, when electrical equipment is serving in a corrosive environment, the thickness of the silver plating should be in the range of $2\text{--}40 \mu\text{m}$. The lowest thickness, $\sim 2 \mu\text{m}$, may be applied only for bolted contacts assembled in a factory and inaccessible to customers. A thin silver plating such as this is usually used in plating copper. For contacts assembled on site, the thickness of the silver plating should be no less than $5 \mu\text{m}$. This is also the minimum thickness of the silver plating on aluminum and aluminum alloys, as well as on ferrous alloys.

1.1.1.3 The Use of a Nickel Underplate for Silver Plating

It is recommended that a nickel underplate (a minimum of $1.25 \mu\text{m}$) be used whenever possible in plating silver. The nature of the tarnish film will change significantly if copper alloy elements from the substrate reach the surface of the silver. This can occur through mechanisms such as diffusion or corrosion creep at breaks in the silver electrodeposit. At higher temperatures, oxygen will diffuse through silver to the copper alloy interface at a relatively high rate and can lead to blistering if no nickel underplate is used. A nickel underplate will also prevent a relatively weak layer of silver–copper intermetallics from forming at temperatures greater than 150°C , which could lead to adhesion problems [1].

In most separable contact interface applications that use a nickel underplate, silver plating thickness is typically in the range of $2 \mu\text{m}$ or greater. What silver thickness is appropriate depends on application factors such as environmental severity, the time at a specific temperature, durability requirements, nickel underplate, and surface treatment. If no nickel underplate is used, a greater thickness of silver may be required to prevent substrate corrosion products from getting to the surface [2]. These higher plating thicknesses also provide more silver material between the atmosphere and the substrate material(s), possibly leading to more wear cycles before any substrate material is exposed.

Silver may be used in plating various base metals. In many cases, the application of underplating prior to plating silver is necessary to provide proper adhesion and corrosion resistivity [3]. Depending on the base metal, different underplating metals should be applied and the thickness of underplating varies (Table 1.1). The data presented in Table 1.1 are a summary of information given in multiple recourses.

On the other hand, constant evolution in a silver plating's appearance is a sign of the presence of sulfur in the immediate vicinity of the electrical apparatus. In

TABLE 1.1
Underplating Types and Thicknesses of silver Platings for Various Base Metals

Base Metal	Underplating Type	Underplating Thickness (μm)
Copper	None	—
Brass (CuZn alloy)	Cu	4
	Ni	5
Bronze (CuSn alloy)	Cu	4
Ferrous alloys	Cu	8
Aluminum and aluminum alloys	Cu ^a	8
	CuSn (bronze) ^b	3
	CuSn	2
	Ni (electroplating)	5
	Ni (electroless)	5

^a Zincade process (be described in more detail in Section 1.6) and plating process consisting of direct deposit of electrolytic bronze and copper developed by PEM in Europe [4].
^b Alstan plating processes (be described in more detail in Section 1.6).

such conditions, antitarnishing treatment of the silver plating is recommended. For electrical applications, only those antitarnishing compounds or techniques which do not contain lacquer and do not experience discoloration should be considered. These compounds should be easily stripped without any damage, should provide antitarnishing protection, and most importantly, must not affect electrical conductivity.

It is important to note that antitarnish and passivation treatments on silver coatings should be compliant with Reduction of Hazardous Substances (RoHS) requirements, which prohibit the use of hexavalent chromium (CrIV). Chromium-free solutions exist and are appropriate for the antitarnish protection/treatment of conductive parts.

1.1.1.4 Types of Silver Platings

ASTM B700 Standard [5] establishes the requirements for electrodeposited silver coatings that may be matte, bright, or semibright finishes. Silver plating is usually employed as a solderable surface and for its electrical contact characteristics, as well as for its high electrical and thermal conductivity, thermocompression bonding, wear resistance on load-bearing surfaces, and spectral reflectivity.

Coatings shall be classified into types according to minimum purity, grade according to surface appearance (bright, semibright, or matte), and class according to whether any surface treatment has been applied. Silver coatings shall undergo preplating operations such as stress relief treatment, strike, and underplating, as well as postplating embrittlement relief.

Silver plating, therefore, may be from white matte to very bright in appearance. Corrosion resistance may depend on the base metal. Hardness varies from about 90 Brinnell to about 135 Brinnell, depending on the process and plating conditions. Solderability is excellent, but decreases with age. Silver plating has excellent lubricity and smear characteristics for antigalling uses on static seals, bushing, and so on.

According to Mil QQ-S-365D Standard, the thickness of silver plating should be no less than $\sim 13 \mu\text{m}$ ($0.0005''$) unless specified otherwise.

Silver is an excellent conductor and is therefore widely used in contacts and joints in switchgear assemblies [6]. Popular methods for silver plating of contact surfaces are electroplating and the dip emersion process. A plating thickness of $5\text{--}15 \mu\text{m}$ is considered adequate for plating a copper or aluminum bus bar. However, a thicker deposit may be needed because of the porosity of silver plating, particularly where environmental conditions may be harsh. For a disconnect switch, plating must be thick enough to prevent exposure of the base metal to contamination, because the joint will be connected and disconnected many times during the service life of the equipment.

There is a serious disadvantage in using silver plating when a connection is made between silver-plated Al or Cu, because silver, like Cu, is cathodic to aluminum, and may cause galvanic corrosion of Al (for more about galvanic corrosion, see Section 2.4).

1.1.2 TIN PLATING

Tin or tin alloy coating is a cost effective and reliable alternative to noble metal finishes (gold, silver) thanks to tin's low cost, low contact resistance (CR), and good solderability.

1.1.2.1 Physical Properties of Tin Plating

The following standards define the tin plating intended for engineering purposes: Mil-T-10727C, "Tin," and ASTM B-545, "Standard Specification for Electro-Deposited Coatings of Tin," and Standard ISO 2093-1987, "Specifications and Test Methods for Tin Electroplated Coatings." Tin plating is used for corrosion protection, to facilitate soldering, and to improve antigalling characteristics. Copper alloys containing more than 5% Zn should have a copper or nickel underplating.

According to Tin Military Standard Mil-T-10727C, there are two types of tin plating: Type I—Electrodeposited plating and Type II—Hot dipped plating. Plating color is gray-white in plated conditions; it is soft but very ductile. Corrosion resistance is good (coated items should meet 24 h 20% salt spray (SS) requirement). Tin is not suitable for low-temperature applications, it changes structure and loses adhesion when exposed to temperatures below -40°C (-40°F).

However, the use of tin plating is limited by tin's low durability characteristics and susceptibility to fretting corrosion, which will be discussed in Section 2.5. These limitations may be avoided by using tin plating only in applications where a relatively low number of mating cycles are required, and by using appropriate contact design and lubrication (as needed) to reduce susceptibility to fretting corrosion.

Technical characteristics of tin layers:

- Hardness: 20–27 HV
- Melting point: $205\text{--}232^\circ\text{C}$
- Specific electrical resistance: $115 \times 10^{-9} \Omega$
- Coefficient of linear expansion: $17\text{--}27 \mu\text{m}^\circ\text{C}^{-1}\text{m}^{-1}$
- Electrical conductivity: up to $8.7 \times 10^6 \Omega^{-1}\text{m}^{-1}$ (at 20°C)

TABLE 1.2
Tin Plating Techniques for Electrical Applications

Base Metal	Plating Technique	Underplating Type	Underplating Thickness (μm)
Copper	Matte, bright, or bright hot-dipped	None	—
Copper–zinc alloys (brass)	Same	Ni or Cu	2.5–4
Copper–tin (bronze)	Same	Cu	4
Copper–aluminum alloys	Same	Cu	4
Aluminum and aluminum alloys	Zincate ^a	Cu	8
	Alstan ^b	CuSn bronze	3
	PEM process ^c	CuSn bronze and Cu	2
			8
	Ni underplating	Ni	5 ^c
Ferrous alloys		Cu	8

^a These techniques will be presented in more detail in Section 1.6.3.
^b Plating process consisting of direct deposit of electrolytic bronze and copper developed by PEM in Europe [2].
^c While plating tin on aluminum base, Ni underplating should not exceed 10 μm in order to avoid increases in CR, so usually it is recommended to be not more than 5 μm for electrical engineering applications.

From July 1, 2006, the implementation of the RoHS directive, which bans lead in products, requires using RoHS-compliant components. Some component manufacturers already propose that pure tin (or high-tin-content) surface finishes replace Sn-containing lead (Pb). These finishes present a major reliability risk which can reduce their use because pure tin plating is prone to tin whiskers (tiny tin filaments that may cause short circuits). The effect of RoHS compliance on the tin whiskers phenomenon will be discussed in Section 1.5.

Table 1.2 shows acceptable techniques and types of underplating for the better adherence of tin plating for electrical applications.

For electronic components, such as connectors, various types of tin plating are used: matte Sn and SnCu, bright Sn, and hot dipped Sn and SnCu, all usually with Ni underplating. Electronic components with a lead frame are plated with matte Sn alloys either with 2–4% of Bi or with 1.5–4% of Ag. Tin plating could be applied with or without underplating. However, when tin plating is applied to electronic components without a lead frame, Ni underplating is used, and “post-baking,” or postplating annealing at 150°C for 1 h, is recommended. Other types of platings used for electronic components are hot dipped Sn, SnAg, SnCu, and reflowed tin.

1.1.2.2 Tin Plating Thickness for Electrical Applications

Tin plating thickness depends on which base metal tin is going to be deposited. Tin electroplating on copper is recommended to be not less than 5 μm, and tin

TABLE 1.3
Minimal Thicknesses of Tin Platings for Electrical Applications

Environment	Min. Thickness (μm) (Base Metal Contains Cu)	Min. Tin Thickness (μm) (Other Base Metals)
Indoor, dry atmosphere	5	5
Indoor, with condensation	10	12
Outdoor, extreme T	15	20
Outdoor, corrosive	30	30

Source: Multiple industrial and OEMs Plating Standards.

TABLE 1.4
Properties of Some Sn–Pb Substitute Platings

Property	SnCu	SnAg	SnBi
Electrical resistance	Fair	Fair	Fair
Anticorrosion	Good	Good	Good
Antifretting	Fair	Fair	Fair
Antitin pest	Fair	Good	Good
Antiwhiskers	Fair	Good	Good

electroplating on aluminum is recommended to be at least 8 μm (Table 1.3). The specifics of tin plating on Al will be discussed later in Section 1.6.

To comply with the requirements of the European directive 2002/95/CE (RoHS directive) of the European Parliament and the European Union Council of January 27, 2003 regarding the restriction of hazardous substances in electric and electronic equipment and, in particular, regarding lead substitution in tin–lead coatings, some substitute lead-free tin alloy platings may be considered for electrical applications. Among those are tin–bismuth alloy (SnBi), tin–copper alloy (SnCu), and tin–silver alloy (SnAg). Pure tin (matte or bright), as well as silver or nickel plating, may also be used as substitutes; however, the use of pure tin plating does not provide protection from tin whisker growth and fretting corrosion. Some properties of tin alloy platings, the substitute for tin–lead, are shown in Table 1.4 (for more about fretting corrosion and tin pest, see Chapter 2).

1.1.3 NICKEL PLATING

Electroplated Ni is not traditionally used in plating conductive parts of electrical equipment; more often, it is applied as an undercoating for other metals such as gold, tin, or palladium. It acts as a barrier layer to prevent the diffusion of the base metal to the surface. In the case of tin-coated contacts, it prevents the formation of copper–tin intermetallics (discussed in Sections 2.2 and 2.3). Nickel plating passivates pores and bare edges, reducing the potential for pore corrosion and creep corrosion.

1.1.3.1 Applications of Nickel Plating in the Electrical Industry

There are some special applications of nickel plating, such as for the aluminum used for electrical products such as wires, cables, or terminal connectors. In some industrial applications, the surface of the metal has to be modified in order to promote a good and durable electrical contact. This is particularly the case for the aerospace industry, where nickel electroplating on aluminum has proved to be a good means of significantly improving the surface conductivity of the substrate.

However, traditional processes of nickel plating on aluminum are complex to achieve as they require chemical pretreatments and several sublayers. That is why an original direct nickel electroplating method has been developed, which requires only two steps to cover the substrate. The resulting nickel layer not only exhibits a good adhesion, but also allows meeting specifications in terms of electrical contact [7,8]. It was also shown that a nickel plating layer is stable up to high working temperatures (about 400°C) [7]. In studies of the effect of fretting in the contact properties of nickel-plated aluminum, it was shown that contact zones are considerably degraded by fretting, which could be mitigated with the application of lubricants and by using heavier loads [9,10].

Nickel plating was tested for copper bus bars bolted to aluminum [11], and demonstrated an excellent stability and low initial CR. As proved in Ref. [12], nickel plating on copper-to-aluminum connections provides a better performance than silver- and tin-plated connections under different operating and environmental conditions. Nickel can be directly plated over several metals, typically steel, brass, and copper. In some cycles, appropriate immersion treatments or preplate deposits precede nickel. Aluminum, because of its unique electropositive nature, must first be conditioned by immersion zincating before plating either electrolytic or electroless nickel (EN).

1.1.3.2 Physical Properties and Thickness of Nickel Plating

Properties of nickel electrodeposited plating are defined in Federal Specifications QQ-N-290A (1997) [13] and SAE AMS-QQ-N-290 (2000) [14], which cover the requirements for electrodeposited nickel plating on steel, copper and copper alloys, and zinc and zinc alloys. Electrodeposited nickel plating covered by these specifications is determined to be one of the following two classes: Class 1—Corrosion protective plating and Class 2—Engineering plating.

Class 1 plating is divided into seven different grades with different thicknesses, from Class A with the thickest plating (40 μm) to Class G with the thinnest coating (3 μm). According to these specifications, Class 1 plating shall be applied on a plating of copper on steels, and on copper and copper-based alloys (Table 1.5). Class 1 plating shall be applied to an underplating of copper or yellow brass on zinc and zinc-based alloys. Copper alloys containing zinc equal to or greater than 40% shall have a copper underplate of $\sim 7.5 \mu\text{m}$ (0.0003 in.) minimum thickness.

Class 1 has three processing grades: SB—single-layer coating in a fully bright finish; SD—single-layer coating in a dull or semibright finish, containing $<0.005\%$ sulfur and having an elongation greater than 8%; and M—multilayer coating, either double layer or triple layer. When applied on copper and copper alloys, electrodeposited nickel plating with a thickness of 5–20 μm protects the base metal from

TABLE 1.5
Minimum Thicknesses of Class 1 Nickel Plating on Copper and Copper Alloys

Coating Grade	Ni Thickness (μm)	Coating Grade	Ni Thickness (μm)
A	40	E	10
B	25	F	5
C	20	G	3
D	15		

Sources: From Ni Plating Federal Specifications QQ-N-290A (1997), SAE AMS-QQ-N-290 (2000), and Aerospace Material Specification/Nickel Plating (Electrodeposited) AMS-QQ-N-290.

corrosion in indoor and outdoor environments; the same protection of aluminum and aluminum alloys is provided by electrodeposited nickel plating with a thickness of 10–30 μm. On aluminum and aluminum alloys, an immersion plating of zinc or tin and electrodeposited copper and other undercoatings are recommended in order to guarantee adhesion before the application of nickel coating.

Electroplated nickel is often used in plating copper conductors. There are multiple standards which define the thickness of nickel plating on copper conductors, depending on the diameter of the conductors, such as ASTM B 3, ASTM B 5, ASTM B 170, ASTM B 286, ASTM B 355, MIL-W-16878, MIL-W-22759, MIL-W-27038, and so on.

Nickel-plated copper has wide applications in aircraft wiring for special wind and moisture problem areas, as well as for aircraft engine and fire zone safety wiring, automotive engine and exhaust monitoring, high-temperature industrial and home appliances, electronic components, electric furnaces, heat tracing wiring, and down-hole oil logging.

Nickel-plated copper combines the desired features of both metals: the 100% IACS conductivity of copper necessary for efficient electrical and thermal energy transfer, and the high-temperature stability and corrosion resistance provided by nickel. Bare (unplated) copper conductors are generally rated for military applications operating at up to 105°C. Above this temperature, bare copper will oxidize excessively, become brittle and less ductile, and lose conductivity. Various plating thicknesses of nickel increase the useful continuous operating temperature of the plated copper conductor to as high as 450°C (842°F) [15].

1.2 ELECTROLESS PLATING

Electroless plating is a process for chemically applying metallic deposits onto substrates using an autocatalytic immersion process without the use of electrical current. It differs from electroplating, which depends on an external source of direct electrical current to produce a deposit on the substrate material. Since electrical current cannot be distributed evenly throughout the component, it is very difficult to obtain uniform coatings with electrolytically applied deposits. Electroless deposits, therefore, are not subject to the uniformity problems associated with electroplated coatings.

EN is one of the most used plating materials in the electronic and electrical industries. Major industry specifications for EN are AMS 2404, “Electroless Nickel Plating”; AMS 2405, “EN, Low-Phosphorus”; ASTM B656, “Guide for Autocatalytic Nickel-Phosphorus Deposition on Metals for Engineering Use”; ASTM B733, “Standard Specification for the Autocatalytic Nickel-Phosphorus Coatings on Metal Coatings”; and so on.

1.2.1 ELECTROLESS NICKEL: PHYSICAL PROPERTIES

EN can be applied with excellent adhesion to many different substrates: steels, stainless steels, aluminum, copper, bronze, and brass.

Deposits may contain different amounts of phosphorus or boron depending on the chemicals in the autocatalytic process. The microstructure of an EN-phosphorus deposit strongly depends upon the alloy content of the deposit.

1.2.1.1 Chemical Composition and Structure of EN Plating

Various EN systems with phosphorus are formulated to co-deposit from 1% to 13% phosphorus. The phosphorus content in the alloy is the most significant parameter to control the properties of plating. Generally, as plated, the higher phosphorus (above 9%) alloy deposits are often softer and tend to be nonmagnetic. Phosphorus levels can vary, ranging from 3% to 12% by weight. The industry identifies EN coatings according to their phosphorus content, for example:

- Low-phosphorus EN: 1–3%
- Low–medium phosphorus: 4–6%
- Medium-phosphorus EN: 7–9%
- High-phosphorus EN: 10–13%

At low and medium phosphorus levels ($<7\%$ by weight), the EN deposit is microcrystalline, consisting of many small grains, $\sim 2\text{--}6$ nm in size. As the amount of alloyed phosphorus increases, the microstructure changes to a mixture of amorphous and microcrystalline phases and finally to a totally amorphous phase ($>10\%$ by weight).

1.2.1.2 Physical Properties of Electroless Ni Plating

When using EN in electrical applications it is important to remember that its physical properties, such as hardness, electrical resistance, and corrosion resistance, are related to the plating composition.

1.2.1.2.1 Hardness

The *hardness* of an EN deposit is inversely related to its phosphorus content. As the phosphorus content increases, the as-plated hardness decreases. In all cases, EN deposits can be hardened through heat treatment, which causes the formation and precipitation of nickel phosphide (Ni_3P). Typical heat treatment conditions for full hardness are 400°C (752°F) for 1 h in an inert atmosphere. If there is no access to an inert atmosphere oven and discoloration is objectionable, or there is a need to

TABLE 1.6
Physical Properties of EN Plating with Phosphorus

Property	Low Phosphorus, 1–3% P	Low–Medium Phosphorus, 4–6% P	Medium Phosphorus, 7–9% P	High Phosphorus, 10–13% P
Deposit density range (g/cm ³)	8.6–8.8	8.3–8.5	8.0–8.2	7.6–7.9
Hardness as plated (HK ₁₀₀)	725–800	625–750	500–600	450–425
Hardness after heat treatment (HK ₁₀₀)	900–1100	850–1100	850–1000	850–950
Coefficient of thermal expansion (mμ/m °C)	12–15	11–14	10–15	8–10
Electrical resistivity (μΩ cm)	10–30	15–45	40–70	75–110
Thermal conductivity (W m · K ⁻¹)	6.28	6.70	5.02	4.19
Tensile strength (MPa)	200–400	350–600	800–1000	650–900
Elongation (%)	0.5–1.5	0.5–1	0.5–1	1–2.5
Melting range (°C)	1250–1360	1100–1300	880–980	880–900

Source: Based on data from “Electroless Nickel Plating” by Mike Barnstead and Boules Morcos. <http://www.pfonline.com/articles/electroless-nickel-plating>.

harden without affecting the hardness of the substrate, full hardness can be obtained at lower temperatures with longer times.

1.2.1.2.2 Wear Resistance

EN coatings have good *wear resistance* because of their high hardness and natural lubricity. This, coupled with the uniformity of the EN deposit, makes it an ideal wear surface in many sliding wear applications. Relatively soft substrates with poor abrasion resistance, such as aluminum, can be given a hard, wear-resistant surface with EN. EN has also found widespread use in antigalling applications, where the use of certain desirable materials could not otherwise be used due to their mutual solubility and propensity to gall and seize. A deposit’s hardness can be increased through heat treatment to further enhance wear properties, rivaling the wear properties of hard chromium.

All the physical properties of electroless Ni (EN) depend on the amount of phosphorus or boron in the deposit (density, hardness, corrosion resistance, etc.) [16–19]. Some physical properties of EN with phosphorus are shown in Table 1.6.

1.2.1.3 EN Film Thickness

Another important parameter which significantly influences the properties of the deposited film is the thickness of the film. One particularly beneficial property of EN is its uniform coating thickness, which can affect the ultimate performance of the coating and can also eliminate additional finishing after plating.

With electroplated coatings, the thickness can vary significantly depending upon the part’s configuration and its proximity to the anodes. With EN, the coating

thickness is the same on any section of the part exposed to a fresh plating solution, and can be controlled to suit the application. Grooves, slots, blind holes, and even the inside of the tubing will have the same amount of coating as the outside part.

1.2.2 ELECTROLESS NICKEL: CORROSION RESISTANCE

A very important property of EN plating is its strong corrosion resistance, which makes it a very attractive plating for use in the electrical industry for equipment exposed to corrosion. Corrosion resistance of EN is stronger for coatings with a higher content of phosphorus, based on the amount of time before the first signs of corrosion appear after the exposure of plating to salt spray (SS) (Table 1.7).

Optimizing film thickness will control corrosion resistance in engineering applications. ASTM B733 specifies the thickness of the Ni alloy film depending on the service condition, which can vary from 60 μm (2.4 mil or 0.0024”) for very severe conditions to 5 μm (0.2 mil or 0.0002”) for mild ones.

In general, choosing a proper composition and thickness of the coating will control its corrosion resistance. Corrosion properties of electroless coatings depend not only on the thickness of the film and its nonmetal content [20,21], but also on different parameters characterizing the process of plating, such as the coating time [22], solution age [23], and heat treatment [21].

1.2.3 ELECTROLESS NICKEL: ELECTRICAL RESISTIVITY

The use of electroless Ni in the electrical industry for application to electrical conductors strongly depends on the electrical resistivity of EN. Pure metallurgical nickel electrical resistivity is about 6.05 μΩ-cm. The electrical properties of electroless coatings vary with the plating composition. It is very important for EN alloy films deposited on the contact surface to have a *low electrical resistivity*.

For high-phosphorus deposits, coatings are significantly less conductive than conventional conductors such as copper. EN deposits containing 6–7% of P have resistivity in the range of 52–68 μΩ-cm. When P content is about 13%, the electrical

TABLE 1.7
Hours to First Appearance of Rust Pit for EN Plating with Different Phosphorus Contents

Thickness of Coating (μm) (Mils)	Low-Medium Phosphorus, 4–5% P	Medium Phosphorus, 6.5–8% P	High Phosphorus, 10–12% P
12.7 (0.50)	24	24	250
22.4 (0.88)	96	96	1000
38.6 (1.52)	96	96	1000
50.8 (2.00)	96	96	1000

Source: Based on data from ASTM Standard B117 SS Test.

resistivity is $110 \mu\Omega\text{-cm}$. Heat treatment of EN reduces its electrical resistivity [22]. Alloying elements such as phosphorus as well as the presence of amorphous phases increase the electrical resistivity of the deposit.

For low-phosphorus deposits containing 2.2% P, the electrical resistivity is about $30 \mu\Omega\text{-cm}$. It was found [24–26] that nickel alloys containing <2 at% of P are the most promising contact materials for replacing precious metals. Nickel alloy deposits with a minimum thickness of $2.5 \mu\text{m}$ exhibit a favorably low CR ($2\text{--}7 \mu\Omega$) after exposure to several accelerated environmental tests [20].

Because of the relatively thin layers used, however, for most applications, the resistance of EN is not significant. Heat treatments precipitate phosphorus from the alloy and can increase the conductivity of EN by two to four times. The formulation of the plating solution can also affect conductivity. EN with boron yields the lowest resistivity of any commercial EN type. Phosphorus content also has a strong effect on the thermal expansion of EN.

Because of their electrical and magnetic properties, electroless Ni (EN) alloys are widely used by the electronic industry for a variety of functions [26,27]. For electronic components, EN is used for its combination of superior corrosion resistance and solderability.

Other important considerations with these components are the coating's uniform thickness and its consistent electrical, thermal, and physical properties. Coaxial connectors, headers, housings and cases, heat sinks, diode cans, shutters, interlocks, and memory disks and drums are among the many electronic applications currently plated with EN.

The major high-volume component plated is the aluminum memory disk found in many computer storage devices. It consumes a huge amount of EN. The high-phosphorus EN used in this application has to be exceptionally smooth and nonmagnetic to serve as a base for the subsequent magnetic layers.

Another large electronic application is the coating of both aluminum and zinc connectors. Here, the coating serves to provide corrosion protection and wear resistance and is especially important because of the complex shape of these components. These are for both commercial and military uses.

1.3 ELECTROLESS NICKEL AS A PLATING ALTERNATIVE FOR ELECTRICAL APPARATUSES IN CORROSIVE ATMOSPHERE

The coating deposited on the surface of copper parts of electrical contacts must display two important properties. First, it must withstand a harsh environment—mostly high humidity and a high concentration of hydrogen sulfide, chlorine, and/or other corrosive gases and particles in the air. This specific environment is generally typical of wastewater or sewage treatment plants. Hydrogen sulfide is also widely used in metallurgy, paper mills, at phosphorus mills and plants, and in the process of producing oil additives and other chemicals.

For electrical connectors working in areas with harmful atmospheric components (chlorine, hydrogen sulfide, chloric and sulfuric acid vapors, water vapor, salts, etc.), the use of silver and tin is often unacceptable. These coating materials corrode very

quickly, leaving base metals unprotected. In a harsh environment, a different type of plating which can better withstand a high concentration of corrosive gases and vapors may be used.

For electrical applications, circuit breaker (CB) primary parts/disconnects/stabs and low-voltage (LV) buses need to be plated with the plating that will protect current-carrying parts from resistance deterioration in a heavy corrosive industrial environment. Such a plating with high corrosion resistance must have a relatively low electrical resistance in order to successfully compete with the silver and tin plating traditionally used in finishing the conductive parts of electrical apparatus.

EN may be considered as an alternative plating for current-carrying parts in some specific applications, because some formulations of EN have a relatively low electrical resistance and at the same time provide excellent corrosion protection. However, the application of EN plating to electrical conductive parts requires careful and thorough testing.

1.3.1 TESTING OF EN FOR USE IN ELECTRICAL APPLICATIONS

Testing the possibility of applying electroless Ni to current-carrying parts of a specific electrical equipment is needed to verify that the anticorrosion properties of EN are superior to that of various traditional electroplating types (silver and tin) in identical conditions. It must also be determined whether the electrical resistance of EN plating is comparable to traditional silver and tin plating.

If testing confirms that EN plating provides not only its already well-known perfect anticorrosion protection, but also an acceptable electrical resistance in specific electrical applications, then it becomes necessary to run field testing of EN-plated electrical equipment in energized conditions exposed to industrial corrosive environments for extended periods of time. This testing will allow, if successful, the possibility of using EN as an alternative plating for the corrosion protection of current-carrying parts of specific electrical apparatus.

1.3.1.1 Testing the Anticorrosion Properties of EN Plating

The best way to test the anticorrosion properties of EN plating and compare these properties with those of traditional electroplating is to run a test using identical copper coupons in identical laboratory conditions. To receive statistically reliable results, three coupons were plated with one of five platings of interest: two EN platings with different phosphorus contents and three traditional electroplatings: silver (Ag), tin (Sn), and nickel (Ni). Three coupons were left unplated (bare copper). In as-plated coupons, the amount of deposited metal (Sn, Ag, Ni, or Ni-P alloys) in each plating before the corrosion test was 100 at%, as determined using an x-ray elemental analysis.

The corrosive effect of environmental gases is strongly enhanced by other environmental parameters such as high humidity and high ambient temperature, which altogether rapidly destroy the integrity of metal finishes and produce extremely heavy tarnish films on some base-metal surfaces. Conditions of corrosion testing were designed to represent an atmospheric environment similar to the one which causes failures in CB service conditions. These conditions include a gaseous mixture

of air with H_2S and water vapor. Another predefined condition was elevated temperature. According to many reviews, the most concentrated corrosive environment among all industries has been observed at waste water treatment plants and older paper mills. The choice of corrosion test conditions has been based on standards that define the limit of corrosive gases concentration in the environment of such industrial sites.

The Occupational Safety and Health Administration (OSHA), the American Conference of Governmental Industrial Hygienists (ACGIH), and the National Institute for Occupational Safety and Health (NIOSH) Standards describe environments that could be observed at paper or sewage-treatment plants both indoors and outdoors [28–30]. The OSHA ceiling for H_2S is 20 ppm, and the peak is 50 ppm for 10 min. The NIOSH ceiling for H_2S is 10 ppm for 10 min, and evacuation is over 65 ppm. The ACGIH Standard defines threshold limit value (TLV) and the concentration which could be “immediately dangerous to life or health” (IDLH), and represents the maximum level from which one could safely escape within 30 min) for H_2S equal to 300 ppm. For the pulp and paper industry, total reduced sulfur (TRS) levels, including H_2S and elemental sulfur vapor, vary considerably for each point source and are related to the age of the mill [31].

Newer paper mills with efficient recovery boilers typically produce TRS levels of <20 ppm. At some older Kraft mills, TRS levels approaching 2000 ppm have been observed. Hydrogen sulfide levels in the vapor above the condensate were found to be 450 ppm at some paper mills. H_2S could also be liberated from the sludge at the presses, with H_2S levels from 40 to 100 ppm. However, levels spike to 750 ppm, depending on throughput volumes and feed composition. Besides, according to Ref. [30], the actual changes in concentration from outdoors to indoors are really not that significant, amounting to an average decrease of <50% for reduced sulfur.

Based on definitions from these tests, the following conditions for corrosion tests have been selected: H_2S concentration—2000 ppm; relative humidity—100%, temperature—40°C (104°F) (highest indoor possible); test duration—30 days. These conditions are much more severe than the conditions of a Class IV environment, according to the classification system developed at the Battelle Institute in Columbus, OH, for mixed flowing gas (MFG) testing conditions. Class IV represents the most severe level of corrosive environment [32,33] with T at 40°C (104°F), relative humidity (RH) 75%, and H_2S level at 200 ppb (compared with 2000 ppm in our test, which is 10,000 times higher). Exposure time (30 days) is also longer than specified for MGF testing (20 days). The corrosion test was run in a 4-L heated kettle which served as the test chamber; the coupons were hung in the kettle’s upper portion. The kettle was partially filled with deionized water through which a mixture of 2000 ppm of H_2S with air was continuously bubbled at a slow rate while the water temperature was maintained at about 43°C (110°F). Thus, the coupons were exposed to 2000 ppm of H_2S environment that was nearly saturated with water vapor.

After the 30-day exposure, the samples were removed, washed with deionized water, air dried, and examined visually for scaling, discoloration, and other signs of corrosion attack. The coupons of bare copper and tin-plated coupons were covered with heavy black scale. The silver plating was heavily tarnished. Pure Ni-electroplated coupons had dull luster with slight tarnish from some filming.

The best in appearance were the coupons plated with EN plating—they still had a bright luster with a slight tint and no apparent scaling.

Further analysis included elemental composition of the surface/deposits, morphology of the plated surfaces (microphotographs of the cross section of the coupons) and microphotographs of the surface at different magnifications using the scanning electron microscopy (SEM)/energy-dispersive x-ray spectroscopy (EDS) technique. The chemical composition of the deposits after the corrosion test helped to determine which corrosion products were formed on the surface. The result of the elemental analysis of the surfaces of the coupons with two different pure metal electroplatings (silver and tin) is compared with the corroded bare copper coupon, as shown in [Table 1.8](#).

From the visual appearance of the surfaces, tin plating is almost entirely destroyed, and chemical data show that the black scale on the surfaces consists of copper oxides and sulfides. The silver plating after the corrosion test is also heavily damaged, with less than 15% of silver plating remaining; in some spots there is up to 30% silver in the form of oxides and sulfides. Both silver and tin plating had significant corrosion products on the surface with discontinuous plating observed in the microphotographs of the sample cross section. Very unusual formations covering the surface were found on the surface of silver-plated coupons ([Figure 1.1](#)). Based on chemical analysis of the “Corrosion Sunflower,” no silver is present in the “flower”—only copper, oxygen, and sulfur. Microphotographs of cross-sections of both silver and tin platings show discontinuity, or even complete loss, of the plating.

Compositions of the corroded coupon surfaces plated with two different EN plating compositions (1) and (2) and Ni electroplating are shown in [Table 1.9](#).

The coupons with pure electrolytic Ni and one EN plating type did not show any damage or inclusions after the corrosion test, and one EN plating type was found partially oxidized.

According to the results of the corrosion test, the electroplated nickel and EN-plated coupons showed much better corrosion resistance, with less corrosion product formed on the surface than for traditional silver and tin electroplating. This corrosion test confirmed that EN plating withstands a very concentrated corrosive atmosphere much better than traditional silver and tin plating, which are virtually destroyed during corrosion tests.

It is important to note that the results obtained in the corrosion test characterize the corrosion resistance of the plating in predetermined conditions in a specific accelerated test. Also, the compositions of the coupon surfaces present the range of composition of the surface layer rather than its exact composition. The area of the spot under the electronic beam is very small (from 1 to 100 μm^2), and the relative composition of the film at this spot strongly depends on the set of elements which are covering this tiny part of the surface. This composition varies in a very wide range at different spots. Analytical data may vary in different measurements, and also depend on experimental conditions.

These data provide an overall picture of a sulfuric environment's effect on silver, tin, and nickel platings and compare their corrosion resistance with that of EN alloy plating. However, the results of the corrosion test do not necessarily correlate directly with the actual corrosion resistance of each plating material tested in a sulfide-rich environment. It is very important to consider plating quality, such as porosity and the continuity of the plating, as well as the specific surface treatment of

TABLE 1.8**Surface Compositions of Copper Coupons with Electrolytic Tin, Silver, and Nickel Plating before and after Corrosion Tests**

Corrosion Test	Cu, at%		Ag, at%		Sn, at%		Ni, at%		O, S, at%	
	Before	After	Before	After	Before	After	Before	After	Before	After
Ag plating	0	70–83	100	29–15	—	—			0	1–2
Sn plating	0	0	—	—	100	78–81			0	21–17
Ni plating	0	0	—	—			100	100	0	0
Bare copper	100	90	—	—	—	—			0	10

Source: Modified from Chudnovsky, B.H. Degradation of power contacts in industrial atmosphere: Plating alternatives for silver and tin, *Proceedings of the 49th IEEE Holm Conference on Electrical Contacts*, pp. 98–106, 2003. © 2003, IEEE.



FIGURE 1.1 Sulfide-oxide “flowers” made of Cu, O, and S (×8000) cover the surfaces of silver-plated copper coupons after corrosion test.

TABLE 1.9
Surface Compositions of Copper Coupons with Electroless Ni (EN) Plating before and after Corrosion Test

Corrosion Test	Ni-P Alloy, at%		O, at%	
	Before	After	Before	After
EN(1) plating	100	93–94	0	7–6
EN(2) plating	100	100		

Source: Modified from Chudnovsky, B.H. Degradation of power contacts in industrial atmosphere: Plating alternatives for silver and tin, *Proceedings of the 49th IEEE Holm Conference on Electrical Contacts*, pp. 98–106, 2003. © 2003, IEEE.

the base material, which, in addition to the chemical nature of the plating, may also contribute to corrosion resistance.

1.3.1.2 Testing of the Electrical Properties of EN Plating

In general, EN is not universally superior to silver or tin. EN plating has a significantly higher electrical resistance than traditional silver and tin plating. Therefore, when in electrical applications EN plating is considered as an alternative plating for electrical current-carrying parts, it is essential to confirm that EN-plated equipment could be applied at the same rate as originally designed by the original equipment manufacturer (OEM).

There are several electrical tests designed to measure electrical resistance of electrical conductive parts according to the American National Standards Institute (ANSI) Standards. One of the most important tests is the continuous current test (CCT) setup for CBs in accordance with ANSI Standard C37.09-1979, Section 4.4.

TABLE 1.10
Resistance Rise on Energized Electrical Contacts with Five Various Platings and Bare Copper during CCT

ΔR (m Ω)	Cu	Ag	Sn	Ni	EN1	EN2
Cold contacts	40	38	40	42	44	43
Hot contacts	40	40	41	53	55	43

Source: Modified from Chudnovsky, B.H. Degradation of power contacts in industrial atmosphere: Plating alternatives for silver and tin, *Proceedings of the 49th IEEE Holm Conference on Electrical Contacts*, pp. 98–106, 2003. © 2003, IEEE.

Therefore, prior to using EN plating in refurbished electrical equipment it is strongly recommended that a series of life tests be performed, including a CCT.

CCT was run on equipment specifically designed for such a testing: six manufactured model sets made of copper bus bars with bolted connections to test the electrical resistance of current-carrying parts coated with the same plating types, which have been tested for corrosion resistance. Each model set was plated with one of five different finishes: two compositions of EN plating, one with a low content of phosphorus (LPEN) and another with high content of phosphorus (HPEN), and three traditional electroplatings (silver, tin, and nickel), with one set left with no plating (bare Cu). A model set of parts was designed to fit the CCT setup for CBs in accordance with ANSI Standard C37.09-1979, Section 1.4.4. CCT was performed on each of the six model sets of copper parts, plated or bare, assembled, enclosed in a cardboard box and connected to a power supply.

According to the test conditions, resistance (R) was measured on two pairs of contacts (upper and lower) twice, at the beginning and at the end of each test at 1600 A. The ambient temperature (T) and contact temperature were measured every half an hour, as well as R cold (CR before the test) and R hot (CR measured at the end of the test). Resistance rise (ΔR) was calculated as the difference between these two values. Resistance rise for various platings during the CCT is shown in Table 1.10.

The temperature rise (the difference between the ambient temperature and the temperature of the contact) for various platings and bare copper after 0.5, 2.5, and 5 h in energized conditions is shown in Table 1.11.

The result of the tests shows that neither the electrical resistance rise nor the temperature rise (TR) for EN-plated contacts is significantly higher than these values for traditional plating.

**1.3.2 FIELD TESTING OF EN-PLATED ELECTRICAL EQUIPMENT
IN ENERGIZED CONDITIONS**

Two previous tests proved that an EN plating of a carefully chosen formulation and thickness may offer not only the best anticorrosive properties, but also a relatively low electrical resistance, not significantly exceeding the resistance of the best conductive

TABLE 1.11
Temperature Rise on Energized Electrical Contacts with Five Various Platings and Bare Copper during CCT

Time in Energized Condition (h)	Bare Cu ΔT (°C)	Ag ΔT (°C)	Sn ΔT (°C)	Ni ΔT (°C)	EN1 ΔT (°C)	EN2 ΔT (°C)
0.5	0	0	0	0	0	0
2.5	103	85	90	84	90	96
5.0	110	92	96	92	92	96

Source: Modified from Chudnovsky, B.H. Degradation of power contacts in industrial atmosphere: Plating alternatives for silver and tin, *Proceedings of the 49th IEEE Holm Conference on Electrical Contacts*, pp. 98–106, 2003. © 2003, IEEE.

platings such as silver and tin. EN’s inherent hardness means that it does not require additional hardness treatments. The combination of these properties could make EN plating a good alternative to traditional plating for the electrical connectors of CBs exposed to corrosive atmospheres.

The last stage of the testing should provide proof that the real electrical apparatus’ current-carrying parts coated with EN plating will properly function while being exposed to extreme corrosive conditions without the extensive deterioration of electrical resistance and failure.

The industrial environment of a wastewater treatment plant (WWTP) has been chosen as a testing site for the third stage of EN testing. As the electrical unit for the field test, a medium voltage (MV) electrical apparatus (MV electrical contactor) was chosen for reconditioning with EN plating after serving for a relatively short period of time at the same WWTP in heavily corroded conditions. The original (“as-is”) condition of the unit after serving for a relatively short time at WWTP is easily seen in [Figure 1.2](#). The contacts of the contactor are covered with heavy black scale, which previously was silver plating.

1.3.2.1 Live Electrical Tests

According to the industry standards, there are several tests for determining the condition of electrical apparatuses. One of the tests is the high potential (Hipot or HP) test to measure the quality of insulation between electrical parts; this test is also called the dielectric withstanding voltage (DWV) test. The theory behind the test is that if a deliberate over-application of test voltage does not cause the insulation to break down, the product will be safe to use under normal operating conditions—hence the name dielectric withstanding voltage test. This test is helpful in finding nicked or crushed insulation, stray wire strands or braided shielding, conductive or corrosive contaminants around the conductors, terminal spacing problems, and so on.

The setup and test guidelines of the HP test are defined in IEC Standard 61010, “Safety Requirements for Electrical Equipment for Measurement, Control, and Laboratory Use,” and in the Underwriters Laboratories Inc. (UL) Standard 61010A-1,

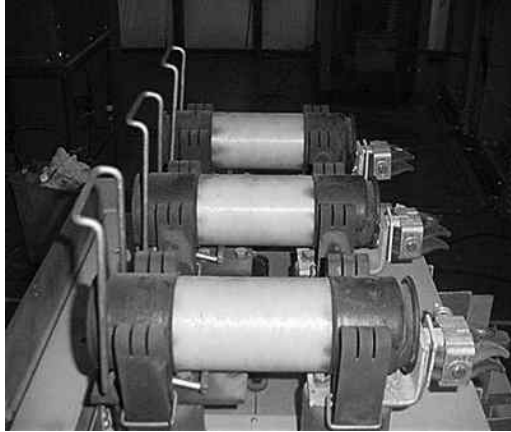


FIGURE 1.2 Heavily corroded electrical contacts of MV contactor after being exposed to the corrosive atmosphere of a WWTP.

“Electrical Equipment for Measurement, Control, and Laboratory Use; Part 1: General Requirements.”

This test is usually applied to verify that the insulation of a product or component is sufficient to protect the operator from electrical shock. In a typical HP test, HV is applied between a product’s current-carrying conductors and its metallic shielding. The resulting current that flows through the insulation, known as leakage current, is monitored by the Hipot tester.

The *insulation resistance (IR) test* is used to provide a quantifiable resistance value for all of a product’s insulation. The test voltage is applied in the same manner as in a standard Hipot test, but is specified to be direct current (DC). The voltage and measured current value are used to calculate the resistance of the insulation. According to the requirements, the contactor in “as-is” conditions was thoroughly tested.

The *HP test* was performed with the contactor in the closed position, a phase-to-ground and phase-to-phase for each pole. The contactor should sustain test voltage for 1 min. Before and after the Hipot test, *IR* was measured and recorded at DC in closed position between phase-to-ground and phase-to-phase.

The contactor also passed through the CCT, in which temperature was measured with thermocouples installed at all significant points along the current-carrying path. CR was measured with the unit in closed position across each pole before and after CCT. The results of the test of the contactor in “as-is” condition are shown in [Figure 1.3](#), which show that CR (top chart) and TR (bottom chart) on corroded contacts have extremely high values, which resulted in thermal failure of the unit.

1.3.2.2 Electrical Properties of the Contactor Reconditioned with EN Plating

After completion of the corroded unit testing, the same apparatus was refurbished with EN plating. Out of two previously tested EN platings, the one that showed

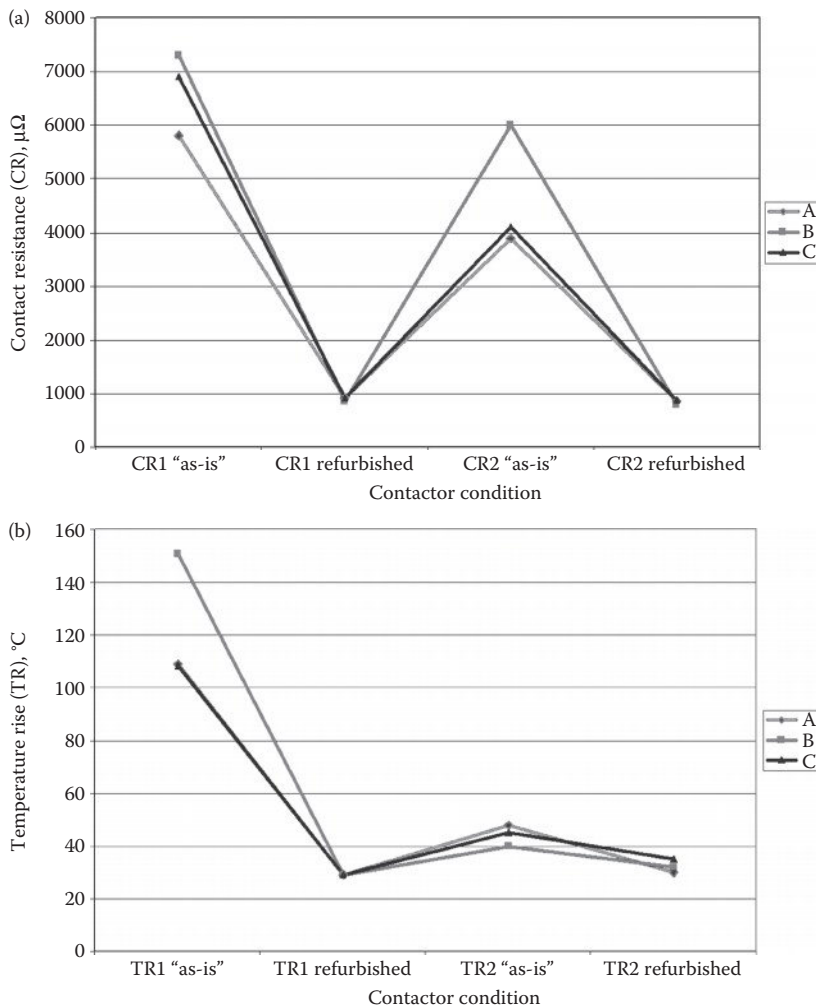


FIGURE 1.3 Electrical CR on three phases of corroded ("as-is") and refurbished contactor (CR1 measured between primary disconnect fingers and CR2 measured by passing them) (a); TR on disconnect fingers on three phases of corroded ("as-is") and refurbished contactor (TR1 measured on load primary disconnect fingers TR2 measured on line primary disconnect fingers) (b). (Modified from Chudnovsky, B.H., Degradation of power contacts in industrial atmosphere: Plating alternatives for silver and tin, *Proceedings of the 49th IEEE Holm Conference on Electrical Contacts*, pp. 98–106, 2003. © 2003, IEEE.)

the best anticorrosion properties has been chosen for plating. The contacts of the MV contactor refurbished with EN-type plating are shown in Figure 1.4. All required electrical tests have been performed to determine and compare the electrical properties of the apparatus before and after reconditioning with selected EN plating.

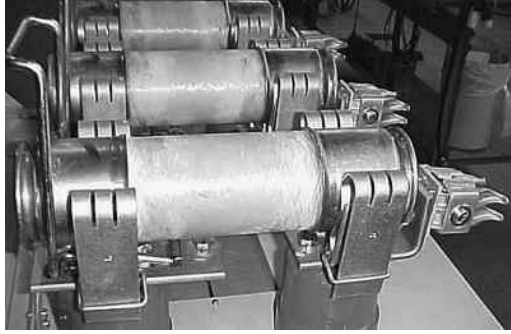


FIGURE 1.4 MV contactor reconditioned with EN plating.

CR is compared in Figure 1.3a for the unit in “as-is” conditions and after refurbishment with EN plating. CR in CR1 was measured between primary disconnect fingers, and CR2 was measured bypassing them. TR values are compared also for corroded unit and for the contactor refurbished with EN plating in Figure 1.3b. Temperature rise (difference between measured T and ambient T) was measured on load primary disconnect fingers (CCT1) and on line primary disconnect fingers (CCT2).

CCT was conducted according to standard requirements with applied rated current 400 A, with a maximum temperature rise (ΔT) of 65°C above the ambient temperature. The test of the “as-is” unit was prematurely interrupted because of extreme overheating of heavily corroded connections. The CR test showed that the resistance of the current-carrying path refurbished with EN plating is higher than the resistance of the same path plated with silver ($\sim 100 \mu\Omega$). However, based on the results of TR measurements, according to CCT, it was concluded that this specific apparatus with EN plating may be used at the same rating as originally designed by OEM.

After the series of life tests were successfully completed, the refurbished unit was installed in the control room of the WWTP facility to determine the rate of plating deterioration at full load in a heavily corrosive environment. The result of the field testing of EN-plated contactors is remarkable; after 20 months of service no visible signs of corrosion could be detected (Figure 1.5).

This is an example of the EN plating use for electrical application, demonstrating that EN plating of carefully chosen composition may withstand a corrosive, hot and humid atmosphere much better than traditional silver and tin plating, which have been practically destroyed in the H_2S atmosphere of a waste water treatment plant.

The EN finish used in the presented example provided not only the best anticorrosion properties, but also relatively low and stable electrical resistance and high hardness as plated. The combination of these properties makes this plating a good alternative for traditional tin and silver plating for electrical connectors of CBs working in a corrosive atmosphere.

1.3.2.3 Precaution in Electrical Applications of EN Plating

In general, EN is not universally superior to silver or tin. EN plating has a higher electrical resistance than traditional plating. The test results presented in this

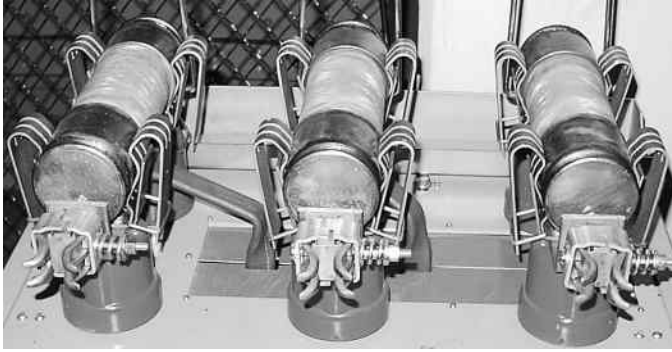


FIGURE 1.5 No signs of corrosion are seen on electrical apparatus with corrosion protective plating after 20 months in service at WWTP.

chapter show that EN plating could be used in specific electrical installations without de-rating the equipment. However, these results cannot be applied blindly to any other type of electrical equipment. Prior to refurbishing a unit or installation, a series of life tests, like the ones described in the example, should be run to demonstrate that the EN-plated equipment could be applied at the same rating as originally designed by OEM.

Considering the higher electrical resistance of EN plating, the heat dissipation and evacuation capabilities of every unit and installation also must be evaluated to determine whether the plating still can be applied at the OEM's original rating. However, in most applications electrical equipment is rarely used at full-rated current. If a unit suffers extremely extensive corrosion, which causes multiple equipment failures, it may be de-rated according to the results of a CCT, to protect the entire installation from corrosion-related thermal accidents.

1.4 ZINC ELECTROPLATING AND GALVANIZATION

Zinc is more corrosion resistant than steel in most natural atmospheres, the exceptions being ventilated indoor atmospheres, where the corrosion of both steel and zinc is extremely low, and certain highly corrosive industrial atmospheres. Coatings of metallic zinc are generally regarded as the most economical means of protecting against corrosion. Seven methods of applying a zinc coating to iron and steel are in general use: hot dip galvanizing, continuous-line galvanizing, electro-galvanizing, zinc plating, mechanical plating, zinc spraying, and painting with zinc-bearing paints.

1.4.1 ZINC ELECTROPLATING

Zinc plating is a common sacrificial coating used in finishing steel parts to provide protection of iron (steel) from corrosion (red rust (RR)). Zinc is usually applied electrolytically to a typical thickness of 5–7.5 μm (0.0002"–0.0003").

The zinc plating protects the underlying steel by the formation of a “galvanic cell,” which results in the zinc corroding preferentially to the steel. RR will not start forming until all zinc has been converted into white rust (WR) (zinc oxide). Normally, zinc plating is used for indoor applications, but can also be used as a base for painting [34].

By itself, zinc plating with a thickness of 5–7.5 μm will probably get not more than 12 h of SS protection per ASTM-B117. With a clear chromate topcoat this is increased to 24–36 h, while a yellow chromate top coating can achieve protection up to ~96 h. Even though it is mostly used as a functional coating, zinc plating does have some decorative appeal. Other properties of zinc plating include: moderate appearance, excellent abrasion resistance, and excellent paint adhesion.

Yellow zinc plating is applied as above, with added yellow dichromate passivate, which greatly improves corrosion resistance. Yellow zinc plating provides salt spray protection (ASTM-B117) for ~96 h.

Black zinc plating is applied as above with black silver nitrate passivate, giving a matte black appearance and a similar corrosion resistance as yellow zinc plating.

1.4.2 ZINC GALVANIZATION PROCESSES

There is usually at least one process that is applicable to any specific purpose. Because these processes are complementary, there are rarely more than two processes to be seriously considered as the best choice for a particular application [35].

1.4.2.1 Hot-Dip Galvanizing

In hot-dip galvanizing, the steel or iron to be zinc coated is usually completely immersed in a bath of molten zinc. This is by far the most widely used of the zinc-coating processes and has been practiced commercially for almost two centuries. The modern hot-dip galvanizing process is conducted in carefully controlled plants by applying the results of scientific research, and is far removed from that conducted years ago, although it is still dependent on the same basic principles.

1.4.2.2 Continuous Galvanizing

This process, known as the *Senzimir process*, uses a small amount of aluminum in the zinc bath and produces a coating with essentially no iron–zinc alloy and with sufficient ductility to permit deep drawing and folding without damage to the coating.

1.4.2.3 Electrogalvanizing

The additional development of continual electrogalvanizing lines added another dimension to zinc-coated steel. In this process, very thin, formable coatings of zinc, ideally suited for deep drawing or painting, are electrodeposited on a variety of milled products by the steel industry: sheet, wire, and in some cases, pipe. Electrogalvanizing at the mill produces a thin, uniform coat of pure zinc with excellent adherence. Electrogalvanized steel is produced by electrodepositing an adhering zinc film on the surface of sheet steel or wire. These coatings are not as thick as those produced by hot-dip galvanizing and are mainly used as a base for paint.

1.4.2.4 The Process of Galvanizing

Before the iron or steel pans are dipped in the molten zinc, it is necessary to remove all scale and rust. This is usually done by pickling in an inhibited acid. To remove molding sand and surface graphite from iron castings, shot- or grit-blasting is generally used, usually followed by a brief pickling operation. In the dry galvanizing process, the work is prefluxed by dipping in a flux solution of zinc ammonium chloride and then passed to a low-temperature drying oven. It is then ready for dipping into the molten zinc bath, the surface of which is kept relatively clear of flux. In contrast, in wet galvanizing, the pickled articles are dipped into the molten zinc bath through a substantial flux blanket.

1.4.3 CONVERSION Zn PLATING: PASSIVATION WITH CrIII OR CrVI

Conversion Zn plating which includes dichromate is a sealer that is deposited on zinc plating. It is very thin and in itself does not provide much corrosion resistance. However, when it is deposited onto a metal, such as zinc plating, it enhances the corrosion resistance and is an excellent base for paint that can be applied over the plating. CrVI (hex chrome) passivation is currently prohibited in compliance with the RoHS directives and replaced with CrIII (tri chrome) passivation. Some of the major differences between the two chromium conversions are in corrosion resistance, color variability, self-healing, and identification.

1.4.3.1 Corrosion Resistance

Under SS tests, corrosion resistance achieved by hexavalent chromes is $120 + h$. Under similar levels of SS tests, trivalent chromate provides ~ 36 h of protection. A topcoat can be added to increase corrosion resistance. The amount of topcoat coverage directly affects the corrosion resistance of the product, and currently no industry standards exist that mandate topcoat thickness. This means the topcoat could vary, and so will the corrosion resistance. The topcoat also creates other barriers, such as increased cost and the inability to paint.

The Standard ISO 4042-E25-009, “Fasteners—Electroplated Coatings,” provides requirements in the climatic test, which is a corrosion test in neutral salt spray (NSS) described in ISO 9227. Conditions of the test correspond to the required classes of the environment. So for indoor service conditions, white rust (WR) withstand should last from 48 to 72 h, and red rust (RR) withstand from 72 to 120 h. WR indicates a corrosion of the zinc coating (object of the CrIII passivation) and RR indicates the corrosion of the substrate (object of the Zn layer). (More about zinc corrosion is given in Chapter 3.) Any other requirement regarding resistances to RR and WR is the subject of another technological solution aiming at increasing the resistance to corrosion (Zn-alloyed nickel, Zn lamellar coating, the addition of a film forming—an additional layer of finishing: mineral (top coat), organic or organometallic). These solutions will have to be determined by the specifications. To use zinc plating in outdoor applications, the RR withstand for zinc-plated stainless steel should be 600 h.

1.4.3.2 Color Variability

In many cases, customers tend to purchase the yellow or gold version of zinc dichromate. This color change is created during the hexavalent chromate conversion process,

which also greatly improves corrosion resistance. With the move to trivalent chrome, the conversion process will no longer generate a color change, and color must be added by using a dye. The use of a dye makes it difficult to maintain a uniform color, and UV exposure can eventually cause the color to fade. The corrosion properties are also sacrificed, as the die has no corrosion resistance properties. The product becomes nothing more than a clear zinc finish that has been dyed yellow.

1.4.3.3 Self-Healing Properties

Trivalent chromate alone has no self-healing properties. This can be improved with the addition of a topcoat, but still only provides about 33% of the self-healing protection of the hexavalent chromium. The topcoat also creates other barriers, such as increased cost and the inability to paint.

1.4.3.4 Identification

There is no easy way to verify whether the products supplied are trivalent or hexavalent. Both are considered a yellow zinc finish; they are similar in color and it is difficult to distinguish the two. The only true way to determine the finish is through chemical testing. The absence of Cr VI must be checked by the diphenylcarbazide test (DPC) called the “drop test.”

1.4.3.5 The Cost Issue

Tri chrome by itself is not much more expensive than hex chrome (chemicals are more expensive, disposal is cheaper), although the difference emerges when corrosion resistance is considered, since tri chrome is markedly inferior in corrosion resistance. Thus, to achieve improvement in the corrosion resistance of tri chrome with some kind of more exotic conversion coating would inherently cost more, would usually involve extra steps and more labor, and would probably have a higher reject rate (also driving up costs).

All these differences should be taken into consideration when performing and using the parts/fasteners with conversion zinc plating.

1.5 METAL WHISKERS ON PLATING (NONCORROSIVE PHENOMENON)

1.5.1 WHISKER PHENOMENON AND CHARACTERISTICS

Metal whiskers are the filaments that grow on various metals and cause electrical short circuits and electronic component damage. There are at least two different phenomena identified for different growth conditions. One type of whisker that grows in any environment, including a vacuum, is found on galvanized or electroplated surfaces of tin, zinc, silver, gold, cadmium, indium, aluminum, lead, indium, antimony, and so on. First described in 1946, highly conductive whiskers can reach several millimeters in length with a typical diameter between 1 and 5 μm and growth rates around 0.1 $\text{\AA}/\text{s}$ under ambient conditions.

The precise mechanism for such growth remains unknown, but theories suggest that whisker formation is encouraged by compressive mechanical stresses

developed during the electroplating process. The corrosion-related phenomenon of gigantic whiskers growing on silver is described in Section 3.5. Such whiskers are found only on silver plating, alloys and pure metal, which have been exposed to an industrial atmosphere rich in hydrogen sulfide. There is no explanation of this phenomenon.

In this section a historical review of risks and failure mechanisms and the development of various mitigation techniques associated with metal whiskers is presented.

The tendency of pure tin plating to form tin whiskers has been known for many years. Tin whiskers have been found to form on a wide variety of tin-plated component types under a range of environmental conditions. These whiskers are composed of nearly pure tin and are therefore electrically conductive and can cause shorting of electronics. The growth of whiskers has caused reliability problems for electronic systems that employ components plated with tin [36–39].

Other metal galvanized or electroplated deposits are also prone to growing whiskers. Metal whiskers are completely different from the more commonly known dendrites, not only by their shape and orientation, but also by the mechanism that forms them. Dendrites form in damp environments when metal ions dissolve and are then redistributed in the presence of an electromagnetic field, due to a phenomenon called electromigration.

As to metal whiskers, there is not a single theory that can explain their growth. What causes tin whiskers to grow is still under debate, although it is generally accepted that stresses involved in plating play a major role [40].

1.5.1.1 Conditions and Characteristics of Growth

Most metal whiskers grow in any environment including a vacuum, and do not require dissolution of the metal, the presence of electromagnetic field, or a specific range of ambient temperature. Whiskers are found on galvanized or electroplated surfaces of tin, zinc, silver, gold, lead cadmium, and other metals. These electrically conductive growths can reach several millimeters in length; infrequently, whiskers as long as 10 mm have been reported. Most studies are focused on tin whiskers since most electronic components use tin plating (Figures 1.6 and 1.7).

Extensive accounts of dozens of studies may be found in Refs. [39,41], which study various mechanisms for whisker growth and the effects of multiple process parameters. The effects of plating process parameters such as current density, temperature, substrate preparation, substrate materials, and bath components have been studied. The influence of plating thickness, underplating, postplating annealing, plating structure, and alloying agents on whisker growth has been evaluated.

None of the theories proposed for the explanation of the phenomenon can be considered as proven, although some of them have allowed the development of methods for growth prevention. One of these theories is that whiskers form in response to the compressive stresses that develop during the electroplating process; another theory suggests that mechanical stresses produce an environment favorable for whisker formation. Nonetheless, the precise mechanism for metal whisker formation remains unknown.

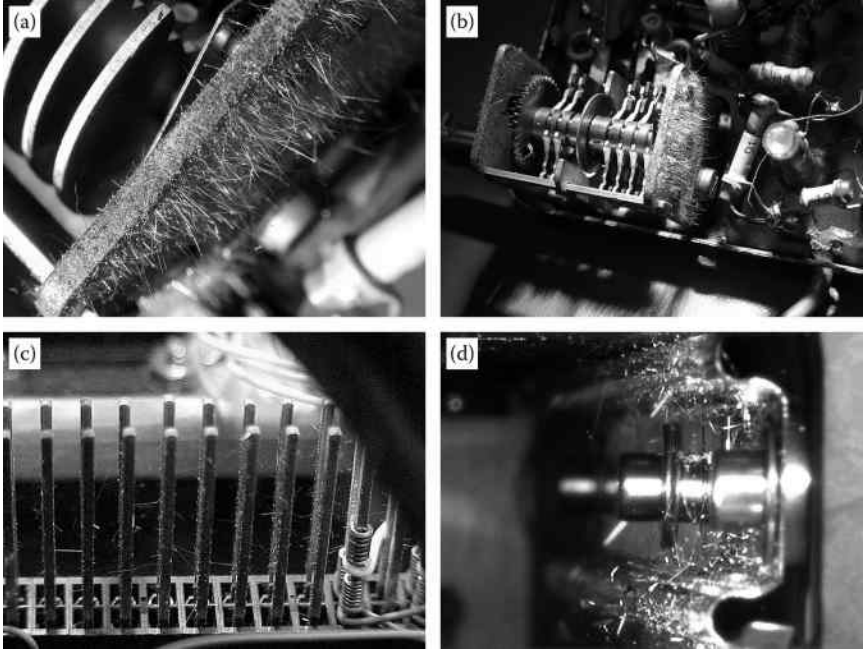


FIGURE 1.6 (See color insert.) Tin whiskers. (a) On tin-plated housing on variable air capacitor built in 1959, found in 2006; (b) on a 1960s era variable air capacitor; (c) on connector pins; and (d) on printed circuit card guides from Space Shuttle. (Courtesy of the NEPP Program, nepp.nasa.gov/whisker/)

There is much debate in the industry regarding which tin plating processes are prone to whisker formation. Most of the literature agrees that “pure tin” electroplated surfaces (especially those that employ brighteners in the plating process) are the most susceptible to whisker formation. There are also reports that tin–lead plating can also grow whiskers; however, such whiskers are generally reported to be $<50\text{ }\mu\text{m}$ long.

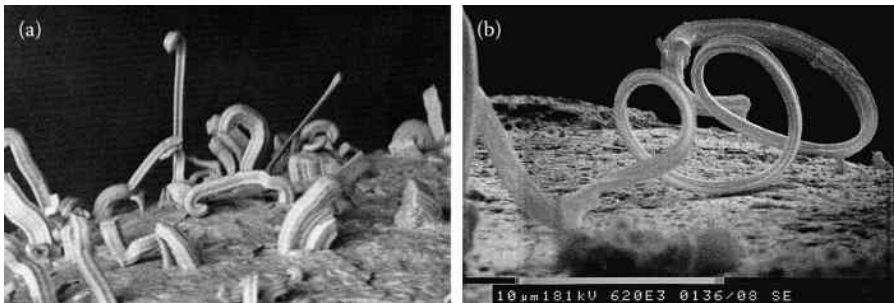


FIGURE 1.7 SEM pictures of tin whiskers: (a) straight and hooked tin whiskers; (b) spiral shaped tin whiskers. (Courtesy of the NEPP Program, nepp.nasa.gov/whisker/)

Some of the observed characteristics of tin whiskers [42] are

1. *Shape*: Whiskers may be straight, kinked, hooked, or forked with outer surfaces often grooved. Some growths may form as nodules or pyramidal structures.
2. *Incubation period*: The incubation time before whiskers form is very unpredictable and can range from days to years. Under high stress conditions, whiskers have been found to grown very rapidly.
3. *Growth rate*: Growth rates from 0.03 to 9 mm/year have been reported. Growth is highly variable and is likely to be determined by a complex range of factors including plating chemistry, plating thickness, substrate materials, grain structure, and environmental storage conditions.
4. *Whisker size*: Whiskers as long as a few millimeters are most common, with some whiskers as long as 10 mm in length (Figure 1.7). Typical diameters are a few microns, while some are found to be as large as 10 μm .

1.5.1.2 Environmental Factors

There is contradictory information regarding the influence of various environmental factors on whisker formation, and the ability of these factors to accelerate or retard the growth.

Environmental factors that need to be considered are

- *Temperature*: Some reports state that $\sim 50^\circ\text{C}$ ambient temperature is optimal for whisker formation, while others observe that at room temperature whiskers grow faster. Whisker growth usually ceases at temperatures above 150°C .
- *Pressure*: Whiskers will grow in a vacuum as well as at atmospheric pressure.
- *Moisture*: Some observations show that whiskers grow more readily in high humidity, while others do not find moisture to be a contributing factor.
- *Electric field*: Whiskers grow spontaneously without requiring an applied electric field. However, it was found that whiskers can bend due to electrostatic forces, thus increasing the possibility of tin whisker shorts.

1.5.1.3 Historical Account of Metal Whisker Hazards

Metal whiskers, highly conductive filaments reaching several millimeters in length, can cause electrical short circuits or electronic component damage. The specific causes of failure are particularly difficult to define because whiskers may vaporize or disintegrate, leaving no trace behind.

The most serious hazard posed by metal whiskers is a metal vapor arc, in which the whisker vaporizes into a cluster of extremely conductive metal ions capable of carrying hundreds of amperes of current. Metal whiskers can also cause voltage to jump across electrical circuitry and cause short circuits. The history of these failures began during WWII, when cadmium whiskers were found in electrical equipment.

When tin and zinc began to be used instead of cadmium later in the 1940s, Bell Labs reported shorting caused by the whiskers. When investigating failures on channel filters in telephone transmission lines, Western Electric and Bell Laboratories first documented the existence of metal whiskers in the 1950s and 1960s [36,37]. Bell Labs investigated whether the addition of some element to tin coating would prevent whiskering. After it was found that adding lead prevented the growth, they discontinued research on the metal whisker phenomenon.

Since then, hundreds of scientific and technical papers have been published and reviewed. The best and the largest collection of papers and images on whiskers are posted on the NASA website, the page nepp.nasa.gov/WHISKER/. A complete account and review of these studies is given in Refs. [36–40]. The most comprehensive account of documented failures caused by metal whiskers is given in Refs. [36,37]; see Table 1.12.

TABLE 1.12
Metal Whiskers Failures: 2000s

Year	Application	Industry	Failure Cause	Whiskers On?
2000	Galaxy VII (Side 2)	Space (complete loss)	Tin whiskers	Relays
2000	Missile program “D”	Military	Tin whiskers	Terminals
2000	Power Mngm Modules	Industrial	Tin whiskers	Connectors
2000	Solidaridad I (Side 2)	Space (complete loss)	Tin whiskers	Relays
2001	Galaxy MR (Side 1)	Space	Tin whiskers	Relays
2001	Hi-Rel	Hi-Rel	Tin whiskers	Ceramic chip caps
2001	Nuclear power plant	Power	Tin whiskers	Relays
2001	Space ground test equipment	Ground support	Zinc whiskers	Bus rails
2002	DirecTV 3 (Side 1)	Space	Tin whiskers	Relays
2002	Electric power plant	Power	Tin whiskers	Microcircuit leads
2002	GPS receiver	Aeronautical	Tin whiskers	RF enclosure
2002	MIL aerospace	MIL aerospace	Tin whiskers	Mounting hardware (nuts)
2002	Military aircraft	Military	Tin whiskers	Relays
2002	Nuclear power plant	Power	Tin whiskers	Potentiometer
2003	Commercial electronics	Telecom	Tin whiskers	RF enclosure
2003	Missile erogram “E”	Military	Tin whiskers	Connectors
2003	Missile erogram “F”	Military	Tin whiskers	Relays
2003	Telecom equipment	Telecom	Tin whiskers	Circuit breaker
2004	Military	Military	Tin whiskers	Waveguide
2005	Communications	Radio (1960s vintage)	Tin whiskers	Transistor TO package
2005	Millstone nuclear power plant	Power	Tin whiskers	Diode (axial leads)
2005	Optus B1	Space	Tin whiskers	Relays
2005	Telecom equipment	Telecom	Tin whiskers	RF enclosure
2006	Galaxy MR (Side 2)	Space	Tin whiskers	Relays

Source: Courtesy of the NASA Electronic Parts and Packaging (NEPP) Program, nepp.nasa.gov/whisker/.

1.5.2 TIN WHISKER MITIGATION TECHNIQUES

Development of mitigation techniques [43] that could greatly enhance resistance to whisker formation for tin-based films is very important, since tin whiskers are the most dangerous growth for electric and electronic devices. However, none of these techniques necessarily prevents the whiskers' ultimate formation.

Since compressive stresses are thought to be fundamental to whisker formation, mitigation approaches should somehow alter the stress state within the tin. Underplating, alloying, plating chemistry, and heat treatment all have an effect on the stress state of the tin and encompass a variety of commercially available mitigation methods. The choice of the method also depends on the application.

1.5.2.1 Underplating

Underplating may be effective by forming a barrier at the tin–substrate interface. Therefore, adding a nickel (Ni) layer between tin plating and a copper (Cu) base metal may mitigate whisker formation by forming a barrier to the diffusion of Cu into the Sn. The thickness, porosity, and ductility of the nickel plating are very important to ensure an effective barrier layer for the copper that will not crack during lead formation. A minimum porosity-free layer thickness of 0.5 μm has been shown to mitigate the growth of Sn whiskers for devices subjected to Pb-free reflow assembly conditions [44].

It has also been shown that Ni of this thickness is not fully converted and consumed to intermetallic compounds (IMC) after $3 \times 260^\circ\text{C}$ reflows, and that the nickel layer is sufficiently ductile and will not crack during a subsequent lead forming operation [45]. On the other hand, Ni underplating may not be beneficial in conditions where the compressive stress-inducing mechanisms originate at the tin surface or within the tin matrix itself. Ni does not prevent the corrosion and oxidation of Sn in a high-humidity environment.

Adding silver (Ag) underplating between tin plating and copper (Cu) base metal has been proposed as a method of mitigating whisker formation, similar to Ni as noted above [46]. Components using silver underplating should have a minimum silver thickness of 2 μm . However, there is limited whisker test data supporting the effectiveness of the Ag underplating in whisker mitigation.

1.5.2.2 Addition of Lead

Tin plating with >3% lead (Pb) has been the industry-accepted finish for over 50 years and has been shown to mitigate Sn whisker formation [47]. It has become the standard used when comparing and evaluating Sn whisker mitigation practices. Since the 1990s, most U.S. MIL specs require adding Pb to any tin coatings used around electronics, with the concentration usually as 2–3% Pb by weight. However, adding lead to tin plating became no longer an option for most products after July 1, 2006.

In response to campaigning from environmental groups to stop the use of lead, two regulations—the Waste Electrical and Electronic Equipment (WEEE) and RoHS of the European Parliament and the European Union Council—have compelled European and U.S. electronics manufacturers to produce lead-free components and protective coatings, which have a high potential for whiskers formation [48].

This has, in turn, resulted in the increased incidence of electrical failures, although the use of Pb is not 100% guarantee against the formation of whiskers. A further discussion on the influence of RoHS and WEEE initiatives on dealing with tin whiskers is presented in Section 1.5.3.

1.5.2.3 Heat Treatments

Heat treatments may be subcategorized as annealing, fusing, and reflow. Annealing is a heating and cooling process typically intended to soften metals and to make them less brittle. Fusing and reflow are similar in that both melt and resolidify tin plating under relatively slow cooling conditions.

1.5.2.4 Hot-Dip Tin Plating

Hot-dip tin is a molten tin bath process that is intended for electronic components. It has primarily been used for structural steel parts, connectors and devices, such as relays, but not for lead frame components. Hot dipping with SnAg₄ or SnAgCu, is generally an effective mitigation practice and considered to be whisker free. However, there is evidence that when pure tin is used this process may not be effective [49].

1.5.2.5 Thicker Tin Finish

Industry data indicate that thicker tin finishes show a lower propensity for tin whiskers and/or a greater incubation time before tin whiskers occur. It is recommended that the tin thickness for components without a nickel or silver underplating be a minimum of 7 μm with 10 μm nominal [50,51]. When nickel or silver underplating is used, the minimum tin thickness should be of appropriate thickness to ensure component solderability over the intended shelf life and to prevent complete consumption of Ni in the intermetallic Ni/Sn phase.

1.5.2.6 Conformal Coating

The use of conformal coatings (materials applied in thin layers, often by dipping, spraying or flow coating) on a circuit board assembly has been shown to reduce the electrical shorting risks from whiskers [6,52]. Thicker coatings ($\geq 100 \mu\text{m}$ or 3.9 mil) have been shown to prevent or delay whisker penetration, while thinner coatings act as a dielectric layer for whiskers that may break off in an assembly.

Conformal coating could be used in conjunction with other mitigation methods previously discussed. Conformal coating also reduces the corrosion of Sn. There is an opportunity for more study in this area and the mitigation results will vary with the specifics of the assembly and its sensitivity to whisker problems.

When applied on top of a whisker-prone surface, conformal coat can sometimes keep whiskers from pushing through. When applied to a distant conductor, conformal coat can block whiskers from electrically shunting distant conductors. It also provides an insulating barrier against loose conductive debris.

1.5.2.7 Non-Tin Plating and Coating

Non-tin platings, such as nickel/palladium/gold, nickel/gold, or nickel/palladium, do not have Sn whisker problems and should be considered for lead-frame applications. This plating has a more than 10-year history of field use, 1992 to the present [53].

Non-tin plating, however, does have other potential issues, including adhesion to mold compounds that need to be evaluated prior to product conversion. Printed circuit boards (PCBs) that were previously hot air solder leveled (HASL) SnPb will be finished with either electroless nickel immersion gold (ENIG) (EN immersion gold) or HASL (tin/silver/copper Alloy) as the application demands. Organic Solderability Preservative (OSP) may be used if the application permits [54].

1.5.3 TIN WHISKERS AND THE ROHS INITIATIVE

1.5.3.1 Lead-Free Solders

The RoHS and WEEE legislations set a deadline of June 2006 to achieve the goal of Pb-free solder. It was found that Pb-free solder is, to some extent, more brittle than the traditional solder. Substitute solders that have been developed may be applied too thinly or with too little heat, which results in stressing of the circuit board laminate (a contributing factor in whisker growth). An example would be a recalled product from the Swiss watch-making company Swatch, which reportedly cost \$1 billion. The company was later granted a permanent exemption from the RoHS directive for its exports within the European Union, and was allowed to put Pb back in the solder.

Many experts doubt that a reliable lead-free process will be implemented soon, and debate among professionals continues. However, companies such as IBM and National Instruments say that they are now achieving RoHS-compliant techniques even for exempt products. So far, the last source to count on for information is the manufacturers [55]. Currently, the United States has not made Pb-free solder mandatory, but does offer tax benefits for reducing or eliminating its use [56].

1.5.3.2 “Pure” Tin Finishes

Some types of electronics were exempted from the law since its inception. Among these exceptions were military and other national security equipment and certain medical devices. There is no pending U.S. legislation mandating lead-free electronic products, and should such legislation arise, military, aerospace, and medical equipment manufacturers would likely be exempt.

Nevertheless, the Department of Defense (DoD) and NASA believe that the use, and therefore the risk, of pure tin finish (tin which contains <3% Pb by weight shall be considered “pure” for this purpose) on electronic components will increase because: (1) the commercial industry has stated initiatives to eliminate lead (Pb) from electronics; (2) defense and aerospace industry trends show increasing usage of commercial components; and (3) continuing reductions in circuit geometry and power may result in even small whiskers causing catastrophic failures.

However, integrators and designers of high-reliability systems exert little or no control over component-level plating processes that affect the propensity for tin whiskering. Challenges in how to ensure long-term reliability, while continuing to use COTS (commercial off-the-shelf) parts plated with pure tin, continue to arise [57,58,59]. The National Electronics Manufacturing Centre for Excellence, sponsored by the U.S. Navy, did find that modifying the temperatures at which soldered items are bathed and stored diminished whiskering, but nevertheless recommends the “use of lead in conflict with future industrial practice” [55].

1.5.4 WHISKER MITIGATION LEVELS CLASSIFICATION

Currently there is still no commonly used industry standard for pure tin finishes on applications. Most individual companies are developing their own standard of acceptability of tin and zinc finishes used on parts. Some companies have responded to current industry pressure by completely changing to pure tin and zinc finishes, although they have not yet incorporated new part numbers to reflect this change in material. This practice only leads to confusion in the procurement process. Parts should be inspected on arrival, but this costs a lot of time and money.

In response to this situation, a system of whisker mitigation level classification standards was proposed in Ref. [57] to match potential risk with appropriate mitigation for tin and zinc whisker issues. It was suggested to define the whisker mitigation level for each hardware system or subsystem. Five proposed whisker mitigation levels (I, II, III, IV, and V) determined the type of control and the recommendation of system types for each level.

In 2006, the ANSI/ITAA published GEIA-STD-0005-2, “Standard for Mitigating the Effects of Tin Whiskers in Aerospace and High Performance Electronic Systems,” which established processes for documenting the mitigating steps taken to reduce the harmful effects of tin finishes in electronic products. In this Standard the nomenclature of the five levels has been changed from I, II, III, IV, and V to 1, 2A, 2B, 2C, and 3.

The Standard describes processes for mitigating the detrimental effects of tin whiskers in electronic systems used in military, aerospace, and other high-reliability applications. The Standard is intended for use to document processes and to ensure performance, reliability, airworthiness, safety, and certifiability of electronic systems in which harmful forms of tin may be introduced into the production or maintenance process.

The highest level of control is provided by Level 3 (or V in Ref. [57]), where no pure tin or zinc finishes are permitted to be used. Typical systems where Level 3 would be appropriate include space-based systems, strategic missile vehicles, and implanted medical devices. But application-specific risk assessments for the use of tin would, of course, typically not be a part of a standard process for Whisker Control Level 3, because the use of tin is totally banned.

A high level of control is provided by Level 2C (IV), according to which pure tin and zinc finishes are allowed only very limited uses. Special exemptions may be granted at this level of control to permit pure tin or zinc use on a case-by-case basis. Typical end uses where Level 2C would be appropriate include tactical missiles, safety-critical avionics, and so on.

Level 2B (III) provides a moderate level of control. Pure tin and zinc finishes are only permitted when the risk of failure can be reasonably determined to be minimal. Level 2B would apply to a wide range of high-reliability systems. Such systems would typically permit repair and replacement of failed assemblies as a normal part of their logistic plan. Typical systems include surface-based military radar and communications systems, and critical commercial applications.

Application-specific risk assessment will generally be applicable to Whisker Control Levels 2B and 2C. Under Whisker Control Level 2C each and every incidence

of tin usage must be analyzed, justified, and documented. A standard risk assessment algorithm offers one method of performing these analyses in a well-defined and easily documented manner.

Under Whisker Control Level 2B, tin may be used under a set of predefined conditions, or blanket exemptions. These conditions must be defined and justified. A standard risk assessment algorithm again can provide a well-defined and documentable method for justifying exemptions. Here, the use of tin may also be justified on a case-by-case base exactly as with Level 2C.

Level 2A (II) provides for a minimal level of control where pure tin and zinc finishes are restricted from use only in specific applications. Unless otherwise indicated, pure tin and zinc are considered acceptable for use. Typical systems where this level could properly apply include military test equipment, industrial electronics, and transportation. Level I classification provides for no special controls for pure tin or zinc finishes. All components may be used without regard to issues of tin or zinc whiskering. This is essentially the “best commercial practices,” or COTS approach.

Typical systems where Level 1 (I) would be appropriate for use include consumer electronics and nondeliverable prototypes. The use of pure tin is currently prohibited by the military and NASA. The summary of procurement specifications can be found in Ref. [60].

Whisker Control Levels 1 and 2A do not generally restrict the use of tin in any particular application. Therefore, application-specific risk assessments would typically not be performed as part of the standard process.

The Standard establishes a framework within which manufacturers and their customers can establish guidelines for the control of tin usage. One popular method for determining the suitability of pure tin in a given application is the use of a standard tin whisker risk assessment algorithm; the last revision (D) was accepted in January 2011 [61]. The use of an algorithm facilitates standardization of tin risk decision-making across and between organizations.

Based on mitigation techniques suggested by industrial recommendation and standards, International Electronics Manufacturing Initiative (iNEMI) (International Electronics Manufacturing Initiative) proposed the recommendations for bus bar plating [62] which may be free of metal whiskers ([Table 1.13](#)).

When applying tin (Sn) on bus bars as a finish, tin whiskers are a concern, particularly when bus bar connections result in mechanical stresses on the finish. This finish has been used on bus bars in many products for years, so the application may still be acceptable even with tin whiskers. Success highly depends on application and it is up to the user to make the final decision as to acceptance of this finish. iNEMI Tin Whisker User Group concludes [62] that if Sn finishes are used, a tin whisker mitigation practice is recommended.

When chromium finishes are applied, the plating should not contain CrVI (Hexavalent Chrome).

1.5.5 WHISKERS ON OTHER METAL PLATINGS

Whiskers have been found on many other plating materials other than tin: zinc, lead, aluminum, cadmium, gold, and so on ([Figure 1.8](#)).

TABLE 1.13
Recommendations for Bus Bars Plating

Plating	On Copper Alloys	On Aluminum
None (unfinished)	OK	OK
Nickel	OK	OK over copper strike plating
Silver (immersion or electroplate)	OK	OK over copper strike plating
Chromium	OK	OK over copper strike plating
Matte Sn	Not recommended	Not recommended

Source: From Smetana J. iNEMI recommendations on lead-free finishes for components used in high-reliability products, *iNEMI Tin Whisker User Group IPC/APEX*, February 2006. http://thor.inemi.org/webdownload/projects/ese/tin_whiskers/User_Group_mitigation_May05-REMOVED_5-12-05.pdf. With permission.

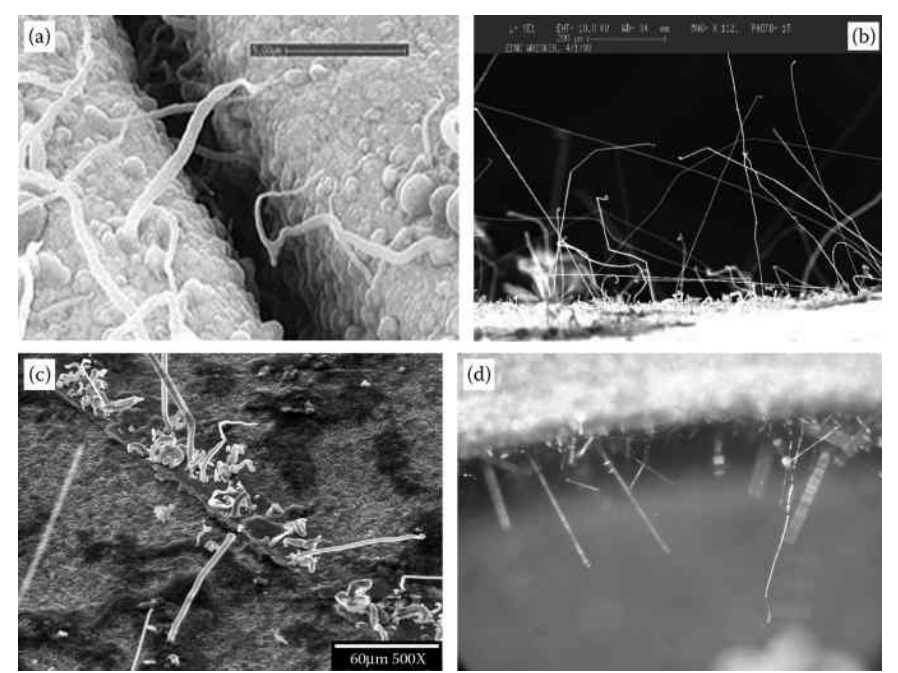


FIGURE 1.8 SEM pictures of whiskers on gold (a), zinc (b,c), and cadmium (d). (Courtesy of the NEPP Program nepp.nasa.gov/whisker/)

Zn whiskers have been well studied [27] and have, in general, the same physical characteristics as tin whiskers:

- *Length:* a few millimeters or less
- *Diameter:* a few microns (thousandths of a millimeter)
- *Shapes:* straight or kinked filaments, nodules

- *Texture:* fluted and/or striated along axis of growth
- *Conductive:* can carry tens of milliamperes before melting.

The mechanism of Zn whiskers growth is unconfirmed, as is the case for tin whiskers. However, the most plausible mechanism for tin whiskers is that they grow to relieve compressive stress within the film, and this may also be the case for zinc whiskers. The incubation period ranges from days to years, with growth rate typically <1 mm/year.

The sources of Zn whiskers are the parts with Zn plating, such as mechanical hardware (nuts, screws, and washers) and equipment racks (cabinets, chassis, bus rails, etc.).

Zinc whiskers may grow on electroplated or hot-dip galvanized zinc plating. However, electroplated zinc is far more susceptible to whisker growth [63–65]. Zinc whiskers, which may sometimes grow to be 1–2 mm long, threaten instrument transformers equipment when they become dislodged and airborne, which could happen when the tiles are disturbed during their removal or when pulling or removing under-floor cables. If zinc whiskers are ingested by information technology (IT) hardware equipment (computers, data centers, and so on), a circuit with voltages higher than about 25 V may suffer electrical short circuiting, arcing, signal perturbations, or catastrophic failures [66]. If zinc whiskers are present, remediation involves replacing the contaminated raised-floor tiles and hiring professionals to clean the data center.

1.6 PLATING ON ALUMINUM

1.6.1 USE OF ALUMINUM IN ELECTRICAL INDUSTRY

Most electrical applications of Al use this metal for the bus instead of copper. Physical, mechanical, and chemical properties are compared for copper and aluminum, as well as for three plating materials (nickel, silver, and tin) in Table 1.14 [67]. There are many reasons why aluminum is often chosen as a material for electrical parts. Copper bus material is three times heavier and more expensive than aluminum. The dollars per amp is less for aluminum than it is for copper (current-carrying capacity).

Although there is a definite benefit in cost from using aluminum bus, it is not as conductive as copper. Aluminum has about $1/2$ the conductivity of copper. With more conductivity comes less resistance; therefore, you have less heat generation. So, for applications where more heat could be generated and longer life of the equipment is important, copper bus is more often used.

Usually, the decision as to which material to choose for the bus is taken based on the specific application. The aluminum bus should be plated to protect it from corrosion and ensure long life, because when corrosion or oxidation occurs on aluminum it decreases its conductivity considerably. The choice is usually made between silver and tin.

1.6.1.1 Choice of Plating

In some cases, when aluminum and copper are joined together in bolted electrical connections, it is important to choose the plating both for Cu and Al that will provide

TABLE 1.14**Selected Physical, Mechanical, and Chemical Properties of Base Metals (Al or Cu) and Metals, Used as Plating (Cu, Ni, Ag, Sn)**

Physical Property	Al	Cu	Ni	Ag	Sn
Coating thickness (μm)	—	10–15	3–5	3–5	10–15
Electrical resistivity ($\mu\Omega\text{-cm}$)	2.96	1.72	6.84	1.59	11.0
Thermal conductivity ($\text{W/m}\cdot\text{K}$)	210	380	70	418	64
Microhardness (MPa)	170	500	8000	700	60
Tensile strength (σ_u) (MPa)	172	195	59	55	12
Coefficient of thermal expansion ($10^{-6}/^\circ\text{C}$)	23.6	16.8	13.3	19.6	23
Temperature coefficient of resistivity ($10^{-3}/^\circ\text{C}$)	4.03	3.97	6.90	4.01	4.70
Melting temperature ($^\circ\text{C}$)	660	1084	1455	1482	232

Source: Modified from Braunovic M. Evaluation of different platings for aluminum-to-copper connections. *IEEE Transactions on Components, Hybrids, and Manufacturing Technology*, 15(2), 216–224, April 1992. © 1992, IEEE.

better electrical properties and stability [67]. Tin plating of copper bus bars has long been used for joining copper to copper. With the increased use of aluminum in the electrical industry and the rising number of aluminum-to-copper interfaces, the use of tin plating on copper became an established practice.

Silver is an excellent choice for plating. As the best conductor, it is less sensitive to deteriorating processes such as fretting, but silver plating is expensive. Therefore, the use of silver is justified only in specific cases and in environments free of sulfurized contaminants.

Nickel is also a very good plating material; it has superior resistance to corrosion and oxidation and does not form IMC with aluminum, but it also has some disadvantages. It does not protect aluminum from galvanic corrosion, and forms subsurface corrosion when plated over aluminum. It is also sensitive to fretting. A study, however, shows [67] that nickel plating enhances the stability of Al-to-Cu connections.

Tin plating provides better joint connections because it is not as hard a material as silver. The harder the plating material the more contact surface area is lost. Silver provides for better conductivity. Each material has its benefits and drawbacks, and is chosen depending on the application. Although both materials are acceptable in most installations, there are some atmospheres where silver plating is not desirable. These conditions exist in wastewater treatment and pulp and paper facilities (see Section 3.3).

1.6.1.2 Difficulties with the Plating of Aluminum

The main difficulty connected with the plating of aluminum is the presence of the oxide film on the surface of Al. An extreme reactivity of bare aluminum results in rapid reformation of the film while exposed to air or to aqueous solutions.

Additionally, the difference in the linear expansion coefficient of the aluminum alloys and most of the metals commonly deposited on Al may cause adhesion

problems. In applications in which considerable temperature changes occur, the differential expansion of aluminum and the metal coating may cause sufficient strain to rupture the bond between the deposit and the basic metal [68].

1.6.2 METALS USED TO PLATE ALUMINUM

For nonelectrical applications, nickel and chromium are the metals most commonly deposited on aluminum; however, electrical applications require the application of other metal deposits. Aluminum is anodic to most of the metals commonly deposited on it, and hence, it is essential that the deposited metal be largely pore free if good protection is to be achieved.

Various metals have been applied to aluminum to provide a solderable surface. These include tin, copper, zinc, silver, and nickel. Tin and sometimes silver deposits are used on aluminum bus bar ends to improve electrical conductivity at the joints. In the past, lead–tin alloy electrodeposits have been applied to bearing surfaces prior to the ban on lead. In electrical devices there have been many cadmium-plated aluminum components such as switch boxes and instrument panels where electrical earthing needed to be protected from corrosion, although nowadays cadmium plating is also banned due to toxicity.

Aluminum wires with an extruded copper coating are being used for electrical installations in place of solid copper wires. Other metallic coatings for aluminum conductor wires are in use. When plating has to be chosen for aluminum for a specific application [68], it is important to consider the various physical properties of different metals available for Al plating (Table 1.15).

1.6.3 METHODS FOR PLATING ON ALUMINUM

Pretreatment processes for plating aluminum are presented in Ref. [68]. Pretreatment processes begin with degreasing, followed by etching, deoxidation, and ion-exchange

TABLE 1.15
Plating for Aluminum with Acceptable Physical Properties

Metal	Thermal	Electrical	Wear	Friction	Anticorrosion	Solderability
Cr			Good		Good	
Ni			Good		Good	
Cu	Good	Good				Good
Ag	Good	Good		Good		
Sn		Good		Good	Good	Good
Zn					Good	
Au		Good			Good	Good

Source: Modified from Moller P. *Plating on Aluminum*. TALAT lecture 5205, Online. Available: <http://www.eaa.net/aaa/education/TALAT/lectures/5205.pdf>.

Zn plating (or tin plating). Whenever tin plating is used in the pretreatment process, it is necessary to provide underplating (usually electrolytical bronze strike).

The plating, then, may be either electroless (e.g., Ni or other metals), or electrolytic plating (Cu or Ni). If needed, additional plating may be applied, such as gold (Au) or silver (Ag). These procedures are described in ASTM Standard B253-87(2010), “Standard Guide for Preparation of Aluminum Alloys for Electroplating” [69].

1.6.3.1 Plating Classifications

Generally, methods for producing deposits on aluminum may be classified as follows:

1. Processes based on the zincate immersion technique
2. Processes based on the stannate immersion technique
3. Direct plating methods
4. Processes based on mechanical preparation
5. Chemical etching procedures
6. Processes based on preparation by anodic or chemical oxidation

To obtain a good surface finish of the plated aluminum, a proper pretreatment and jiggling of the profiles has to be carried out. The usual process steps are as follows (there is at least one rinsing step after each main process step): polishing, jiggling, degreasing/cleaning, etching, zincating (zinc immersion), or double zincating (double zinc immersion). After these steps, electrolytic plating (Cu or Ni) or nickel (electroless) is applied.

Of the preplating techniques, the zincate process is by far the most widely used. The stannate process is recommended for specific applications. The zincate and stannate processes have mainly superseded the other methods for plating on aluminum. Some of these methods are still in use and some continue to be investigated, although with little to no commercial exploitation.

1.6.3.2 Pretreatment by Zincating

To obtain good adhesion when plating on aluminum it is necessary to start with a precoat of zinc or tin. This precoating is the pretreatment needed prior to the main metal plating. Most plating on aluminum is currently carried out on top of chemically deposited zinc produced by immersion in modified zincate solutions. The zincate process has been developed into a relatively simple, cheap, and reliable technique for plating on aluminum and a wide range of aluminum alloys. It is less sensitive to alloy composition than processes based on anodizing pretreatments, does not need the applied power requirements of anodizing, and is cheaper than the stannate immersion process owing to the high price of tin.

The basic reactions in the alkaline zincate solution are the dissolution of aluminum and the deposition of zinc. The zincate solution is normally made up of zinc oxide and caustic soda, and it has been shown that the ratio of these constituents has a profound effect on the adhesion of the subsequent deposit. Physical conditions, as well as time of immersion and temperature, can also affect the degree of adhesion. It was indicated that the presence of nickel in the zincate solution improves

the adhesion of nickel plated directly onto the zinc deposit. Copper also assists the adhesion to some alloys, and the substitution of zinc oxide by zinc sulfate was found to give further improvement.

1.6.3.3 Tin Plating Techniques on Al

Various techniques of plating are used in the electrical industry. Several of them are based on different versions of the same process, called Alstan (Table 1.16), which utilizes proprietary solutions including cyanide-containing chemicals. Alstan plating techniques are supposed to provide tin plating on aluminum with low surface-to-surface contact resistance (CR) and to minimize surface corrosion.

For example, the Alstan 80 process consists of an immersion or electrolytic activation step in the proprietary Alstan 80 solution followed immediately by a bronze alloy strike without an intermediate water rinse. Following this processing sequence and a subsequent appropriate acid dip and water rinse, the work is ready to be plated, as desired. The primary advantage of the Alstan 80 process is an improved corrosion resistance of the plated parts. It is particularly important for using tin on aluminum bus bars, connectors, and so on in electrical equipment exposed to a corrosive environment.

Other activation techniques use noncyanide chemicals, which are considered more environment friendly, such as the plating technique called Bondal, which uses a surface activation procedure with a cyanide-free zincate solution and copper strike prior to tin plating. Either with or without cyanide-containing solutions, these processes prepare the surface of the aluminum bus bar for tin plating through multiple-step procedures including underplating of a thin layer of bronze or copper.

1.6.4 QUALITY OF TIN PLATING ON AL FOR DIFFERENT PLATING TECHNIQUES

The plating process itself, particularly the plating technique, is an important factor that may affect the quality of plating. The age of the bath and the position of the

TABLE 1.16
Alstan Processes for Plating Tin on Aluminum Alloys

Process	Type	Description
Alstan 60	Immersion	Matte tin plating process for aluminum alloy pistons.
Alstan 65	Immersion	Matte tin plating process for aluminum alloy pistons. This process runs with lower tin content.
Alstan 70	Immersion	A process for the preparation of aluminum and its alloys for plating with good adhesion to the base metal.
Alstan 80	Electrolytic	A process for the preparation of aluminum and its alloys for plating with good adhesion to the base metal.
Alstan 88	Electrolytic	A process for the preparation of aluminum and its alloys for plating with good adhesion to the base metal.

Source: Adapted from industrial standards for tin plating on aluminum.

part in the bath may also significantly affect the quality of the plating. To determine whether the influence of these factors is significant [70], copper bus bars were plated using three different techniques of plating tin on aluminum: Alstan 80, Alstan 88, and Bondal.

Each of two Alstan techniques is based on two different versions of the same process with proprietary solutions including cyanide-containing chemicals. Both techniques are supposed to provide tin plating on aluminum with a low surface-to-surface CR and to minimize the surface corrosion; they are often used for plating Al bus bars in the electrical industry. The noncyanide plating technique, Bondal, uses a surface activation procedure with a cyanide-free zincate solution and copper strike prior to tin plating.

The samples also have been plated in three different periods during the life cycle of each bath solution, with a periodicity depending on the frequency of the suppliers' changing or readjustment of his baths. For example, if the supplier used a new bath every Monday, two bars have been taken every Monday, two bars every Wednesday and two bars every Friday. Samples have also been plated in three different positions in the bath.

SEM testing of the samples in these batches was used to define how well the quality of plating is reproduced with regard to bath age and positions of the parts in the bath. There are two tests to study the quality of the plating: the adhesion test and the thermal shock test.

1.6.4.1 Adhesion Test

The adhesion test should be conducted according to ISO 2819:1980, "Metallic Coatings on Metallic Substrates. Electrodeposited and Chemically Deposited Coatings. Review of Methods Available for Testing Adhesion." The adhesion test involves cross-cut and tape tests. It is first required to scribe down to the metal. A cutting blade with a straight edge is used to draw a square of 1 cm² divided into 100 squares (10 horizontal lines separated by 1 mm and crossed by 10 vertical lines). Then, an adhesive tape with peeling force >180 g/cm is applied on the surface and pulled off quickly. If there is any coating peeled away with the tape, the adhesion is considered as nonsatisfactory. Indeed, if the plating fails the adhesion test at a nonaged status, further tests are no longer necessary and the plating technique is considered as not meeting the specifications.

1.6.4.2 Thermal Shock Test

The tests should be conducted according to the International Standard ISO 2819, which determines the technique of the test. According to the standard the samples must be heated at the recommended temperature. They are then quickly thrown in room-temperature water. A temperature of 150°C is the recommended for tin plating over Al, Cu, Zn alloys and steel substrates. Samples are then examined. If the coating is blistering, peeling, or exfoliating, then the adhesion is considered as not satisfactory. According to the thermal shock test, the adhesion of tin plating on aluminum should not be strongly affected by short exposure to temperatures up to 200°C. For samples exposed to elevated temperature for a longer period of time, the adhesion of the plating begins to deteriorate. According to the Standard, scribing is applied to every sample before and after thermal shock.

1.6.4.3 Plating Techniques and Adhesion of Tin Plating on Al

All three plating techniques provide a good plating quality, according to the tests conducted in Ref. [70]. All three plating types succeeded adhesion and thermal shock tests. Original plating adhesion was found to be satisfactory for both Alstan techniques and the cyanide-free zincate technique Bondal. According to the results of scribing tests after thermal shock at 150°C, all samples plated using all three techniques passed the test and the coatings can be considered properly adhesive. In order to study the quality of the plating beyond the limit of 150°C, the thermal shock test was performed also at 200°C. After thermal shock at 200°C the surface had an iridescent purple tint. No change in the adhesiveness of the coating was observed.

1.6.4.4 Plating Techniques and the Quality of Tin Plating on Al

The quality of tin plating on aluminum is best determined by using SEM/EDS metallographic analysis. This analysis allows the measurement of the thickness of the tin plating and preplating layer (copper or bronze) and determines if pores, voids, and gaps are present along each interface (Al–Cu/bronze, Cu/bronze–Sn) of tin plating across the layer. With EDS chemical analysis, the chemical composition of copper/bronze preplating layer can be determined. For SEM study, the samples are usually encapsulated with an epoxy resin polymerizing at room temperature. It is to be noted that the polymerization process involves heating samples at 70°C for a few minutes, which is not supposed to affect the quality of the plating.

1.6.4.4.1 Tin on Al Plating Thickness

An example of using the SEM technique for measuring the plating and underplating thickness is given in Ref. [70]. Tin and bronze thickness measurements have been made on each SEM capsule, containing three parts of each bar: one part from the middle of the bar and two parts from the edges of the bar. Considering the differences between coating on the curved and linear sides, measures were taken on each side in three different places.

The average value of tin plating and underplating was determined for all three types of plating based on multiple measurements. It was found that in Alstan 80 plating the average thickness of tin plating was 13 μm and the bronze underplating thickness was 1.1 μm . In the case of Alstan 88 plating these values were 11 and 1.5 μm correspondingly. In the case of Bondal plating, the average thickness of tin plating is 5 μm and the thickness of the copper underplate is 1.0 μm .

A slight difference in thickness was observed between curved and linear sides. This well-known phenomenon is the result of differences in the electrical field. For all samples, including different plating bath life cycles, different positions in the bath, and different sides of the samples (linear or curved), tin plating thickness varied in the range between 7.1 and 13.9 μm . Bronze underplating thickness ranged between 0.7 and 1.5 μm . The thicknesses of both plating and underplating were in agreement with OEM specifications.

1.6.4.4.2 Morphology and Composition of Tin Plating on Aluminum

The composition and quality of samples for all three types of tin plating on Al were determined using SEM/EDS analysis in Ref. [69]. It was found that for Alstan 80

plating the upper layer of the plating consists of pure tin, and the underlayer is composed of Sn and Cu with the proportion corresponding to 70Sn30Cu-type bronze (70% Sn and 30% Cu) (Figure 1.9). An SEM microphotograph of the cross section of freshly plated Alstan 80 samples also shows that the quality of nonaged plating is good: no separation, voids, or cracks have been found. SEM analysis showed that Alstan 88 samples also had no pores, voids, or gaps along each interface (Al-bronze, bronze–Sn) (Figure 1.10). The quality of Bondal samples was also good: no pores, voids, or gaps were detected along each interface (Al–Cu, Cu–Sn).

The results of the tests in Ref. [70] show that all the three techniques of tin plating often used in the electrical industry provide good plating adhesion and a perfect quality of plating with no pores, voids, or gaps detected along each interface and with the

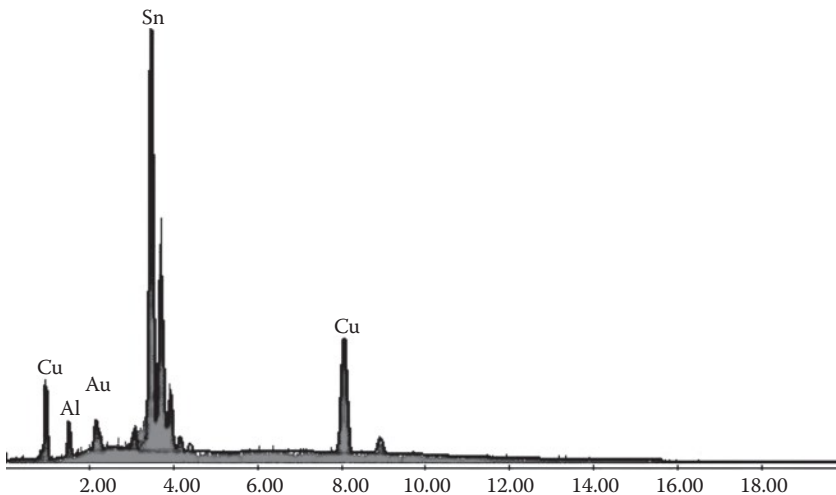


FIGURE 1.9 Composition of copper-bronze underplating in a freshly plated Alstan sample (70% Sn and 30% Cu).

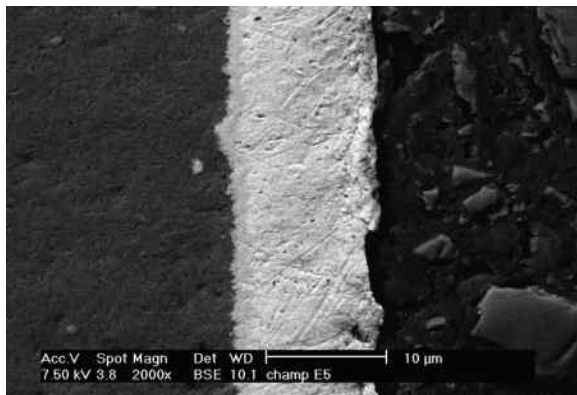


FIGURE 1.10 Microphotograph of freshly plated tin plating on Al with bronze underplating.

thickness of both plating and underplating in agreement with plating standards. It was also shown that the position of the samples in the bath and the age of the bath solution during the bath life cycle have little or no influence on the quality of tin plating on Al.

1.7 PLATING STANDARDS AND GLOSSARY

1.7.1 NATIONAL AND INTERNATIONAL STANDARDS AND REGULATIONS ON PLATING

The following national and international standards specify the requirements for various types of plating and different substrates and describe the conditions of the plating procedure that provides the best quality of the plating. Other Standards describe the procedures of testing the plating quality. Included are international regulations focused on environmental safety.

An example of what issues are covered on plating standards is given for ASTM B-545-97(2009). “Standard Specification for Electro-deposited Coatings of Tin” (The International Classification for Standards (ICS) Number Code 25.220.40 (Metallic coatings), ASTM International, 8pp., 2009):

This specification covers the requirements for electrodeposited tin coatings applied to metallic articles to provide a low contact resistance surface, to protect against corrosion, to facilitate soldering, to provide antigalling properties, and to be a stop-off coating in the nitriding of high-strength steels.

This specification does not cover hot-dipped tin or other nonelectrodeposited coatings, and mill products. Coatings shall be grouped into six service classes, which are based on the minimum thickness and severity of service required for the coating, and three surface appearance types, which are based on the type of electroplating process employed.

The surface appearance types are matte tin electrodeposits, bright tin electrodeposits, and flow-brightened electrodeposits. Coatings shall be sampled, tested and conform accordingly to specified requirements as to appearance, purity, local and mean thickness, integrity (including gross defects, mechanical damage, and porosity), adhesion, solderability, and hydrogen embrittlement relief.

Standards for Silver Plating:

- ASTM B 700-08, “Standard Specification for Electrodeposited Coatings of Silver for Engineering Use”
- MIL QQ-S-365D, “Federal Specification: Silver Plating, Electrodeposited, General Requirements for (03 June 1985) [S/S by ASTM-B700]”
- ISO 4521, “Metallic coatings—Electrodeposited silver and silver alloy coatings for engineering purposes”
- SAE AMS 2411G-2008 (SAE AMS 2411G-2008), “Plating, Silver for High-Temperature Applications”

Standards for Tin Plating:

- Mil-T-10727C Tin, “Plating: Electrodeposited or Hot-dipped (This specification has been cancelled, but is still in wide use)”

- ASTM B-545-97 (2009), “Standard Specification for Electro-deposited Coatings of Tin”
- ISO 2093-1986, “Electroplated Coatings of Tin: Specification and Test Methods”

Standards for Nickel Plating:

- SAE AMS-QQ-N-290B-2009 (SAE AMS-QQ-N-290B-2009), “Nickel Plating (Electrodeposited)”
- SAE AMS 2403, “Plating, Nickel, General Purpose (Reaffirmed: June 2009)”
- SAE AMS 2423D-2002 (SAE AMS 2423D-2002), “Plating, Nickel Hard Deposit (Reaffirmed: April 2007 and June 2009)”
- MIL-P-18317, “Plating, Black Nickel (Electrodeposited) On Brass, Bronze, or Steel”
- SAE AMS 2404F-2008 (SAE AMS 2404F-2008), “Plating, Electroless Nickel”

Standards for EN Plating:

- AMS 2404, “Electroless Nickel Plating”
- AMS 2405, “Electroless Nickel, Low-Phosphorus”
- ASTM B656, “Guide for Autocatalytic Nickel–Phosphorus Deposition on Metals for Engineering Use”
- ASTM B733, “Standard Specification for the Autocatalytic Nickel–Phosphorus Coatings on Metal Coatings”

Standards for Zinc Plating:

- ASTM F2329-05 (2011), “Standard Specification for Zinc Coating, Hot-Dip, Requirements for Application to Carbon and Alloy Steel Bolts, Screws, Washers, Nuts, and Special Threaded Fasteners”
- Phosphorus ASTM B852-08, “Standard Specification for Continuous Galvanizing Grade (CGG) Zinc Alloys for Hot-Dip Galvanizing of Sheet Steel”
- SAE AMS 2402J-2007 (SAE AMS2402J-2007), “Zinc Plating”

Standards for Galvanizing:

- ASTM A123/A123M-09, “Standard Specification for Zinc (Hot-Dip Galvanized) Coatings on Iron and Steel Products”
- ASTM A143/A143M-07, “Standard Practice for Safeguarding Against Embrittlement of Hot-Dip Galvanized Structural Steel Products and Procedure for Detecting Embrittlement”
- ASTM A384/A384M-07, “Standard Practice for Safeguarding Against Warpage and Distortion During Hot-Dip Galvanizing of Steel Assemblies”
- ASTM A780/A780M-09, “Standard Practice for Repair of Damaged and Uncoated Areas of Hot-Dip Galvanized Coatings”

Standards for Plating on Aluminum:

- ASTM Standard B253-87(2010), “Standard Guide for Preparation of Aluminum Alloys for Electroplating”
- SAE AMS 2420D-2002 (SAE AMS 2420D-2002), “Plating of Aluminum for Solderability Zinc Immersion Pre-treatment Process (Reaffirmed: November 2007)”

Standards for Plating Testing:

- SEMI G62-95 (Reapproved 0302), “Test Method for Silver Plating Quality”
- ISO 2819:1980, “Metallic coatings on metallic substrates. Electrodeposited and chemically deposited coatings. Review of methods available for testing adhesion”
- SAE AIR 4789B-2003 (SAE AIR 4789B-2003), “Aerospace Information Report on Evaluating Corrosion Testing of Electrical Connectors and Accessories for the Purpose of Qualification”

Regulations:

- Waste Electrical and Electronic Equipment (WEEE)
- RoHS, European directive 2002/95/CE (RoHS directive) of the European Parliament and the European Union Council
- ANSI/ITAA GEIA-STD-0005-2, “Standard for Mitigating the Effects of Tin Whiskers in Aerospace and High Performance Electronic Systems”

1.8 PLATING GLOSSARY

Plating terminology is very extensive, and having an explanation of plating terms at hand when reading a paper or book on plating is very useful. The following glossary may not cover all the terms used in the plating industry and technology, but will be very helpful while reading this book. The source of this glossary is “Glossary of Finishing Terms.” <http://www.techplate.com/platingglossary1.htm>, reprinted with permission.

A

Abrasive blasting: A process for cleaning or finishing by a means of an abrasive directed at the work piece at differing pressures and velocities.

Activation: Elimination of a passive condition on a surface.

Activity (ion): The ion concentration corrected for deviations from ideal behavior. Concentration multiplied by activity coefficient.

Addition agent: A material added in small quantities to a solution to modify its characteristics. It is usually added to a plating solution for the purpose of modifying the character of a deposit.

Adhesion: The attractive force that exists between an electrodeposit and its substrate that can be measured as the force required to separate an electrodeposit and its substrate.

Amorphous: Noncrystalline, or devoid of regular structure.

Ampere: The current that will deposit silver at the rate of 0.0011180 g/s. Current flowing at the rate of 1 Coulomb/s.

Angstrom unit (Å): 10^{-8} cm.

Anion: A negatively charged ion.

Anode: The electrode in electrolysis, at which negative ions are discharged, positive ions are formed, or other oxidizing reactions occur.

Anode efficiency: Current efficiency of a specified anodic process.

Anode film: (1) The layer of solution in contact with the anode that differs in composition from that of the bulk of the solution. (2) The outer layer of the anode itself consisting of oxidation or reaction products of the anode metal.

Anode polarization: See polarization.

Anodic coating: A protective, decorative, or functional coating, formed by the conversion of the surface of a metal in an electrolytic oxidation process.

Anodizing: An electrolytic oxidation process in which the surface of a metal, when anodic, is converted into a coating having desirable protective, decorative, or functional properties.

Anolyte: The portion of electrolyte in the vicinity of the anode; in a divided cell, the portion of electrolyte on the anode side of the diaphragm.

Antipitting agent: An addition agent for the specific purpose of preventing gas pits in a deposit.

Automatic machine (or conveyor): A machine for mechanically processing parts through treatment cycles, such as cleaning, anodizing, or plating.

Automatic plating: (1) Full: Plating in which the cathodes are automatically conveyed through successive cleaning and plating tanks. (2) Semi: Plating in which the cathodes are conveyed automatically through only one plating tank.

B

Back EMF (electromotive force): The potential set up in an electrolytic cell that opposes the flow of current, caused by such factors as concentration polarization and electrode films. See EMF.

Barrel burnishing: The smoothing of surfaces by means of tumbling the work in rotating barrels in the presence of metallic or ceramic shot, and in the absence of abrasive. In a ball burnishing, the shot consists of hardened steel balls.

Barrel finishing (or tumbling): Bulk processing in barrels, in either the presence or absence of abrasives or burnishing shot, for the purpose of improving the surface finish.

Barrel plating (or cleaning): Plating or cleaning in which the work is processed in bulk in a rotating container.

Base metal: A metal that readily oxidizes or dissolves to form ions. The opposite of noble metal.

Basis metal (or material): Material upon which coatings are deposited.

Bipolar electrode: An electrode that is not directly connected to the power supply but is so placed in the solution between the anode and the cathode that the

part closest to the anode becomes cathodic and the part closest to the cathode becomes anodic.

Blue dip: A solution, once widely used, containing a mercury compound used to deposit mercury upon a metal by immersion, usually prior to silver plating.

Bright dip (nonelectrolytic): A solution used to produce a bright surface on a metal.

Bright plating: A process that produces an electrodeposit having a high degree of specular reflectance in as-plated condition.

Bright plating range: The range of current densities within which a given plating solution produces a bright plate.

Brightener: An addition agent that leads to the formation of a bright plate, or that improves the brightness of the deposit.

Brush plating: A method of plating in which the plating solution is applied with a pad or brush, within which is an anode and which is moved over the cathode to be plated.

Buffer: A compound or mixture that, when contained in the solution, causes the solution to resist changes in the pH. Each buffer has a characteristic limited range of pH values over which it is effective.

Buffing: The smoothing of a surface by means of a rotating flexible wheel to the surface of which fine, abrasive particles are applied in liquid suspension, paste, or grease stick form.

Building up: Electroplating for the purpose of increasing the dimensions of an article.

Burnishing: The smoothing of surfaces by rubbing, accomplished chiefly by the movement rather than removal of the surface layer.

Burnt deposit: A rough, noncoherent, or otherwise unsatisfactory deposit produced by the application of an excessive current density (CD) and usually containing oxides or other inclusions.

Bus (busbar): A rigid conducting section for carrying current to the anode and cathode bars.

Butler finish: A finish composed of fine, uniformly distributed parallel lines, having a characteristic luster usually produced by rotating wire brushes or cloth wheels with applied abrasives.

C

Cathode: The electrode in an electrolysis at which positive ions are discharged, negative ions are formed, or other reducing actions occur.

Cathode efficiency: The current efficiency of a specified cathodic process.

Cathode film: The layer of solution in contact with the cathode that differs in composition from that of the bulk of the solution.

Catholyte: The portion of the electrolyte in the vicinity of the cathode; in a divided cell, the portion on the cathode side of the diaphragm.

Cation: A positively charged ion.

Chemical polishing: The improvement in smoothness of a metal by simple immersion in a suitable solution. See Bright dip (nonelectrolytic).

Cleaning: The removal of grease or other foreign material from a surface.

Alkaline cleaning: Cleaning by means of alkaline solutions.

Anodic or reverse cleaning: Electrolytic cleaning in which the work is the anode.

Cathodic or direct cleaning: Electrolytic cleaning in which the work is the cathode.

Diphase cleaning: Cleaning by means of a solution that contains a solvent layer and an aqueous layer. Cleaning is effected both by solvent and by emulsifying action.

DC cleaning: See cathodic or direct cleaning.

Electrolytic cleansing: Alkaline cleaning in which a current is passed through the solution, the work being one of the electrodes.

Immersion: see Soak cleaning.

Reverse current cleaning: See Anodic or reverse cleaning.

Soak cleaning: Cleaning by immersion without the use of current, usually in an alkaline solution.

Solvent cleaning: Cleaning by means of organic solvents.

Spray cleaning: Cleaning by means of spraying.

Ultrasonic cleaning: Cleaning by any chemical means aided by ultrasonic energy.

Colloidal particle: An electrically charged particle, generally smaller in size than 200 m μ , dispersed in a second continuous phase.

Coloring: (1) The production of desired colors on metal surfaces by appropriate chemical or electrolytical action. (2) Light buffing of metal surfaces for the purpose of producing a high luster.

Composite plate: An electrodeposit consisting of two or more layers of metal deposited successively.

Conductance: The capacity of a medium, usually expressed in mhos, for transmitting electric current. The reciprocal of resistance.

Conducting salt: A salt added to the solution in order to increase its conductivity.

Conductivity: Specific conductance—The current transferred across unit area per unit potential gradient. In the metric system, K = amperes per squared centimeters divided by volts per centimeter. The reciprocal of resistivity.

Contact plating: Deposition of a metal by the use of an internal source of current by immersion of the work in solution in contact with another metal.

Contact potential: The potential difference at the junction of two dissimilar substances.

Conversion coating: A coating produced by chemical or electrochemical treatment of a metal solution that gives a superficial layer containing a compound of the metal, for example, chromate coatings on zinc and cadmium, oxide coating on steel.

Coulomb: The quantity of electricity that is transmitted through an electric circuit in 1 s when the current in the circuit is 1 amp. The quantity of electricity that will deposit 0.0011180 g of silver.

Critical current density: A CD above which a new and sometimes undesirable reaction occurs.

Current density (CD): Current per unit area.

Current efficiency: The proportion, usually expressed as a percentage, of the current that is effective in carrying out a specified process in accordance with Faraday's law.

Cutting down: Polishing or buffing for the purpose of roughness or irregularities.

D

Deburring: The removal of burrs, sharp edges, or fins by mechanical, chemical, or electrochemical means.

Decomposition potential: The minimum potential, exclusive of IR drop, at which an electrochemical process can take place at an appreciable rate.

Degreasing: The removal of grease and oils from a surface.

Solvent degreasing: Degreasing by immersion in liquid organic solvent.

Vapor degreasing: Degreasing by solvent vapors condensing on the parts being cleaned.

Deionization: The removal of ions from a solution by ion exchange.

Depolarization: A decrease in polarization of an electrode at a specified CD.

Depolarizer: A substance or a means that produces depolarization.

Detergent: A surface active agent that possesses the ability to clean soiled surfaces.

Anionic detergent: A detergent that produces aggregates of negatively charged ions with colloidal properties.

Cationic detergent: A detergent that produces aggregates of positively charged ions with colloidal properties.

Nonionic detergent: A detergent that produces aggregates of electrically neutral molecules with colloidal properties.

Diaphragm: A porous or permeable membrane separating the anode and cathode compartments of an electrolytic cell from each other or from an intermediate compartment.

Diffusion coating: An alloy coating produced by applying heat to one or more coatings deposited on a basis metal.

Dispersing agent: A substance that increases the stability of a suspension by retarding the flocculation.

E

Electrochemical equivalent: The weight of an element, compound, radical, or ion involved in a specified electrochemical reaction during the passage of unit quantity of electricity, such as a Faraday, ampere-hour, or coulomb.

Electrochemistry: The branch of science and technology that deals with transformations between chemical and electrical energy.

Electrode: A conductor through which current enters or leaves an electrolytic cell, at which there is a change from conduction by electrons to conduction by charged particles of matter, or vice versa.

Electrodeposition: The process of depositing a substance upon an electrode by electrolysis.

Electrode potential (EP): The difference in potential between an electrode and the immediately adjacent electrolyte referred to some standard EP as zero.

Dynamic EP: The EP measured when a current is passing between the electrode and the electrolyte.

Equilibrium EP: A static EP when the electrode and the electrolyte are in equilibrium with respect to a specified electrochemical reaction.

Static EP: The EP measured when no net current is flowing between the electrode and the electrolyte.

Standard EP: An equilibrium EP for an electrode in contact with an electrolyte in which all of the components of a specified chemical reaction are in their standard states. The standard state for an ionic constituent is unit ion activity.

Electroforming: The production or reproduction of articles by electrodeposition upon a mandrel or mold that is subsequently separated from the deposit.

Electrogalvanizing: Electrodeposition of zinc coatings.

Electroless plating: Deposition of a metallic coating by a controlled chemical reduction that is catalyzed by the metal or alloy being deposited.

Electrolyte: (1) A conducting medium in which the flow of current is accompanied by the movement of matter. Most often an aqueous solution of acids, bases, or salts, but includes many other media, such as fused salts, ionized gases, some solids, and so on. (2) A substance that is capable of forming a conducting liquid medium when dissolved or melted.

Electrolysis: Production of chemical changes by the passage of a current through an electrolyte.

Electrolytic cell: A unit apparatus in which electrochemical reactions are produced by applying electrical energy, or which supplies electrical energy as a result of chemical reactions and which includes two or more electrodes and one or more electrolytes contained in a suitable vessel.

Electromotive series: A table that lists in order the standard electrode potentials of specified chemical reactions.

Electrophoresis: The movement of colloidal particles produced by the application of an electric potential.

Electroplating: The electrodeposition of an adherent metallic coating upon an electrode for the purpose of securing a surface with properties or dimensions different from those of the basis metal.

Electropolishing: The improvement in surface finish of a metal, effected by making it anodic in an appropriate solution.

Electrorefining: The process of anodically dissolving a metal from an impure anode and depositing it cathodically in a purer form.

Electrotyping: The production of printing plates by electroforming.

Electrowinning: The production of metals by electrolysis with insoluble anodes in solutions derived from ores or other materials.

Embrittlement, hydrogen: See Hydrogen embrittlement.

EMF (electromotive force): An electrical potential.

Emulsion: A suspension of small droplets of one liquid in another in which it is insoluble. For the formation of a stable emulsion, an emulsifying agent must usually be present.

Emulsifying agent: A substance that increases the stability of an emulsion.

Energy efficiency: The product of the current efficiency and the voltage efficiency for a specified electrochemical process.

Equivalent conductivity: In an electrolyte, the conductivity of the solution divided by the number of equivalents of conducting solute per unit volume, that is, the conductivity divided by the normality of the solution.

Etch (n): A roughened surface produced by a chemical or electrochemical means.

Etch (v): To dissolve unevenly (or uniformly) a part of the surface of a metal.

F

Faraday: The number of coulombs (96,490) required for an electrochemical reaction involving one chemical equivalent.

Ferritic stainless steel: Ferritic stainless steels are chromium alloys with a low carbon content. They are magnetic and have a good ductility, plus resistance to corrosion and oxidation (they are especially resistant to stress corrosion cracking).

Filter aid: An inert, insoluble material, more or less finely divided, used as a filter medium or to assist in filtration by preventing excessive packing of the filter cake.

Flash (or flash plate): A thin electrodeposit, $<1 \mu\text{m}$. See Strike.

Flocculate: To aggregate into larger particles, to increase in size to the point where precipitation occurs.

Formula weight: The weight, in grams, pounds, or other units, obtained by adding the atomic weights of all elemental constituents in a chemical formula.

Free cyanide: (1) True: The actual concentration of cyanide radical, or equivalent alkali cyanide not combined in complex ions with metals in the solution. (2) Calculated: The concentration of cyanide, or alkali cyanide, present in the solution in excess of that calculated to be necessary for forming a specified complex ion with a metal or metals present in the solution. (3) Analytical free cyanide content of a solution, as determined by a specified analytical method.

G

Galvanic cell: An electrolytic cell capable of producing electrical energy by electrochemical action.

Galvanic series: A list of metals and alloys arranged according to their relative potentials in a given environment. See Electromotive series.

Galvanizing: Application of a coating of zinc.

Gassing: The evolution of gases from one or more of the electrodes during electrolysis.

Glass electrode: A half-cell in which the potential measurements are made through a glass membrane.

Grinding: The removal of metal by means of a rotating rigid wheel containing abrasive.

Grit blasting: Abrasive blasting with small irregular pieces of steel or malleable cast iron.

H

Half cell: An electrode immersed in a suitable electrolyte. It may be designed to yield a known constant potential, in which case unknown potentials may be measured against it, for example, the calomel half cell.

Hard chromium: Chromium plated for engineering rather than decorative applications. Not necessarily harder than the latter.

Haring cell: A rectangular box of nonconducting material, with principal and auxiliary electrodes so arranged as to permit estimation of the throwing power of electrode polarizations and potentials between them.

High lights: Those portions of a metal article most exposed to buffing or operations and, hence, having the highest luster.

Hull cell: A trapezoidal box of nonconducting material with electrodes arranged to permit observation of cathodic or anodic effects over a wide range of current densities.

Hydrogen embrittlement: Embrittlement of a metal or alloy caused by absorption of hydrogen during a pickling, cleaning, or plating process.

Hydrogen overvoltage: Overvoltage associated with the liberation of hydrogen.

Hydrophilic: (1) Tending to absorb water. (2) Tending to concentrate in an aqueous phase.

Hydrophobic: (1) Tending to repel water. (2) Lacking affinity for water.

I

Immersion plate: A metallic deposit produced by a displacement reaction in which one metal displaces another from the solution, for example, $\text{Fe} + \text{Cu}^{2+} \rightarrow \text{Cu} + \text{Fe}^{2+}$ (copper replacing iron).

Indicator (pH): A substance that changes color when the pH of the medium is changed. In the case of most useful indicators, the pH range within which the color changes is narrow.

Inert anode: An anode that is insoluble in an electrolyte under the conditions prevailing in the electrolysis.

Inhibitor: A substance used to reduce the rate of a chemical or electrochemical reaction, commonly corrosion or pickling.

Interfacial tension: The contractile force of an interface between two phases. See Surface tension.

Ion: A charged portion of matter of atomic or molecular dimensions.

Ion exchange: An exchange of ions between a solution and a solid. In practice, it is most commonly effected by ion exchange resins.

IR drop: The voltage across a resistance in accordance with Ohm's law: $E = IR$ where: E = potential (voltage), I = current, and R = resistance.

K–L

Karat: A 24th part by weight; thus 18-karat gold is 18/24 pure.

Lapping: Rubbing two surfaces together, with or without abrasives, for the purpose of obtaining an extreme dimensional accuracy or superior surface finish.

Leveling action: The ability of a plating solution to produce a surface smoother than that of the substrate.

Limiting current density: (1) Cathodic: The maximum CD at which satisfactory deposits can be obtained. (2) Anodic: The maximum CD at which the anode behaves normally, without excessive polarization.

M

Mat finish (matte finish): A dull finish.

Matrix: A form used as a cathode in an electroforming; a mold or mandrel.

Metal distribution ratio: The ratio of the thicknesses of metal upon two specified areas of a cathode. See Throwing power.

Metalizing: (1) The application of an electrically conductive metallic layer to the surface of nonconductors. (2) The application of metallic coatings by nonelectrolytic procedures such as spraying of molten metal and deposition from the vapor phase.

Microinch: One-millionth of an inch, 0.000001 in. = 0.001 mil.

Micron (μ): One-millionth of a meter, 0.001 mm

Microthrowing power: The ability of a plating solution or a specified set of plating conditions to deposit metal in pores or scratches.

Mil: One-thousandth of an inch, 0.001 in. = 25.4 μ .

Mill scale: The heavy oxide layer formed during hot fabrication or heat treatment of metals.

Motor-generator (MG set): A machine that consists of one or more motors mechanically coupled to one or more generators. In plating such a machine, the generator delivers DC of appropriate amperage and voltage.

N–O

Noble metal: A metal that does not readily tend to furnish ions, and therefore does not dissolve readily, nor easily enters into reactions such as oxidation and so on. The opposite of base metal.

Note—Since there is no agreement on the sign of electrode potentials, the words “noble” and “base” are often preferred because they are unambiguous.

Nodule: A rounded projection formed on a cathode during electrodeposition.

Orange peel: A finish resembling the dimpled appearance of an orange peel.

Overvoltage: The irreversible excess of potential required for an electrochemical reaction to proceed actively at a specified electrode, over and above the reversible potential characteristics of that reaction.

Oxidation: A reaction in which electrons are removed from a reactant.

Oxidizing agent: A compound that causes oxidation, thereby itself becoming reduced.

P

pH: A unit of measure depicting the hydrogen concentration of a solution: Scale 1–14, where 7 is neutral; <7—acidic; >7—basic.

Passivity: The condition of a metal that retards its normal reaction in a specified environment and is associated with the assumption of a potential more noble than its normal potential.

Peeling: The detachment or partial detachment of an electrodeposited coating from a basis metal or undercoat.

- Periodic reverse plating:** A method of plating in which the current is reversed periodically. The cycles are usually no longer than a few minutes and may be much less.
- Pickle:** An acid solution used to remove oxides or other compounds from the surface of a metal by chemical or electrochemical action.
- Pickling:** The removal of oxides or other compounds from a metal surface by means of a pickle.
- Pit:** A small depression or cavity produced in metal surface during electrodeposition or by corrosion.
- Plastisol:** A mixture of resins, plasticizers, and other minor additives, such as pigments and so on, that can be converted into a continuous film by the application of heat. Distinct from baking enamels and so on, in which all of the original mixture becomes a part of the film; there is no significant evaporation of the solvent. The films are usually much thicker than obtainable from coatings which depend on the evaporation of a volatile solvent.
- Plating range:** The CD range over which a satisfactory electroplate can be deposited.
- Polarization:** The change in the potential of an electrode during electrolysis, such that the potential of an anode always becomes more noble and that of a cathode becomes less noble than their respective static potentials. Equal to the difference between the static potential and the dynamic potential.
- Polarizer:** A substance or a means that produces or increases polarization.
- Polishing:** The smoothing of a metal surface by means of the action of abrasive particles attached by adhesive to the surface of wheels or endless belts usually driven at a high speed.
- Primary current distribution:** The distribution of the current over the surface of an electrode in the absence of polarization.

R

- Rack, plating:** A frame for suspending and carrying current to articles during plating and related operations.
- Rectification:** The conversion of alternating current (AC) into direct current (DC).
- Rectifier:** A device that converts AC into DC by virtue of a characteristic permitting appreciable flow of current in only one direction.
- Reducing agent:** A compound that causes reduction, thereby itself becoming oxidized.
- Reduction:** A reaction in which electrons are added to a reactant. More specifically, the addition of hydrogen or the abstraction of oxygen. Such a reaction takes place, for example, at the cathode in electrolysis.
- Relieving:** The removal of material from selected portions of a colored metal surface by mechanical means, to achieve a multicolored effect.
- Resist, n:** (1) A material applied to a part of a cathode or plating rack to render the surface nonconductive. (2) A material applied to a part of the surface of an article to prevent reaction of metal from that area during chemical or electrochemical processes.
- Ripple (DC):** Regular modulations in DC output wave of a rectifier unit, or a motor-generator set, originating from the harmonics of the AC input system in the

case of a rectifier, or from the harmonics of the induced voltage of a motor generator set.

S

Sacrificial protection: The form of corrosion protection wherein one metal corrodes in preference to another, thereby protecting the latter from corrosion.

Sand blasting: Abrasive blasting with sand.

Saponification: The alkaline hydrolysis of fats whereby soap is formed; more generally, the hydrolysis of an ester by an alkali with the formation of an alcohol and a salt of the acid portion.

Satin finish: A surface finish that behaves as a diffuse reflector and which is lustrous but not mirror-like.

Scale: An adherent oxide coating that is thicker than the superficial film referred to as tarnish.

Sealing of anodic coating: A process that, by absorption, chemical reaction, or other mechanisms, increases the resistance of an anodic coating to staining and corrosion, improves the durability of colors produced in the coating, or imparts other desirable properties.

Sequestering agent: A sequestering agent forms soluble complex ions with, or sequesters, a simple ion, thereby suppressing the activity of that ion. Thus, in a water treatment, the effects of hardness can be suppressed by adding agents to sequester calcium and magnesium. See *Chelating Agent*.

Shield (n): A nonconducting medium for altering the current distribution on an anode or cathode.

Shield (v): To alter the normal current distribution on an anode or cathode by the interposition of a nonconductor.

Slurry: A suspension of solids in water.

Spotting out: The delayed appearance of spots and blemishes on plated or finished surfaces.

Stalagmometer: An apparatus for determining the surface tension. The mass of a drop of liquid is measured by weighing a known number of drops or by counting the number of drops obtained from a given volume of the liquid.

Stray current: Current through paths other than the intended circuit, such as through heating coils or the tank.

Strike (n): (1) A thin film of metal to be followed by other coatings. (2) A solution used to deposit a strike.

Strike (v): (1) To remove a coating from the basis metal or undercoat. (2) To plate for a short time, usually at a high initial CD.

Strip: A process or solution used for the removal of a coating from a basis metal or an undercoat.

Substrate: See Basis metal (or material).

Superimposed AC: A form of current in which an alternating current component is superimposed on the direct plating current.

Surface active agent (surfactant): A soluble or colloidal substance having the property of affecting markedly the surface energy of solutions even when present in a very low concentration.

Surface tension: That property, due to molecular forces, that exists in the surface film of all liquids and tends to prevent the liquid from spreading.

T

Tank voltage: The total voltage between the anode and cathode of a plating bath or electrolytic cell during electrolysis. It is equal to the sum of: (1) the equilibrium reaction potential, (2) the IR drop, and (3) the electrode potentials.

Tarnish: The dulling, staining, or discoloration of metals due to superficial corrosion. The film so formed.

Thief (or robber): An auxiliary cathode so placed as to divert to itself some current from portions of the work which would otherwise receive too high CD.

Throwing power: The improvement of the coating (usually metal) distribution over the primary current distribution on an electrode (usually cathode) in a given solution, under specified conditions. The term may also be used for anodic processes for which the definition is analogous.

Total cyanide: The total content of cyanide expressed as the radical CN^- , or alkali cyanide, whether present as simple or as complex ions.

Transference (or transport or migration): The movement of ions through the electrolyte associated with the passage of the electric current.

Transference number (transport number): The proportion of the total current carried by the ions of a given kind.

Trees: Branched or irregular projections formed on a cathode during electrodeposition, especially at edges and other high-CD areas.

Tripoli: Friable and dust-like silica used as an abrasive.

Tumbling: See Barrel finishing.

V-W

Voltage efficiency: The ratio, usually expressed as a percentage, of the equilibrium reaction potential in a given electrochemical process to the bath voltage.

Water break: The appearance of a discontinuous film of water on a surface signifying nonuniform wetting and usually associated with a surface contamination.

Wet blasting: A process for cleaning or finishing by means of a slurry or abrasive in water directed at high velocity against the work pieces.

Wetting agent: A substance that reduces the surface tension of a liquid, thereby causing it to spread more readily on a solid surface.

Whiskers: Metallic filamentary growths, often microscopic, sometimes formed during electrodeposition and sometimes spontaneously during storage or service, after finishing.

Work (plating): The material being plated or otherwise finished.

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2 Detrimental Processes and Aging of Plating

2.1 ISSUES OF TIN PLATING PERFORMANCE

2.1.1 GENERAL PRECAUTIONS IN USING TIN PLATING

Tin is a very good electrical conductor, but when applying tin to electrical contacts and other conductive parts it is recommended to take several precautions due to the specific physical properties of tin (Section 1.1). These precautions are summarized in the so-called “Tin Commandments” [1,2]:

1. Tin-coated contacts should be mechanically stable in the mated condition
2. Tin-coated contacts need at least 100 g contact normal force
3. Tin-coated contacts need lubrication
4. Tin coating is not recommended for continuous service at high temperatures
5. The choice of plated, reflowed, hot air leveled, or hot tin dipped coating does not strongly affect the electrical performance of tin or tin alloy-coated contacts
6. Electroplated tin coatings should be at least $2.5\text{ }\mu\text{m}$ ($\sim 100\text{ }\mu\text{in.}$) thick
7. Mating tin-coated contacts to gold-coated contacts is not recommended
8. Sliding or wiping action during contact engagement is recommended with tin-coated contacts
9. Tin-coated contacts should not be used to make or break current
10. Tin-coated contacts can be used under dry circuit or low level conditions

2.1.1.1 Tin and Fretting Corrosion

Tin plating is susceptible to a so-called fretting corrosion, which will be described later in Section 2.5. However, protective lubrication is necessary when it is not possible to achieve a mechanical stability. Application of a thin liquid lubricant film protects the contact surfaces from detrimental effects of disturbance or fretting motions. When a lubricant is applied, friction and generation of wear particles due to the motion are reduced and the surface is protected from an atmospheric oxidation, in and around the contact interface.

A lubricant can act to reduce wear, seal off the interface from the environment, and/or inhibit corrosion of the interface material when it is exposed to the fretting action. It becomes more important for lubrication to be used to prevent fretting corrosion when contact forces approach the minimum recommended level of 100 g (3.53 ounces). On the other hand, with higher contact forces lubrication may be

necessary to reduce friction and wear during insertion cycling of the connector [3]. In this respect, lubrication would permit the use of higher contact forces.

Lubrication may be applied to only one side of a connector pair. However, it is recommended that both sides be lubricated whenever possible. Sufficient lubricant is normally transferred during engagement of the connector to provide fretting corrosion resistance to a contact.

Lubricant formulations vary in complexity and effectiveness. They include pure mineral oil (marginal in life and effectiveness) and sophisticated mixtures of natural oils, synthetic oils, and additives for optimized performance. When possible, it is recommended to choose a lubricant with proven antifretting characteristics. A more detailed account of thoroughly tested lubricants that may reduce a negative effect of fretting corrosion is given in Section 4.4.

There are instances when the presence of a lubricant cannot be maintained throughout the lifetime of the connector. In these cases an alternative to lubrication such as a mechanically stable design or a noble metal coating should be considered.

2.1.1.2 Tin and Intermetallic Compounds

Tin plating is not recommended for continuous service at high temperature [4]. At elevated temperature, the performance of tin-coated electrical contacts is degraded by the aging effects due to a rapid increase in the diffusion rate of copper and tin. This results in a change in the composition and effective thickness of the tin coating as a hard, brittle, nonuniform resistive layer of copper–tin intermetallic compound (IMC) that grows between the tin layer and the copper base metal. More information about IMC is given in Section 2.5.

The use of nickel underplating is recommended for elevated temperature applications. It does not prevent the formation of IMC because nickel–tin IMC may grow as well. However, the growth rate of the nickel–tin IMC is lower than that of the copper–tin IMC, which results in lesser degree of degradation. The same underplating was found useful in mitigating deterioration of tin plating on aluminum at elevated temperatures (see Section 2.3).

In addition to the detrimental effects of IMC, tin loses a significant portion of its mechanical strength, resulting in substantial creep effects at temperatures $>100^{\circ}\text{C}$ (212°F). Special design parameters such as a high contact force, thick coatings, or limited time–temperature exposure are needed to successfully avoid contact problems.

High-temperature operation would impose special requirements on contact lubricants, and under this condition, the lubricant must withstand the time and temperature requirements representative of the applications. While tin-coated contacts have been used at higher temperatures on an intermittent basis, for example, high force contacts for automotive applications, using tin at temperatures $>100^{\circ}\text{C}$ (212°F) should be based on evaluation to verify the acceptable performance for the intended application.

2.1.2 THERMAL DETERIORATION OF TIN PLATING ON ALUMINUM

Tin-plated aluminum bus bars are often used in electrical applications as a cost-effective replacement of more expensive tin-plated copper. Elastic connections made

to tin-plated aluminum conductors are very commonly used in electrical distribution equipment. These connection jaws or clips are usually made of plated copper, which plug on to tin-plated aluminum or copper conductors.

However, the use of tin-plated Al bus bars in a plug-on jaw to bus bar connection may eventually lead to arcing and thermal failure. The history of elastic connections across the industry indicates a substantially higher occurrence of connection degradation in elastic connections to aluminum bus bars than to copper bus bars. The connection failure happens as a result of unstable contact resistance (CR) growth. This instability in a CR can be a result of chemical or physical changes in the plating, which are caused and accelerated by the high temperatures, which the connection may experience in carrying different loads. The degradation of the contact can lead to high CR, which can become large enough to cause contact arcing and melting.

The history of the failures of aluminum-to-copper connections is extensive, although tin is still one of the most common commercial plating for aluminum to improve the stability and decrease the galvanic corrosion of aluminum-to-copper connection [5]. Though the mechanisms of failure are not fully understood and explained, numerous processes such as oxidation, stress relaxation, differential thermal expansion, galvanic and fretting corrosion are attributed to degradation of the contacting interface and a corresponding change in CR [6,7].

2.1.2.1 Accelerated Aging Study of Tin Plating

Degradation of tin and tin alloy plating on copper was studied in many aspects due to the formation of copper–tin (CuSn) IMC, particularly at elevated temperatures [8,9]. On the other hand, the behavior of tin plating on aluminum was not studied well enough to identify the longevity of the plating exposed to elevated temperatures in electrical connections. The possible causes of occasional resistance growth in elastic connections to tin-plated aluminum bus bar conductors may be determined by studying the quality of tin plating on aluminum in the as-plated condition and after exposure to an elevated temperature in an accelerated aging study.

The first step in the study, however, should be learning about all aspects of the plating quality before elevated temperatures would be applied. The details of all three tin plating techniques on Al (Alstan 80, Alstan 88, and Bondal) used in this study are given in Section 1.6. According to the results of Ref. [10], all three tested plating techniques produce plating with good adhesion, and demonstrate the absence of the void, gaps, or cracks in the plating. Strong adhesion quality was found after a short exposure to 200°C (below the Sn melting temperature) with a thermal shock test that reveals any adhesion issues. These results are consistent with a strong adhesion of both the plating and the underplating over the aluminum bus bar. Therefore, freshly plated tin on aluminum usually does not show any defects that may lead to the failure.

However, various types of tin plating on aluminum traditionally used in electrical industry may deteriorate and eventually fail if exposed to elevated temperatures for prolonged periods of time. Multiple testing techniques, such as the adhesion test, thermal shock test, SEM metallography, EDS x-ray analysis, and thickness measurements [10], have been used to investigate three different types of tin plating over Al. This study allowed finding out whether exposure to high temperature affects the adhesion and the quality of tin plating on aluminum. Aluminum bus bars plated

with tin using three different traditional plating techniques have been exposed to elevated temperature for 1–8 weeks. The plated Al bus bars have been positioned in a classical oven at the temperature of ambient air stabilized at 150°C. After a specified period of time, one randomly selected bar was removed from the oven and the samples were cut and prepared for further testing. Aging test for Alstan 80 plating lasted for 8 weeks and the testing of plating quality was then performed after 1, 4, and 8 weeks of thermal exposure. For two other types of plating (Alstan 88 and Bondal), a more detailed aging process was studied, with the bars removed from the chamber after each week of exposure during the first 4 weeks.

2.1.2.2 Quality of Thermally Aged Tin Plating

Two tests may help us to determine the quality of the plating: the adhesion test and the thermal shock test. A description of these tests is given in Section 1.6. According to thermal shock test results, the adhesion of tin plating on aluminum was not significantly affected by short exposure to temperatures up to 200°C.

However, for samples exposed to elevated temperature for a longer period of time, the adhesion of the plating begins to deteriorate. Adhesion tests were performed on the samples of the Al bus bar with three different tin plating techniques after the aging tests. Alstan 80 samples failed adhesion tests after just 1 week of thermal exposure (Figure 2.1) and Alstan 88 samples failed adhesion tests after 4 weeks of thermal exposure. However, Bondal samples passed adhesion tests after 4 weeks of thermal exposure. According to the results of the scribing test the Bondal plating survived a longer exposure to high temperature than both Alstan 80 and Alstan 88 plating.

The quality of thermally aged tin plating on aluminum was compared to the original quality of the plating based on SEM metallographic analysis in Ref. [10]. This technique allows one to measure the thickness of tin plating and preplating layers (copper or bronze) and to find out whether pores, voids, and gaps are present along each interface (Al–Cu/bronze, Cu/bronze–Sn) of tin plating across the layer. Chemical analysis using the EDS technique defines the chemical composition of every layer on the sample surface, including copper or bronze preplating layers.

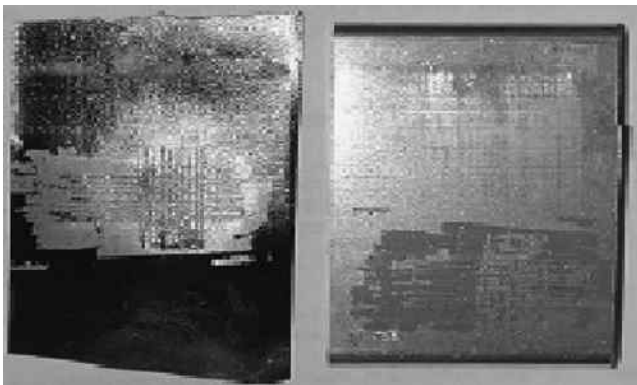


FIGURE 2.1 The appearance of tin plating on Al that failed the adhesion test.

In freshly plated Alstan 80 tin, the upper layer of the plating consists of pure tin, and the underlayer is composed of Sn and Cu with the proportion corresponding to 70Sn30Cu-type bronze (70% Sn and 30% Cu). The quality of nonaged plating is good without separation, voids, or cracks. Nonaged Alstan 88 samples also had no pores, voids, or gaps along each interface (Al-bronze, bronze-Sn). The same was found for Bondal samples; the plating quality was good as well: no pores, voids, or gaps were detected along Al-Cu and Cu-Sn interfaces (see Section 1.6).

To determine how aging time affects the quality of the plating applied using three different plating techniques, an SEM study was conducted on the samples after different periods of the exposure to elevated temperatures [10]. It was found that after 1 week of thermal exposure none of the three types of tin plating had signs of deterioration; there were no pores, voids, or gaps.

However, all three types of tin plating on aluminum demonstrated serious deterioration after a longer exposure to elevated temperature. The first signs of aging appeared in Alstan plating after 2 weeks of exposure: some voids and gaps have been detected along both interfaces Al-bronze and bronze-Sn, and the coating is peeling in a few locations. After 3 weeks at 150°C, multiple pores, voids, and gaps were found along interfaces, and the coating was peeling in more locations. After 4 weeks of thermal exposure, both types of Alstan plating had multiple pores, voids, and gaps along each of the interfaces Al-bronze and bronze-Sn, and multiple locations with coating peeling (Figure 2.2).

Finally, after 5 weeks of exposure, Alstan plating was found to be in a very bad condition with cracks along each interface, separation and fractures of both plating and underplating.

As to Bondal plating, it survived longer; after 2 weeks of thermal exposure the plating was still in good condition without pores, voids, or gaps. However, after 3 weeks it also began to show signs of aging: some voids and gaps appeared along the interfaces Al-Cu and Cu-Sn. The coating was peeling in a few locations.

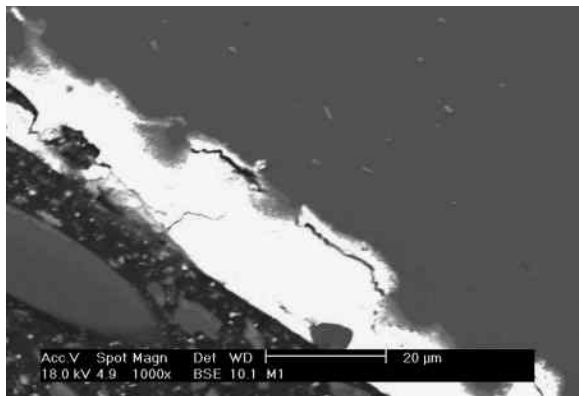


FIGURE 2.2 Microphotograph of tin plating on Al after 4 weeks of thermal aging: multiple pores and gaps along interfaces.

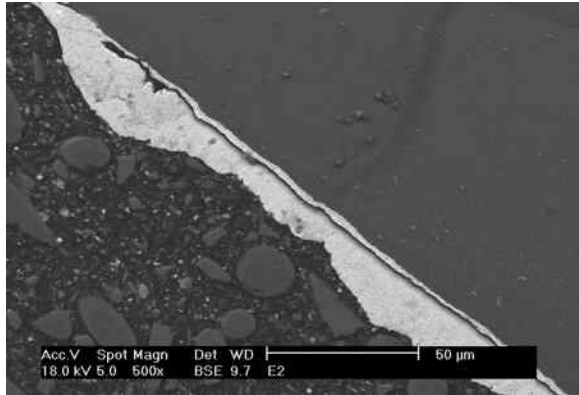


FIGURE 2.3 Microphotograph of tin plating on Al after 8 weeks of thermal aging: plating separated from base metal along interface.

The test revealed that after 4 weeks of thermal exposure, Bondal plating was no better than both Alstan types; it had multiple pores, voids, and gaps along interfaces, and multiple locations with coating peeling. The longest time of thermal exposure was 8 weeks, after which the cracks have progressed along each interface leading to separation of long parts of the plating. At the bronze–tin interface, cracks progression led to the fractures of long parts of tin plating (Figure 2.3).

From the results of the aging test in Ref. [10], it appears that the details and rate of deterioration may slightly differ for different plating procedures, but none of the plating was able to withstand the aging test. It was found that even though the Bondal plating survived the first 2 weeks of thermal exposure without significant deterioration, the aging process proceeded very fast for all three types of tin plating.

2.1.2.3 Mechanisms of Thermal Deterioration of Tin Plating on Al

It was suggested that theoretically at least three different mechanisms could cause deterioration of tin plating on aluminum during exposure to high temperature for an extended period of time [10]. These three mechanisms are: the different ability of the three materials (Sn, Cu or bronze, and Al) to expand at elevated temperatures, possible preexisting mechanical stress in the plating, and poor quality of tin plating on aluminum.

2.1.2.3.1 Difference in Thermal Expansion of Three Layers

Plating on aluminum (base metal) consists of two types of coating: the lower layer (underplating) is made of copper or bronze and the upper layer is made of tin. If the difference in thermal expansion between the coating material and the substrate is large enough, then thermal shock or temperature elevation can produce mechanical stress for coating different from that for the substrate. Mechanical stress may cause plating delamination and/or produce cracks through the plating. However, the values of thermal expansion coefficients for Sn ($27 \times 10^{-6}/^{\circ}\text{C}$) and Al ($24 \times 10^{-6}/^{\circ}\text{C}$) are quite close, and it is not likely that the thermal expansion coefficient of bronze with Sn as a major component will be significantly different.

2.1.2.3.2 *Mechanical Stress*

It is known that mechanical stress in the plating is higher on the curved and angular sides of a bus bar than on the linear sides. In processing, mechanical stress is absorbed and contained in existing defaults. Heating helps to release this stress, leading to defaults' propagation, creation, and multiplication. Therefore, heating and mechanical stresses are supporting each other in the process of material deterioration. An important observation was made in Ref. [10]: more cracks, voids, and coating peeling are seen on the curved and angular sides than on the linear sides of the aged samples, which may be seen as a proof of the important role of mechanical stress in plating deterioration.

2.1.2.3.3 *Quality of the Plating Procedure*

During multiple steps of the plating process, including surface activation and cleaning, plating interfaces are exposed to several chemicals, some of them with proprietary composition. If any of the activation and rinsing phases during the plating process is not properly performed, then the residues of the chemicals may pollute the plating interfaces. A detailed SEM/EDS study in Ref. [10] revealed small amounts of elements such as potassium (K), sodium (N), and carbon (C) on interfaces. There could also be other light elements included in the composition of nondisclosed chemicals and in the materials used in the bath rubber lining, such as sulfur (S) and fluoride (F). Even chlorine may be found on the surfaces rinsed with chlorinated water. These impurities, if present, do not cause visible damage to the fresh plating. Over time (longer than 1 week), the chemicals' residues on interfaces could produce bubbles of pressurized gases that tear the plating from inside. This process can be accelerated at elevated temperatures. Therefore, it is possible that, when the tin-plated aluminum bus bars have been heated for a period of just 1 week, the plating has been weakened enough to fail the adhesion test. The poor plating quality may be one of the major causes of tin plating failure on Al bus bars exposed to elevated temperatures.

2.1.2.4 **Tin Plating on Aluminum as a Possible Cause of Connection Overheating**

Freshly plated tin on aluminum usually has a good quality and does not show any defects that may lead to failure. Therefore, if aluminum parts in an electrical installation plated with tin could not be overheated, there should be no problems. It is important to evaluate if there is a possibility of tin-plated aluminum parts be exposed to elevated temperature during extended periods of time in service.

If there is a possibility that a conductive part made of tin-plated aluminum may get exposed to elevated temperatures for prolonged periods of time, there is also a possibility that various types of tin plating on aluminum, traditionally used in electrical industry, may deteriorate and eventually fail. The study [10] has shown that after a tin plating is exposed to a temperature of 150°C for just 1 week, adhesion of the plating begins to deteriorate. If thermal exposure is continued, all three traditional types of tin plating displayed poor plating adhesion after the aging test. Aging-related cracks, voids, and separation developed at the plating interfaces although in different concentrations and progression rates depending on the plating technique.

When in service, the electrical current flowing through the connection generates heat, which eventually raises the temperature of the connection. If one part of the connection is made of a tin-plated aluminum bus bar, continuous exposure to elevated temperature causes the tin plating to lose its adhesion and develop pores and cracks along conductive surfaces.

The longer the thermal exposure, the more the defects appearing in the plating. This causes the electrical resistance on the connection to rise, which in turn causes more thermal energy to be generated. The process continues until heat runaway leads to the connections' thermal failure. To continue using tin plating on Al in applications, where electrical aluminum parts may be exposed to elevated temperatures, special attention should be paid to the improvement of the tin plating's thermal stability. The use of nickel underplating may provide such an improvement (see Section 2.3).

2.1.3 TIN PEST

2.1.3.1 Definition of Tin Pest

Tin pest is an autocatalytic, allotropic transformation of the element tin, which causes deterioration of tin objects at low temperatures. At 13.2°C (about 56°F) and below, pure tin transforms from a silvery and ductile allotrope of β -form white tin to brittle, α -form gray tin.

The transformation is slow to initiate due to its high activation energy, but the presence of germanium (or crystal structures of similar form and size) or very low temperatures aids the initiation. There is also a volume increase associated with the phase change. Eventually, it “decomposes” into a powder named “tin pest” [11]. The photograph in Figure 2.4 is likely the most famous modern photograph of tin pest. It shows the phenomenon of “tin pest” quite clearly [12].

The decomposition of tin will catalyze itself. As soon as the tin began decomposing, the process speeds up; the mere presence of tin pest leads to more tin pest. The tin objects at low temperatures will simply disintegrate decomposing tin into powder. Tin pest has also been called *tin disease*, *tin blight*, or *tin leprosy* (*Lèpre d'étain*). It was observed to occur in medieval Europe, where the pipes of pipeorgans in churches were affected in cool climates.

2.1.3.2 Effects of Alloying Elements and the Environment on Tin Pest

Tin pest was thought to be a problem of pure tin, because tin lead alloys do not decompose into tin pest. It was found that several alloying metals retard or eliminate the formation of tin pest [13].

The most effective alloying elements retarding tin pest are bismuth, antimony, and lead. However, while bismuth and antimony will suppress tin pest at concentrations of <1 weight%, five times higher concentration of lead is needed [12]. A “rule of thumb” is that alloying metals that are highly soluble suppress tin pest.

Those elements that are not highly soluble in tin and tend to form IMC with tin are less likely to suppress tin pest. Examples of such metals are copper and silver. There are limited data that suggest that silver has a retarding effect on tin pest formation; however, the effect appears to be moderate at best. Silver suppresses tin pest but at a much reduced level. Hence, many people assume that it has not been

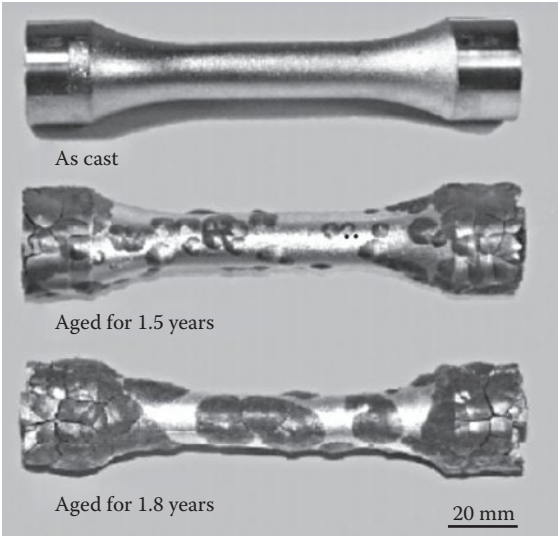


FIGURE 2.4 The formation of β tin into α tin in Sn–0.5Cu at $T < 10^{\circ}\text{C}$. (From Karlya Y., Gagg C., and Plumbridge W.J. *Solder. Surf. Mount Technol.*, 13(1), 39–40, 2000. With permission.)

proven that silver significantly retards the formation of tin pest, especially in the field or use conditions. Copper is considered by most researchers to have a very little effect. Table 2.1 is a summary of the effects of some lead-free alloying elements on tin pest [13].

It is known that high pressure hinders the formation of tin pest and that tensile stress enhances it. These phenomena make sense when one considers that anything that makes it easier to expand the lattice (e.g., tensile stress) should enhance the

TABLE 2.1
Tin Pest Retarding Effects of Lead-Free Alloying Metals

Alloying Metal	Tin Pest Retardant	% Concentration for Effective Inhibition
Bi	Strong	0.3
Sb	Strong	0.5
Pb	Strong	5.0
Cu	None–Weak	>5.0
Ag	Weak–Moderate	>5.0

Source: Lasky R.C. Tin pest: A forgotten issue in lead-free soldering, of *SMTA International Conference Proc.*, Chicago, IL, pp. 838–840, September. 26–30, 2004. Online. Available: <http://www.indium.com/images/blogs/drlasky/files/TinPestPaper0723Final.pdf>. With permission.

formation of tin pest, and anything that compresses the lattice (e.g., compressive stress) will retard tin pest formation. It is also reported that tin oxide formation at the surface will retard tin pest formation. Some unknown additions in soldering such as organic contaminants probably retard tin pest also.

2.1.3.3 Example of Tin Pest Failure in Electrical Connectors

A very interesting case study [14] described a tin pest failure that occurred on plated electrical connectors exposed to low temperatures during storage. Several large, tin-plated copper electrical connectors, used in an electric transit system in northeastern US, were subjected to analysis. The connectors were located on the outside of the transit car and helped conduct the electric supply from overhead cables to the transit car engine circuit. The connectors were ordered with a tin–bismuth coating, containing 2% bismuth. Bismuth is used to combat tin pest (Table 2.1) and it was the reason why the coating was selected.

Some of the coated connectors were put into service while the remainder were boxed up and placed in a storage yard over the winter. The following spring, additional connectors were required to enter the service. On opening the storage box, workers discovered that the once light-gray-colored connectors were now covered with a fine “cigarette ash”-like powder, with regions of the plating clearly separating from the substrate.

Using the SEM technique and a more sensitive spectroscopic method, namely ICPC (inductively coupled plasma spectroscopy), it was found that the gray powder and unaffected areas of the plating contained tin and <0.1% bismuth. With such low levels of bismuth, plating would be susceptible to tin pest if the right conditions are present.

The storage environment for the connectors was assessed and the data revealed that the average monthly temperature from October to May was below 13°C (55°F), and during the winter months December, January, and February it was nearly 0°C (below 30°F). As noted earlier, at temperatures below 13°C (55°F), tin pest propagates. Therefore, the conditions were suitable for tin pest to initiate, and the tin plating was in a susceptible condition (i.e., essentially bismuth-free).

X-ray diffraction (XRD) was used in Ref. [15] to determine if tin pest had developed. Since tin pest is the transformation of tin from a body-centered tetragonal structure (β tin) to a cubic structure (α tin), the use of XRD on the affected areas provided conclusive evidence of the phase constituents present. In the unaffected areas the tin plating appeared to consist of metallic β tin. However, in the affected, powdery areas the tin was present in the α -form—tin pest.

2.1.3.4 Impact of RoHS on Possible Tin Pest Failures

On July 1, 2006, a new directive, the RoHS Directive, took effect [16]. The RoHS Directive restricts the use of six hazardous materials in the manufacture of various types of electronic and electrical equipment. It is closely linked with the WEEE Directive which sets collection, recycling and recovery targets for electrical goods and is part of an initiative to solve the problem of huge amounts of toxic electronic waste.

RoHS is often referred to as the lead-free directive, but also restricts the use of six other substances: lead, mercury, cadmium, hexavalent chromium (CrVI), polybrominated biphenyls (PBB), and polybrominated diphenyl ether (PBDE).

Although RoHS is a step in the right direction toward dealing with toxic electronic waste, it could lead to a greater number of tin pest failures. Tin pest had largely become a problem in the past, which brought to life the wide use of tin alloys to combat it. One of the popular and effective tin alloys is the one with lead, the use of which is restricted by RoHS. Since RoHS bans most uses of lead the problem has returned, as lead-free alloys contain 95–99% tin. With the adoption of the RoHS directive regulations in Europe, and similar regulations elsewhere, traditional lead/tin solders have been replaced by solders containing primarily tin, rendering prevention of tin pest (and related problems such as tin whiskers) a modern technological challenge [14,15]. Tin pest could dangerously affect the safety and functionality of electronic products used across many manufacturing sectors, such as the avionics and electronic industry.

For example, the leads of some electrical and electronic components are plated with pure tin. In cold environments, this can change to α -modification gray tin, which is not electrically conductive, and fall off the leads. After heating backup, it changes back to β -modification white tin, which is electrically conductive, and can cause electrical short circuits and failure of equipment. Such problems can be intermittent as the powdered particles of tin move around.

Tin–lead solders have been used in the electronic industry for decades because of their good conductivity, fluidity, and solderability. The lead is added to the tin solders to improve fluidity, with the unexpected side benefit that it is the most common alloying addition used for combatting tin pest. With the introduction of RoHS, and its restrictions on lead, new lead-free solders had to be developed. Tin pest can be avoided by alloying with small amounts of electropositive metals soluble in tin's solid phase, for example, antimony or bismuth, which prevent the decomposition. Silver, indium, and lead have also been used, but lead is not soluble in tin's solid phase.

The most common replacements are tin–copper, tin–silver, and tin–silver–copper. All three alloys have a similar solderability property as the lead–tin solders they are replacing. However, one property they do not possess is an inherent resistance to tin pest, since they no longer contain the pest-mitigating lead. Testing of these lead-free solders has shown that they can be susceptible to tin pest [17,18].

So these new solder materials may be susceptible to tin pest when exposed to low temperatures. For most consumer electronics there should not be any issue, since they are rarely exposed to temperatures below 13°C (~55°F). The impact that RoHS may have in relation to tin pest failures would be electronic products operating in cold climates, such as telecommunication base stations (cell phone towers), automobiles (vehicles for snow conditions such as Sno-Cats), military (weapons systems), space (satellites), and outdoor recreation electronics.

2.2 USE OF UNDERPLATING FOR PLATING LONGEVITY

2.2.1 MITIGATING ROLE OF UNDERPLATING

In conjunction with various plating types, underplating is often used to enhance the performance of the plating. Without underplating, the prime finish would be

plated directly over base metals, which results in a number of failure mechanisms, such as:

1. Formation of IMC
2. Diffusion of base metal (copper) through plating (gold)
3. Increased wear of the plating
4. Thermal deterioration of the plating (tin on aluminum)
5. Diffusion of zinc through base metal (certain brass alloys)
6. Through pore base metal corrosion

There are three basic underplating types, namely, silver, copper, and nickel, which could be used in contact systems.

Silver was used as underplating in the early 1960s. However, it was found that silver migrated through gold and formed disruptive films on the contact surfaces or at the very best cosmetic discoloration. Silver as an underplate is no longer in use.

Copper underplating is only used in a few applications due to diffusion tendency and tin/copper intermetallic formation. Copper as underplating covers substrate surface defects, which reduces porosity by creating a smoother surface. It does not, however, enhance wear resistance or increase corrosion resistance. The downside of copper underplating is its ability to diffuse through gold and its tendency to form IMC with tin (alloys).

Nickel is the most common and important type of underplating currently used.

2.2.2 ADVANTAGES OF NICKEL AS UNDERPLATING

Tin plating on copper tends to form SnCu IMC, whose electrical properties affect the conductivity of electrical contact and play a detrimental role in longevity and performance of the contacts. For more about the formation of IMC, see Section 2.5. One of the techniques used to minimize or slow down the process of CuSn IMC formation is application of Ni underplating.

Ni underplating provides the following functions for the plating:

- Covers defects in the substrate surface, which reduces porosity
- Acts as an internal diffusion barrier preventing the diffusion of zinc and copper from penetrating through gold
- Serves as an external diffusion barrier preventing pollutants from reacting with base metals; therefore it is increasing corrosion resistance
- Increases wear resistance
- Eliminates Cu/Sn intermetallics
- Improves resistance to thermal deterioration of the plating

2.2.2.1 Ni Underplating Provides a Diffusion Barrier

Ni underplating is used often to plate gold over other metals, such as copper. Copper atoms can diffuse through precious metal plating, and will oxidize once they reach the surface. This diffusion is time and temperature dependent. Higher temperatures

provide a greater number of atoms with the necessary energy to move through the lattice. Therefore, diffusion will occur more readily at higher temperatures.

Ni underplating provides a very effective diffusion barrier, preventing copper from migrating to the surface. It can slow down creep corrosion from bare edges, and can passivate pores in the overlying layers, minimizing pore corrosion. Even if there are no pores in the plating and there are no bare edges, it is still possible for the base metal to corrode.

2.2.2.2 Ni Underplating Prevents the Formation of Intermetallics

When applied under tin plating on copper, nickel underplating helps to prevent copper–tin intermetallic formation in tin and tin–lead-coated contacts [19–21]. This increases the service life if the nickel underplate has low residual tensile stress. Otherwise, the nickel underplate may reduce the fatigue life of the contact.

2.2.2.3 Ni Underplating Improves Wear Resistance

If the electrical contact is going through many mating and unmating cycles, increasing contact wear resistance becomes very important. The wear resistance of a surface depends on the hardness of every layer, not just the outermost layer. Nickel is typically much harder than the base metals and the noble metal contact finishes commonly in use. This means that the use of nickel underplate increases the overall hardness of the contact surfaces and makes the contact interface more durable.

2.2.2.4 Ni Underplating Increases Corrosion Resistance

Application of Ni layer underplating provides an effective means for corrosion protection of base metal from pore and creep corrosion.

2.2.2.4.1 Pore Corrosion

Nickel can significantly reduce the possibility of pore corrosion. Nickel underplating will have fewer pores than the top layer because it is usually applied in a thicker layer than the overlying precious metal. In order for the base metal to be exposed, the pores in every coating layer would have to coincide. It means that the probability of a nickel underplating to be exposed to the atmosphere is very low, and therefore the base metal would not be exposed as well. A protective nickel oxide layer will form in any such pores. Since the oxide does not creep, the pores are effectively passivated, and the noble metal contact surface will remain unblemished.

2.2.2.4.2 Creep Corrosion

The passive oxide formed by nickel will also help to limit the amount of creep corrosion from bare edges. The exposed copper at the bare edges will oxidize, and the corrosion product will tend to spread outward. However, the nickel underplating will oxidize as well. This passive layer of nickel oxide will inhibit the spread of the active copper corrosion product across the underplate. Unfortunately, it will not entirely prevent the eventual creep of corrosion product onto the precious metal, but it will significantly reduce the rate of spreading. This will increase the useful life of the contact. However, for contacts that operate in aggressively corrosive environments, it is always best to eliminate bare edges.

2.2.2.5 Other Advantages of Ni Underplating

Nickel layer between base metal and plating serves to enhance the adhesive and abrasive sliding wear resistance of base metal. Ni underplating improves base metal durability during fretting. It increases the nobility of the contact if the base metal is porous and if sulfur, hydrogen sulfide, and some other pollutants are present.

2.2.3 RECOMMENDED THICKNESS OF NICKEL UNDERPLATING

The thickness of Ni underplating depends on application. Both electroplated Ni and EN are used for plating gold over other metals, such as copper or aluminum. Electroplated Ni is used as underplating for tin plating on copper and aluminum.

The use of ductile nickel underplate for hard gold $<5\text{ }\mu\text{m}$ thick is nearly universal. A typical range of nickel thickness in gold-plated connectors is $1.25\text{--}4.0\text{ }\mu\text{m}$. The lower limit is a sufficient underplating thickness to provide the basic benefits to the nickel underlayer. The upper limit is determined by both cost–benefit and mechanical considerations. The cost–benefit issue is obvious; more nickel means more plating time and material cost. The mechanical considerations are more complicated. On the one hand, as the nickel plating thickness increases, the ductility of the nickel tends to decrease, and reduced ductility can lead to cracking of the plating. On the other hand, the roughness of the thicker plating tends to increase, and the increased roughness may compromise porosity and wear performance.

Nickel underplating is used for plating gold on aluminum for aerospace applications [22]. The process includes an electrolytic copper underplating ($5\text{ }\mu\text{m}$) and then electrolytic nickel deposit ($10\text{ }\mu\text{m}$), and after that electrolytic gold deposit ($5\text{ }\mu\text{m}$). Some OEM specifications for plating tin over aluminum recommend applying an Ni underplating of $5\text{ }\mu\text{m}$. Some suppliers of distribution and transmission voltage power system products and solutions specify the technique of plating of wrought or cast aluminum for hot tinning applications as the Alstan 70 [23] process with $5\text{ }\mu\text{m}$ of nickel under $5\text{ }\mu\text{m}$ of tin.

However, there are some precautions that must be taken when using nickel underplating.

- Ductile nickel should be used. Some nickel baths result in brittle conditions to exist. This has implications for crimp applications and when preplated materials are used.
- Some nickel baths are stress–related, increasing potential residual stresses in contacts.
- The thickness of the underplating must be controlled. It should not be less than $1.25\text{ }\mu\text{m}$ ($50\text{ }\mu\text{in.}$) for porosity reasons. It should not be more than $4\text{ }\mu\text{m}$ ($150\text{ }\mu\text{in.}$) as it can start having an impact on the “composite” modulus of elasticity. This could affect spring rates and other mechanical features such as mating forces.

Additionally, with all the advantages that nickel underplating provides, it is important to take into account that nickel, when used for gold plating, will also eventually diffuse through gold. It may also form nickel–tin intermetallics when used as

underplating for tin (Section 2.3). The diffusion and intermetallic growth rates for nickel are very slow and, under normal application environments, usually pose little or no potential functional problems.

2.3 APPLICATIONS OF Ni UNDERPLATING

2.3.1 USE OF Ni UNDERPLATING FOR TIN PLATING ON COPPER

Application of Ni underplating plays a twofold role when used for tin plating on copper [19–21]. First, it prevents copper–tin intermetallic formation in tin and tin–lead-coated contacts. Another important role of nickel underplating is to slow down the formation of tin whiskers. However, there is a chance that nickel itself may form IMC with tin. More detailed explanation of the formation of IMC will be given in Section 2.5.

2.3.1.1 The Formation of Ni–Sn Intermetallics

The use of Ni underplate for plating Sn over Al is in practice, but studies of the behavior of two interfacing metals (nickel and tin) are conducted generally on the solder joints. It turns out that Ni also forms an intermetallic phase with tin, although the process of Ni–Sn intermetallics formation is different from that of Cu–Sn intermetallics.

It was determined that the formation of IMC between tin-based solder and electroplated Ni substrate is inevitable. However, the thickness of the Ni–Sn IMC layer is approximately only one-quarter as thick as the Cu–Sn IMC formed in the same conditions (Figure 2.5) [24].

The growth of Ni–Sn IMC is linear with the temperature. The Ni–tin IMC layer usually consists of Ni_3Sn_4 brittle phase, since other phases (Ni_3Sn and Ni_3Sn_2) can be formed only on a very rough surface or under temperatures higher than 200°C . The Ni–Sn intermetallic layer is peaky and spiky, and Ni_3Sn_4 whiskers come into solder along the interface, which is another difference to Cu–Sn intermetallics that is usually smooth.

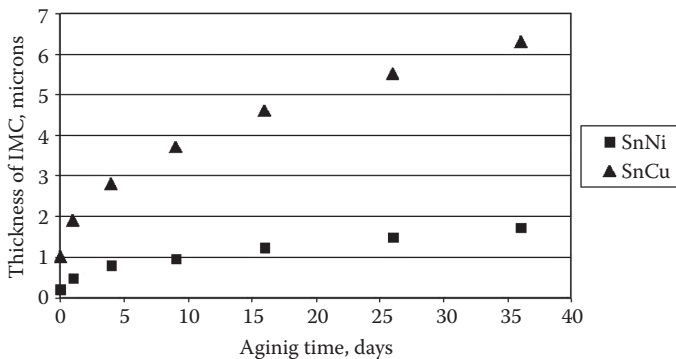


FIGURE 2.5 Thickness of IMC after aging at 120°C for 0–36 days. (Modified from Chan Y.C. et al. Reliability studies of BGA solder joints—effect of Ni–Sn intermetallic compound, *IEEE Transactions on Advanced Packaging*, 24(1), 25–32, February. © 2001, IEEE.)

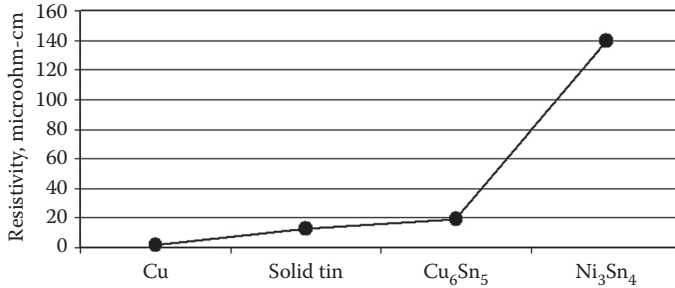


FIGURE 2.6 Electrical resistivity of Cu–Sn and Ni–Sn IMC compared with copper and tin. (Modified from Chan Y.C. et al. Reliability studies of BGA solder joints—effect of Ni–Sn intermetallic compound, *IEEE Transactions on Advanced Packaging*, 24(1), 25–32, February. © 2001, IEEE)

It was shown in Ref. [25] that brittle Ni_3Sn_4 IMC contributes mainly to the fatigue failure of the solder joint and also is the root cause of fracturing near the IMC layer. Another difference between two types of IMCs is that the volumetric shrinkage of Ni_3Sn_4 layer is more, about 10.7% during the transformation from solid phases of Sn and Ni to the Ni_3Sn_4 compound, compared with volumetric shrinkages to form Cu_6Sn_5 and Cu_3Sn , which are only 5% and 8.5% respectively.

As the thickness of IMC layer increases, internal strain and intercrystalline defects are formed and increase gradually in severity at the grain boundary of the Ni_3Sn_4 IMC and IMC/solder interface. They play a significant role in mechanical fatigue, when strain accumulation around IMC results in cracks initiating and propagating. Therefore, the thicker the layer the shorter the fatigue lifetime of the solder joint under mechanical stresses.

In Ref. [25] the formation of Cu–Sn and Ni–Sn intermetallics has been studied in Sn–Pb plating. The data on resistivity of IMCs compared with that of tin and copper given in Ref. [25] are used in Figure 2.6 to show how significant is the growth of resistance in intermetallics, particularly in Ni–Sn IMC. Hardness is also high in IMCs (~420 BHN). It was also shown [25] that the total growth of Cu–Sn IMC is almost twice faster than the growth of Ni–Sn IMCs (Table 2.2).

Intermetallics tend to grow faster in bright tin plating compared with matte tin–lead plating. Slightly different data on the thickness of the IMC are given in Ref. [24], but they still show that Ni–Sn IMC layer is much thinner than that of Cu–Sn growing in the same conditions. It is interesting to compare the thickness of Ni–Sn IMC growing at different temperatures. Since Cu–Sn intermetallics tends to grow faster than Ni–Sn IMC, it allows to suggest that usage of nickel barrier plating may retard the growth of the intermetallics [26].

2.3.2 NICKEL UNDERPLATING AS A TIN WHISKER MITIGATION TECHNIQUE

Using a nickel or silver underplate has been proven to be excellent in preventing the formation of Cu_6Sn_5 intermetallics. It has been suggested that the formation of intermetallics in the base metal below the pure tin plating creates stresses that promote

TABLE 2.2
Growth of SnCu and SnNi Intermetallics in SnPb Plating at 150°C

Tin Plating Type	Aging Time (weeks)	Cu ₆ Sn ₅ (μm)	Cu ₃ Sn (μm)	Cu–Sn Total (μm)	Ni ₃ Sn ₄ (μm)
Matte	1	1.95	1.3	3.25	1.46
Bright	1	3.9	1.79	5.69	2.11
Matte	4	2.2	2.0	4.2	2.28
Bright	4	3.74	2.93	6.67	3.41

Source: Modified from Chan Y.C. et al. Reliability studies of BGA solder joints—Effect of Ni–Sn intermetallic compound, *IEEE Transactions on Advanced Packaging*, 24(1), 25–32, February. © 2001, .

the growth of tin whiskers. Based on this assumption, in the development of several tin whisker mitigation strategies [27], it has been suggested that using barrier layer such as nickel between the base metal and the pure tin finish can reduce the likelihood of tin whisker growth. The results of studies on the effect of nickel underplating on tin whiskers growth are controversial.

To provide a quantitative relationship between the size of the whiskers and various factors, the concept called whisker index (WI) was introduced in Ref. [28]. WI is defined as a function of the number, length, and diameter of the whiskers. The effect of applying Ni underplating was studied in Ref. [28] by comparing the WI for satin bright tin, satin bright tin after reflow and satin bright tin over a nickel underlayer. It was determined that both reflow and nickel underlayer further reduce the propensity of whisker formation. A nickel barrier layer of 1.5 μm over a copper base material significantly reduced the growth of tin whiskers on a low stress tin finish.

By utilizing a nickel underlayer with the satin bright tin finish effectively eliminates whisker formation. WI as a function of time measured in months decreased from 10 for satin bright tin to 3 for reflowed satin bright tin, and no whiskers have been found in satin bright tin with a nickel barrier layer after 6 months of aging. After 10 months of aging, the difference between WI in two satin bright tin platings without Ni underplating became smaller (9.5 and 8), but there are still no whiskers found in the plating with a Ni barrier layer.

In Ref. [29], lead frame samples have been tested for over 3400 h in different temperature and RH conditions: (a) 105°C and 100% RH and (b) 50°C and 25% RH. Both lead frames were on bronze substrates and had 1–2 μm underplating (silver or nickel) with 5–7 μm tin on the top. Results have shown hillock and whisker growth differences in the samples depending on the environmental conditions, which is attributed to the different stress-causing mechanisms. Growth differences have also been found in the different underplating materials.

On the other hand, the data presented in Ref. [30] indicate that tin whiskers can still grow on the parts with nickel underplating. However, in this study a nickel undercoat was applied over silver, which was in turn applied over a ceramic material.

In another extensive study [31] the conclusion was that a nickel underlayer is not effective in preventing tin whisker growth.

In the latest survey available on different mitigation techniques [32], application of Ni underplate fell under the category of “weak mitigators,” while the silver underplate is in the category of “very weak or nonmitigators,” which means that the use of nickel underplating on copper substrates is considered to reduce tin whiskers’ growth. For the manufacturer, it is important to have part suppliers providing Ni underplating of the desired quality.

However, the base material has been shown to contribute to whisker growth despite the application of a barrier layer. For example, analysis of the data in Ref. [31] indicated that both whisker density and lengths are related to tin thickness. The effectiveness of the underplating appears to depend on the base material as well as the process parameters used to deposit the pure tin finish. At present, it is not clear whether the underplating could permanently stop whisker formation. However, nickel is reported to be the underplating of choice when using a pure tin finish.

2.3.3 Ni UNDERPLATING FOR TIN PLATING ON ALUMINUM

In Section 2.1 it was shown that in applications, where electrical aluminum parts may be exposed to elevated temperatures, using tin plating on Al may lead to severe deterioration of the plating, resulting in a significant increase of electrical resistance. The energized parts with increased resistance generate extra heat, which eventually causes thermal failure.

Because tin-plated aluminum conductive parts and connections remain in wide use in the electrical industry, it is necessary to further improve the thermal performance of tin plating. The role of Ni underplating in improving the ability of tin plating on aluminum to perform well at elevated temperatures has been studied in Ref. [33].

2.3.3.1 Plating, Sample Preparation, and Testing Techniques

The properties of tin plating on Al with Ni underplating have been studied for the specific technique of the plating process currently used in the electrical industry, based on OEM specifications for indoor electrical application (bolted connection) tolerating water condensation.

2.3.3.1.1 Plating Process

Aluminum connection bars have been tin plated using nickel underplating. The thickness of bright tin plating was a minimum of 12 μm . Since tin exhibits good corrosion resistance just as Ni does, 5–6 μm of Ni is usually enough to protect the Al bus bar. The thickness of the applied Ni underplating was a minimum of 5 μm , with a maximum thickness of 10 μm to limit CR. In addition, the tin plating process consisted of the following sequence with each step of the process completed with rinsing: degreasing (alkaline etching); deoxidation (acid etching); double activation (zincate); electrolytic nickel plating; and electrolytic tin plating.

2.3.3.1.2 Samples

Ten plated aluminum parts (alloy EN AW-6082) have been randomly taken from one batch of the automatic production line after having passed production tests including visual inspection and fluorescence $\times$ thickness measurement. Each of the selected six parts was cut into three parts, two parts for the adhesion test and one for thickness measurement (before and after the accelerated aging test).

2.3.3.1.3 Testing Techniques

To determine thermal properties of tin plating with Ni underplating, the accelerated aging test and the adhesion test have been used in the same sequence as was done in Ref. [10] and described in Section 2.1.

2.3.3.2 Quality of the Plating and Interfaces

SEM/EDS metallographic analysis was performed in Ref. [32] to determine

- Thickness of tin plating and preplating Ni layer
- Presence of pores, voids, and gaps along each interface (Al–Ni, Ni–Sn)
- Morphology of tin plating across the layer
- Chemical composition of plating and preplating layers
- Formation of intermetallics at the Ni–Sn interface

Average thicknesses measured on freshly plated samples was 15 μm for tin plating and 6 μm for nickel underplating [33] according to OEM tin coating specifications.

Nonaged samples demonstrated very good adhesion: tin plating and nickel underlayer are applied onto each other with a perfect fit. There are no voids, pores, or cracks along all interfaces (Al–Ni and Ni–Sn) (Figure 2.7). In addition, all nonaged

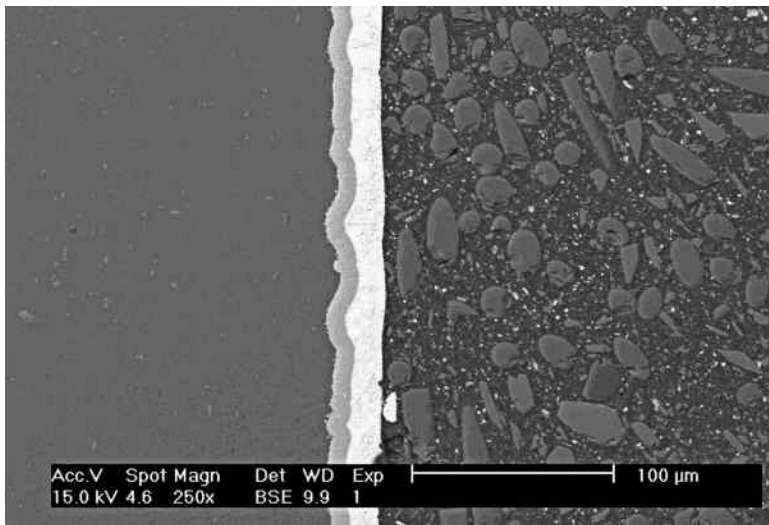


FIGURE 2.7 Microphotograph of aluminum (at the left side of the picture) with Ni underplating layer and tin plating.

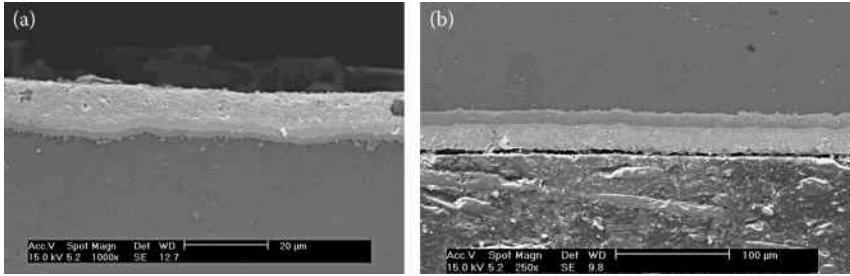


FIGURE 2.8 Microphotograph of Sn plating on Al with Ni underplating: (a) after 3 weeks of thermal aging; (b) after 4 weeks of thermal aging.

samples passed the adhesion test: the original coating can be considered to be properly adhesive, and its quality is good.

Samples aged up to 8 weeks at 150°C still exhibited a strong adhesion. The quality of the adhesion of the aged samples was confirmed by the absence of any peeling during the tape adhesion test. According to SEM analysis, there is no evidence of any cracks or separation at the two plating interfaces (Al–Ni and Ni–Sn) (Figure 2.8).

2.3.3.3 Formation of Ni–Sn Intermetallics

SEM metallography revealed the formation of an additional layer at the Ni–Sn interface, and x-ray chemical analysis confirmed that this layer is a Ni–Sn IMC. Ni–Sn IMC layer is also present in nonaged (as-received) samples as well, but to a lesser degree. Actually, the IMC layer of freshly plated samples is discontinuous, and its maximum thickness is about 1 μm.

After 1 week of aging, a continuous layer appears at the interface of the tin plating and the Ni underlayer. The thickness of the IMC layer increases with increasing high temperature exposure. It is found that after 3 weeks of aging the IMC layer stops growing: the thickness of Ni–Sn IMC did not change during the following weeks of thermal exposure [33]. IMC thickness stabilization has already been observed in some studies, and is considered as the result of a diffusion-controlled growth for thick layer [34].

The maximum thickness of the intermetallic layer ranges between 3 and 4 μm, which is comparable with IMC thicknesses measured after about 4-week aging at 120–150°C [22,24]. In addition, no evidence was found that the IMC growth induces a reduction in the thickness of the Ni underplating.

Formation of Al–Ni IMC is also possible on another interface—between Ni layer and the base metal Al. Aluminum–nickel IMC was found in Al to Ni-plated Cu connectors [35], as well as in electronic materials annealed at high temperatures (400°C)—both Ni_2Al_3 and NiAl_3 IMCs [36]. However, after 8 weeks of aging, no traces of Al–Ni IMC on the Al–Ni interface could be found [10].

2.3.3.4 Comparison of Aging Behavior of Sn Plating with Ni, Bronze, or Cu Underlayer

A study of the quality of tin plating on aluminum using either bronze or copper as the underplating revealed poor adhesion characteristics after 2 or 3 weeks of exposure

at 150°C [10]. The purpose of the study in Ref. [33] was to determine whether nickel underplating might improve the thermal performance of tin plating on aluminum. It was found that Ni underplating outperforms bronze or copper used as underplating in traditional tin plating techniques (Table 2.3). All layers (including Ni–Sn IMC layer) show a very good adhesion after 8-week aging.

The influence of the Ni–Sn formation on the CR (especially for bolted connection) is expected to be quite weak. Although the resistivity of Ni–Sn IMC is about 3–4 times higher than that of nickel [37], a significant increase in CR is more likely to come from plating defects, including cracks and delamination, than from a change in material resistivity, as was suggested in the investigation on tin plating with either bronze or copper underplating [10]. Besides, the results of Refs. [10] and [34] demonstrate that the accelerated aging test is a very good way of discriminating different plating techniques.

TABLE 2.3
Results of the SEM Study and the Adhesion Test of Aged Samples Using Bronze, Cu, and Ni as Underplating

Plating Facts			Period of Thermal Aging (weeks)			
Type of Tin Plating and Underplating	Average tin Plating Thickness (μm)	Underplating Thickness (μm)	2	3	4	8
Alstan 80/88, Bronze	11	1.5	Some voids and gaps, adhesion test passed	Multiple pores and gaps along interfaces, adhesion test failed	Multiple voids and gaps along interfaces, coating peeling, adhesion test failed	Failed
Bondal, Cu	5	1	No voids or gaps, adhesion test passed	Some voids and gaps along interfaces, adhesion test passed	Multiple voids and gaps along interfaces, coating peeling, adhesion test failed	Failed
OEM specs, Ni	15	6	No voids or gaps, adhesion test passed	No voids or gaps, adhesion test passed	No voids or gaps, adhesion test passed	No voids or gaps, adhesion test passed
Ni–Sn IMC thickness (μm)			2–2.5	3–4	3–4	3–4

Source: Modified from Chudnovsky B. et al., *Proc. of 24th International Conference on Electrical Contacts (ICEC)*, Saint-Malo, France, pp. 495–500, 2008.

Formation of Ni–Sn IMC is observed in nonaged samples as a discontinuous layer, although the thickness of the IMC is growing with time. However, after 3 weeks at 150°C, the IMC thickness is roughly 3–4 μm and it no longer increases during the next 5 weeks. It appears that the formation of Ni–Sn IMC does not reduce the thickness of the Ni underplating. Stabilization of the IMC thickness was observed in other studies, but is not yet fully understood.

As the data in Table 2.3 show, tin plating on aluminum with Ni as underplating provides an excellent quality of the plating in terms of adhesion and stability even after 8-week thermal aging at 150°C. For this temperature, the thicknesses of tin plating and Ni underplating are high enough to prevent depletion that might induce significant degradation of the plating structure. This is a great improvement in plating quality compared to traditional tin plating techniques on aluminum using either bronze or copper as underplating.

2.3.4 Ni UNDERPLATING FOR GOLD PLATING

Gold is a noble metal; hence it is very stable; it does not chemically interact with any chemical compound normally found in a connector environment to form an electrically insulating film. Gold is also a good thermal conductor as it is an excellent electrical conductor. For these reasons gold is recommended for use as contact plating in high reliability applications, particularly when the contacts are operating in corrosive environments. Another good quality of gold is that it is not susceptible to fretting degradation and gold contact performance can be enhanced with lubrication.

The protection offered by gold can be compromised if there are pores or cracks in the coating, through which atmospheric pollutants can attack the substrate metal to form insulating corrosion products. A limited amount of porosity can be tolerated depending upon the severity of the contact's service environment.

Because gold is a noble metal and because thin gold plating tends to be porous, gold coatings are susceptible to the creep of base metal corrosion products across the surface of the gold after formation at pore sites and edge boundaries. Corrosion creep can be inhibited by applying a nickel underplating prior to application of the gold. The nickel underlayer serves as a diffusion barrier to most base metal constituents, and nickel corrosion products are self-limiting, passive and not susceptible to corrosion creep. A nickel underlayer can act as an inhibitor of the pore and creep corrosion, and a diffusion barrier for gold [38,39].

An illustration of how Ni underplating works against pore and creep corrosion for gold plating is shown in Figure 2.9 [38].

Pore-Corrosion Inhibitor—Nickel underplating forms passive oxides at the base of pores. The underplating serves as a pore corrosion inhibitor provided that the environment does not contain significant amounts of acidic pollutants, such as chlorine.

Corrosion Creep Inhibitor—Nickel acts as a barrier to corrosion product migration.

Diffusion Barrier—Nickel underplating slows down the diffusion of base metal constituents of the contact spring (such as copper and zinc) to the gold surface, where they could oxidize and form an insulating film of corrosion product.

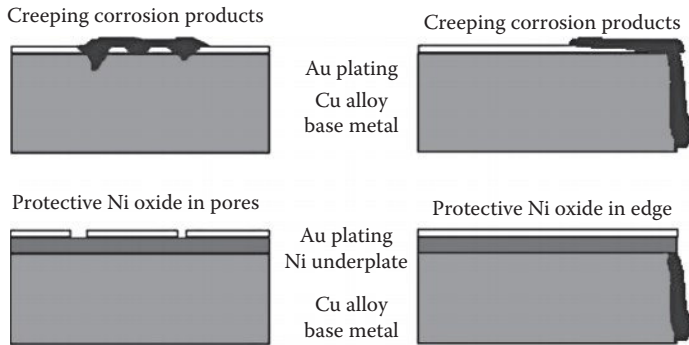


FIGURE 2.9 Passivation of pores and bare edges by the use of a nickel underplating for gold plating. (From Gedeon M. Nickel as an undercoating, *Brushwellman Technical Tidbits*, 4(6), June 2002, Online. Available: <http://materion.com/Search/Search.aspx?Search=nickel+as+a+n+undercoating&l=Site&C=False>. With permission.)

Mechanically Supporting Underlayer for Contacting Surfaces—A relatively hard nickel underplating serves as a mechanical support for the gold coating, and increase its durability.

The nickel underplating must be continuous and have sufficient thickness to perform the particular function for which it is intended. As a general rule, a minimum thickness of 1.25 μm (50 $\mu\text{in.}$) of nickel should be used for plating under gold.

2.4 GALVANIC CORROSION: CONNECTIONS MADE OF DISSIMILAR METALS

2.4.1 HAZARD: GALVANIC CORROSION

The corrosion characteristics of a metallic material are very important in electrical design. A number of different mechanisms cause corrosion, such as when the metal enters a chemical reaction with other elements such as oxygen, chlorine, or sulfur. One of the most common mechanisms of corrosion, namely *electrochemical* or *galvanic corrosion*, can develop when two *dissimilar metals* are electrically connected and exposed to an *electrolyte*.

An electrolyte is an electrical conducting solution in which positively charged and negatively charged ions can move freely. Acids, alkalis, and salt solutions, such as sea water, make good electrolytes. The electrolyte may be present in bulk as when immersed in sea water or as a thin condensed film of water on the metal surface. In moist industrial areas harmful electrolytes are formed by the absorption of gases by rain and fog to form acids and salts, while in seaside areas they are formed by the combination of salt with the moisture to form saline solutions.

Electrical interconnect components are subject to galvanic corrosion due to the incompatible coupling of plating materials and base metals. Examples of galvanic corrosion when two dissimilar metals connected together are shown in [Figure 2.10](#).

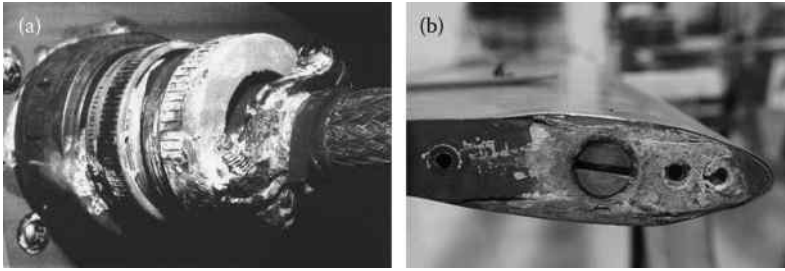


FIGURE 2.10 Galvanic corrosion of dissimilar metals. ((a) From <http://www.interconnectionworld.com/index/display/article-display/194291/articles/connector-specifier/volume-19/issue-12/features/electrical-connections-what-you-can-do-to-prevent-corrosion.html>. With permission. (b) From <http://corrosion.ksc.nasa.gov/images/gal3.jpg>, courtesy of NASA.)

2.4.2 DEFINITION OF DISSIMILAR METALS

Each metal is characterized by its electrical potential. The varying potential indexes of some metals and alloys in the electrolyte are shown in the *galvanic series* in Table 2.4. Those metals which are on the top of the table with small values of electrical potential are considered as noble or *cathodic*, and the metals and alloys in the lower part of the table are less noble or *anodic* than the metals above them. The *anodic* metal will corrode and the *cathodic* metal (more noble) is protected from corrosion.

Whenever dissimilar metals are in the presence of an electrolyte, a difference in electrical potential is developed. One metal becomes the cathode and receives a positive charge. The other becomes the anode and receives a negative charge.

In the presence of an electrolyte a galvanic cell is thus set up where one of the metals will act as an anode and the other will act as a cathode according to the electrical potential of each metal. When these metals are in contact, an electrical current will flow, as in the case of any short circuited electric cell. This electrolytic action causes an attack on the anodic metal, leaving the cathodic metal unharmed.

Generally, the closer one metal is to another in the series, the more compatible they will be; that is, the galvanic effects will be minimal. On the other hand, the farther one metal is from another, the greater the corrosion will be.

The extent of the attack is proportional to the strength of the electrolytic current, which in turn is proportional to the electrical potential difference developed. The magnitude of the potential difference generated between two dissimilar metals can be seen from the position of these metals in the galvanic series. When two metals are in contact in an electrolyte, the one higher up in this series is the anode, the corroded metal, whereas the one lower is the cathode, the protected metal.

The further apart the metals are in this series, the greater the electrolytic potential difference and the greater the attack on the anodic metal. General rankings of the galvanic corrosion susceptibility of different contacting material combinations show that silver-to-gold and silver-to-tin are satisfactory combinations in many environments; with silver-to-tin presenting the most risk in harsher environments.

TABLE 2.4
Electrical Potential Index (V) for Metals and Alloys

Metals, Alloys	Index (V)
<i>Cathodic or Noble End</i>	
Gold, solid and plated, Gold–platinum alloy	0.00
Silver, solid or plated	0.15
High nickel–copper alloys	0.15
Nickel, solid or plated, Monel	0.30
Copper, solid or plated; low brasses or bronzes; copper–nickel alloys; nickel–chromium alloys	0.35
Brass and bronzes	0.40
High brasses and bronzes	0.45
18% chromium-type corrosion-resistant steels	0.50
Chromium plated; tin plated; 12% chromium-type corrosion-resistant steels	0.60
Tin-plate; tin–lead solder	0.65
Lead, solid or plated; high lead alloys	0.70
Aluminum, wrought alloys of the 2000 Series	0.75
Iron, wrought, gray or malleable, plain carbon and low alloy steels	0.85
Aluminum, wrought alloys other than 2000 Series aluminum, cast alloys of the silicon type	0.90
Aluminum, cast alloys other than silicon type, cadmium, plated and chromate	0.95
Hot-dip-zinc plate; galvanized steel	1.20
Zinc, wrought; zinc-base die-casting alloys; zinc plated	1.25
<i>Anodic or Active End</i>	

Source: Adapted from Army Missile Command Report RS-TR-67–11, *Practical Galvanic Series*.

Galvanic series relationships are useful as a guide for selecting metals to be joined. It will help to select metals as close as possible to each other in galvanic series. These metals which will have a minimal tendency to corrode if connected. The positions of the coupled metals in galvanic series will also indicate the need or degree of protection to be applied to lessen the expected galvanic interaction (Military Standard 889B (Notice 3), “Dissimilar Metals,” May 1993).

2.4.3 GALVANIC CORROSION OF COPPER-TO-ALUMINUM CONNECTIONS

The two types of corrosion that exhibit the greatest influence on the electrical properties of a metal are oxidation/atmospheric corrosion and galvanic corrosion. Both copper and aluminum have a high resistance to oxidation because of the manner in which their surfaces oxidize. In the case of these two metals a thin oxide film is formed on their surfaces. This film becomes a protective coating, which offers resistance to any further oxidation. In corrosive atmospheres copper is usually protected by corrosion-resistive plating such as silver or tin.

Since most of the commonly used electrical conductors are resistant or protected from oxidation, galvanic corrosion becomes very important when bare copper conductor is connected to bare aluminum conductor. Copper and aluminum are quite far

apart in the series (Table 2.4), copper being *cathodic* and aluminum being *anodic*. Hence, when aluminum and copper are in contact in an electrolyte, the aluminum can be expected to be severely attacked.

Aluminum will, in contact with copper and in the presence of an electrolyte, corrode progressively and the process will continue as long as the electrolyte is present or until all the aluminum has been consumed, even though the build-up of corrosion products may limit the rate of corrosion at the surface. The performance of aluminum-to-copper connection is affected by corrosion in two ways. Because of corrosion, the contact area is drastically reduced, causing an electrical failure. Severely corroded connector may cause a mechanical failure as well. In most cases, failure is due to a combination of both effects.

Several conditions must be observed in selecting the most appropriate connection, where it consists of a junction between aluminum and copper conductors. Since aluminum has a high electrical potential compared with that of copper, it will corrode progressively in contact with copper and in the presence of an electrolyte until contact between the two metals is destroyed. It is an undesirable practice to employ a copper connector for use with aluminum because of the possibility of galvanic corrosion.

It is worth noting that there is another issue with copper-to-aluminum connections in addition to possible galvanic corrosion. The use of a copper-to-aluminum connector could result in a resistance increase and premature joint deterioration, and the reason for the insufficient performance of such a connector is that there is a difference in thermal expansion between these two metals.

Aluminum has a higher coefficient of thermal expansion than copper, and for a given temperature rise (TR), aluminum will expand more than an equal size copper member. Therefore, as the temperature rises, both copper and aluminum expand, but to a different degree.

Copper, not being able to expand as much as aluminum, restricts aluminum and causes it to flow. Upon cooling, a dimensional difference begins to create a greater electrical resistance and higher TR. As the repeated cycles continue, resistance and temperature become progressively greater until ultimate failure occurs.

In general, the use of a copper-to-aluminum connector could result in a resistance increase and early joint deterioration: (1) due to the presence of electrolytic fluids in the environment and (2) due to variations in the connection temperature. Therefore, a bare copper-to-aluminum connection may be used only if there is absolutely no other option available.

2.4.4 PROTECTION OF COPPER-TO-ALUMINUM CONNECTIONS FROM GALVANIC CORROSION

There could be situations when the use of copper-to-aluminum connections is unavoidable. In those cases the contact area should be coated with either protective plating or a protective compound/lubricant. Either option will slow down galvanic corrosion, which otherwise will cause a connection failure.

The most important factor for galvanic corrosion to exist is humidity. In order to limit the detrimental effect of galvanic action in corrosive environments and maintain a low CR, various palliative measures may be recommended, such as plating

of Cu and Al buses to suppress the galvanic corrosion of the aluminum-to-copper joint and utilization of proper metallic fasteners. Application of contact aid-compounds prevents ingress of oxygen and humidity inside the contact interface [40].

2.4.4.1 Plated Aluminum Connections

To minimize galvanic corrosion of aluminum-to-copper connectors, a protective coating at the contacting interface must be introduced. Plating has been used as a means of making an aluminum connector suitable for a copper conductor. The plating of aluminum is much more critical than the plating of a more noble metal such as copper.

To be effective in reducing galvanic corrosion between the copper conductor and the aluminum connector, the plated metal must be closer in the electrolytic series to copper than aluminum is. Therefore, it must be cathodic to aluminum. Since porosity and minor scratches are always present, galvanic action can be expected in the presence of moisture, resulting in an attack on the aluminum under the plating. Corrosion tests reveal an attack in the form of a mottled appearance and flaking of the plating.

In addition, the presence of plated metal can cause a galvanic attack of the aluminum conductor, thus reducing the protection offered to this conductor in an aluminum connector. The question of what is the most effective coating for protection of aluminum from galvanic corrosion is still being discussed and studied, but many recommend performing tin plating of a uniform thickness over the entire surface of the contact. Tin serves as a suitable intermediate metal between copper and aluminum. Copper and zinc platings have also been in use.

2.4.4.2 Fasteners

A plated copper bar or a plated copper terminal fitting may be connected to a plated aluminum bar. Metallic fasteners shall be chosen to minimize dissimilar metal corrosion. When it is not possible to avoid joining dissimilar metals, the metal of the fastener shall be from a higher potential group than the structure [41,42]. The connection should be made with a plated steel bolt in conjunction with plated Belleville spring washers and wide series plated steel washers [43,44].

2.4.4.3 Corrosion Protective Compound for Copper-to-Aluminum Connections

Some products, such as petrolatum-type compound containing zinc dust, effectively protect contacts made of dissimilar metals from galvanic corrosion. However, some lubricants may induce galvanic corrosion; therefore, the products for this application should be chosen very carefully. For example, the use of graphite, which has a high noble potential, is not recommended for copper-to-aluminum connections, because it may cause severe galvanic corrosion of copper alloys in a saline environment [45].

A detailed study was performed in Ref. [46] to evaluate the protective properties of various compounds available commercially and recommended for electrical connections. Some compounds provide a good corrosion protection for copper-to-aluminum connections in a wide working temperature range from -25 to $+130^{\circ}\text{C}$.

When aluminum connectors or conductors are involved, proper cleaning of the aluminum as well as the use of a good connector lubricant or compound are essential for trouble-free service. Hard and nonconductive aluminum oxide, developing on the

surface of bare aluminum conductors exposed to air, must be removed from the Al surface prior to making a connection. In all cases, the aluminum conductor should be cleaned by means such as scratch brushing and immediately coated with the connector compound [40].

A generous amount of joint compound should be applied to all joint surfaces before assembly to seal out air and improve corrosion resistance. A bead of compound should appear all around the edges of the joint when the connection is tightened. Excess sealant squeezed out of the joint may be left as is or removed [43].

2.4.5 GALVANIC CORROSION IN STEEL CONNECTIONS WITH ALUMINUM AND OTHER METALS

The connection between metallic parts made of aluminum and steel alloys is possible in electrical installations. A chart that shows electrical potentials for different aluminum and steel alloys can be found in Ref. [47]. Stainless steel alloys can significantly change their potential and become much more active if exposed to stagnant or poorly aerated water. The result of these stagnant conditions is oxygen depletion and the low noble potential, which can make the stainless steel susceptible to corrosion in conditions which might otherwise be considered noncorrosive.

To initiate galvanic corrosion, the two alloys of steel or aluminum and steel must be in electrical contact with each other. The two metals can be bolted, welded, or clamped together, or they can even be just resting against each other. The metal junction must be bridged by an electrolyte, and almost any fluid falls under this category, except for distilled water. Even rain water is likely to become sufficiently conducting after contact with common environmental contaminants.

If the conductivity of the liquid is high (a common example is sea water) the galvanic corrosion of the less noble metal will be spread over a larger area; in low-conductivity liquids the corrosion will be localized to the part of the less noble metal near the junction. An example of such a connection exposed to galvanic corrosion is shown in Figure 2.11.

In this example, a stainless steel bolt is connected to an aluminum plate (Figure 2.11). If it collects water in the corner at the edge of the bolt but the remainder of the plate remains dry, the effective area of the less noble aluminum is only

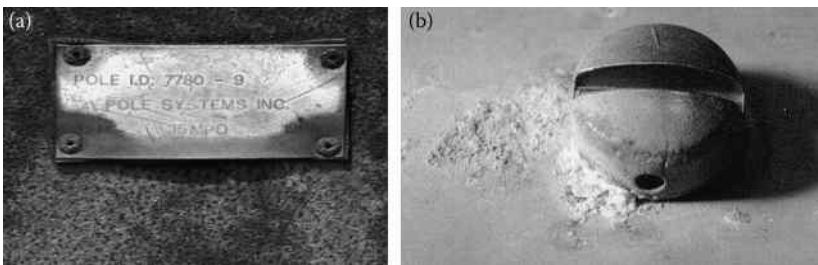


FIGURE 2.11 Galvanic corrosion in connection between stainless steel bolt and aluminum. (From <http://corrosion.ksc.nasa.gov/galcorr.htm>, courtesy of NASA.)

the wetted region; it is quite possible for the aluminum plate to be attacked by galvanic corrosion in the region immediately surrounding the bolt.

To prevent galvanic corrosion in aluminum-to-steel connections [48] one should be particularly aware of zinc-plated or galvanized fasteners in stainless steel sheets—a common substitution because of apparent cost saving or better availability. These less noble fasteners are likely to be rapidly attacked by galvanic corrosion. It is often practical to prevent electrical contact between the dissimilar metals. This may be achieved by the use of nonconducting (e.g., rubber or plastic) spacers, spool pieces or gaskets, perhaps in conjunction with sleeves around bolts.

2.4.6 GENERAL PRECAUTIONS TO MINIMIZE GALVANIC CORROSION IN CONNECTIONS

The following precautions and joining methods are recommended for galvanic corrosion mitigation, whenever it becomes necessary to assemble relatively incompatible metals.

Recommendations for electrical connections:

- The metal couples design should provide that the area of the cathodic member of the connection is considerably smaller than the area of the anodic member. For example, bolts or screws of stainless steel should be used for fastening aluminum sheet, but not vice versa.
- A compatible metallic gasket or washer should be inserted between the dissimilar metals prior to fastening.
- The cathodic member should be plated with a metal compatible with the metal of the anodic member.
- A proper electrically conductive sealant should be selected for the connection.

Recommendations for nonelectrical connections: A nonabsorbing, inert gasket material or washer should be inserted between the dissimilar materials prior to connecting them.

Other precautions:

- Seal all edges of a pair of surfaces made of metals far from each other in galvanic series that are in contact, or in close proximity, and are to be connected, to prevent the entrance of liquids.
- Apply corrosion-inhibiting pastes or compounds under heads of screws or bolts inserted into dissimilar metal surfaces whether or not the fasteners had previously been plated or otherwise treated.
- In some instances, it may be sufficient to apply an organic coating to the faying surfaces prior to assembly. This would be applicable to joints which are not required to be electrically conductive.
- In the cases where it is practical or will not interfere with the proposed use of the assembly, the external joint should be coated externally with an effective paint.

2.5 OTHER DETRIMENTAL PROCESSES AFFECTING PLATING PERFORMANCE

2.5.1 INTERMETALLIC COMPOUNDS

IMC, by definition, is a combination of solid phases containing two or more metallic elements, with optionally one or more nonmetallic elements, whose crystal structure and properties differ from that of the other constituents.

The growth of IMC is often found in those parts having a metallic layer plated over a base metal. The formation of IMC may significantly affect the electrical properties and reliability of electrical connections, mostly in electronic devices [49], particularly when it is found in the solder joints. However, in some cases the resistance of plated electrical parts in electrical equipment may also be increased due to the formation of IMC. Many dissimilar metals in close contact will diffuse and form IMC. An IMC consists of two or more elements, always with the same precise ratio of atoms.

2.5.1.1 Copper–Tin Intermetallic Compounds

Every tin-plated copper alloy experiences the formation of two types of copper–tin IMC— Cu_6Sn_5 and Cu_3Sn —at the interface of the tin and the base metal. For these two copper–tin IMCs, the ratios between Sn and Cu atoms are 6:5 and 3:1, correspondingly.

The compound initially forms at the interface between the plating and the base metal and grows until eventually all the tin is consumed. The rate at which intermetallic Cu–Sn compounds are growing depends on time and temperature. Copper–tin IMC are hard and brittle; at the surface they are easily oxidized. The oxidized IMC can adversely affect CR and solderability.

Because the different types of tin plating are produced in different ways, with different thickness, their IMC reach the metal surface at different times [45]. Several studies have shown that, during the manufacturing process, commercial *hot-dipped tin* quickly forms an intermetallic layer with the thickness of 0.5–1 μm (20–40 $\mu\text{in.}$). Pockets or layers of intermetallic have been found on rather “fresh” commercial *hot-dipped tin*. A stringent connector performance requires thicker coatings.

With *air leveled tin* in which the tin is applied from a molten bath, there is an immediate intermetallic layer at the tin interface of about the same thickness as commercial *hot-dipped tin*. But the air jets allow a thicker tin layer to be produced; the *air leveled tin* surface has an abundance of residual (“pure”) tin just after it is produced.

Because electroplated tin is not produced with hot molten tin, little or no intermetallic is formed at the copper–tin interface during the plating process. The structure of *electroplated tin* exhibits a finer grain size and tends to be more porous than the essentially “cast” structure of the “molten method” products. This affects the growth rate of the intermetallic. *Reflow tin* starts as electroplated tin so there is essentially no intermetallic at this step. But the furnace treatment to melt the tin initiates a thin layer of intermetallic about the same thickness as that initially generated by the molten tin processes.

2.5.1.2 Effects of Temperature and Time on the Formation of Cu–Sn IMC

Copper–tin IMCs form at the interface of the tin plate and the base metal, for all the different processes used for the tin-coated copper alloy strip. With increasing time and temperature, the intermetallic grows to the surface, becomes oxidized, and can affect contact integrity [50]. A schematic illustration of the process [51] is shown in Figure 2.12.

Because commercial *hot-dipped tin* already has some IMC at the surface when produced, its service life is likely to be the shortest. After 3 months in storage at summer temperatures, practically all of the surface could be composed of intermetallics.

The contacts with electroplated tin, relatively free of intermetallic when plated, offer a longer service life. But after 4 weeks (without elevated temperature) IMC of about 25 μm thickness can be detected at the copper–tin interface. This too will eventually grow to the surface. The growth rate of the intermetallic on electroplated tin is more rapid than that on *air leveled tin* and *reflow tin* (and commercial *hot dipped tin*). Their cast micro structures with big grains inhibit intermetallic growth at moderate temperatures. This provides longer service time or a thinner tin plating can be used for an equivalent performance.

Intermetallic growth can be retarded by using a “barrier metal” (a metal that diffuses much more slowly with the base alloy and the tin). Nickel has long been plated under gold to act as this diffusion barrier and is similarly effective in tin plating (see Section 2.3). Nickel underplating is often considered as means of slowing down or reducing the formation of CuSn IMC. However, as shown in Section 2.3.3, it not a complete solution to the problem since other IMC may grow on the interfaces, such as Ni–Sn IMC.

A barrier layer may significantly slow down the diffusion of elements other than copper, for example, zinc (zinc oxides at the contact surface are resistive). It was

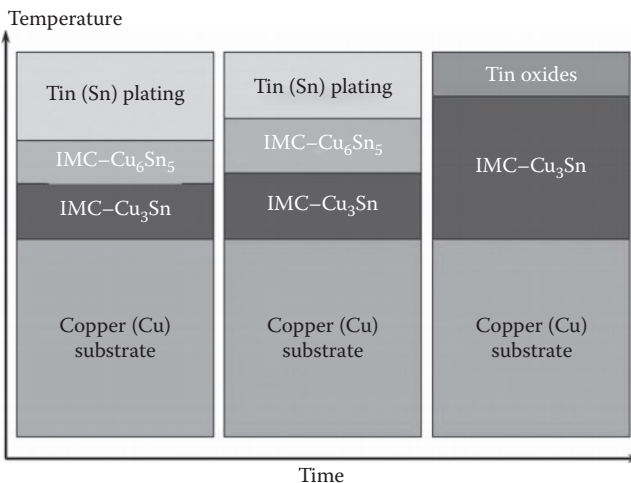


FIGURE 2.12 Intermetallic growth on tin coated copper alloy strip. (Modified from *Copper–Tin Intermetallic Compounds*, Online. Available: <http://www.copper.org/applications/industrial/DesignGuide/coppertin03.html>.)

found that a copper underplating will prevent or impede zinc from reaching the surface; $0.5\text{ }\mu\text{m}$ ($20\text{ }\mu\text{in.}$) is often used on *reflow tin* products. For brasses, $2.5\text{ }\mu\text{m}$ ($100\text{ }\mu\text{in.}$) of copper is effective. Diffusion barriers are often used on *electrotinned* and *reflow tin*. Incorporation of a barrier for commercial *hot-dipped tin* and *air leveled tin* would require a separate operation [50].

2.5.1.3 Resistance of the Contacts with Tin Coating

Tin is characterized by high electrical conductivity, excellent solderability, and relatively low cost. Tin plating is accepted as a method of preventing contamination from the base metal. Tin softness makes it easy to break up films with minute sliding action and relatively light loads. The different kinds of tin coatings have different rates of degradation; some have limited tin thickness, some are less porous, some diffuse faster, and some embody diffusion barriers. Some of these characteristics and all of these differences affect CR.

Contact resistance of tin coatings generally increases with exposure to elevated temperatures. For example, 50 h of exposure of tin plating to a temperature of 125°C does not significantly change the resistance of the coating, but exposure to the same temperature for $\sim 120\text{ h}$ increases the resistance up to $12\text{ }\mu\Omega$, and after 250 h of exposure the resistance of tin plating reaches $105\text{ }\mu\Omega$. After 250 h, the tin on all the samples had formed IMC [52]. Yet there were distinct differences; oxides, films, and surface contaminants from the tin and/or base metal are likely causes. An effective underplating (such as nickel) with a “thick” tin plate would provide better performance.

2.5.2 FRETTING CORROSION AND A MEANS OF PROTECTION

Fretting is a term to describe a small-amplitude rubbing motion between two surfaces. By definition, the amount of relative movement between the contacting surfaces is about $10\text{--}100\text{ }\mu\text{m}$ for fretting. Since $100\text{ }\mu\text{m}$ is a thickness of a sheet of paper, fretting motion is pretty small and hard to see. Vibration and thermal expansion/contraction are the main sources that create fretting motion.

Fretting corrosion is a form of accelerated atmospheric oxidation which occurs at the interface of contacting materials undergoing slight, cyclic relative motion. Fretting and fretting wear can occur on nonelectrical things such as bearings, but fretting corrosion is often associated with electrical contacts [49,53].

2.5.2.1 Fretting Corrosion of Electrical Contacts

A major reason for contact failure with tin surfaces is because of fretting corrosion, a deteriorating process caused by small but repeated micro-motion between contacting surfaces. A higher contact force is effective in minimizing this motion (and thus the fretting corrosion), but cannot be used unless a subsequent increase in the insertion/withdrawal force is acceptable.

In electrical contacts involving nonnoble metals, fretting action can cause rapid increases in CR, which in the worst cases proceeds to virtual open circuits in a matter of minutes.

Fretting corrosion is a build-up of insulating, oxidized wear debris that can form when there is small-amplitude fretting motion between electrical contacts. The

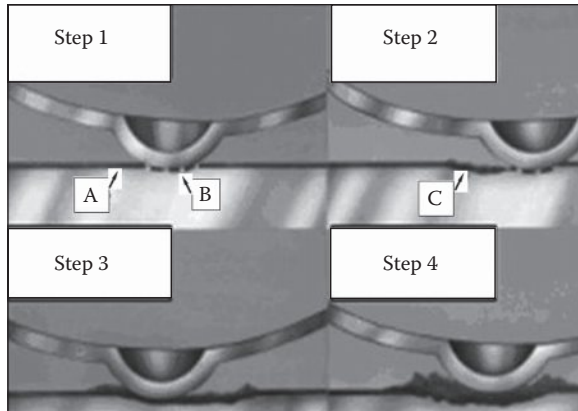


FIGURE 2.13 Fretting corrosion sequence on a tin plated electrical contact. (From *What is Fretting Corrosion*, Delphi, Online. Available: http://www.hlinstruments.com/RoHS_articles/Reliability%20articles/What%20is%20Fretting%20Corrosion%20-%20Delphi.pdf, With permission.)

oxidized wear debris can pile up sufficiently at the electrical contact spots that the electrical resistance across the connection increases significantly. Figure 2.13 shows a magnified, cross-sectional view of the fretting corrosion sequence on a tin-plated terminal contact interface [54].

At the beginning, the thin tin oxide layer cracks under pressure when contact is first made (Step 1). The tin oxide layer is represented as a thin black line (A). Nice, clean tin (B) penetrates through the cracks in the tin oxide layer, making a very stable electrical connection. If the contact spot moves, a microscopic amount from fretting motion (Step 2), the clean tin is exposed to the air and quickly forms an insulating tin oxide film (C).

Every time there is motion at the contact spot, the cycle repeats and more tin oxide wear debris builds up, as shown in Step 3. With continued microscopic fretting movement between contacting surfaces, sufficient insulating tin oxide wear debris can build up so that high resistance and/or intermittent connections can develop (Step 4).

Fretting action seems to produce a surface condition that depends on the hardness of the material. The softer materials suffer more surface damage, pitting, material loss, and generation of wear debris. The harder materials suffer very little damage and not much wear debris is generated. It was shown in Ref. [54] that CR increases at very rapid rates under conditions of fretting corrosion.

All of the more commonly used nonnoble contact materials, such as tin (dull and bright tin, tin alloys) and nickel, experience large increases in resistance during fretting action (small-amplitude cyclic motion). The use of such materials should always be analyzed in the applications where fretting corrosion could occur on electrical contacts as a result of vibration, mechanical motion, or differential thermal expansion.

Lubrication has been identified as a very good way of preventing fretting corrosion [43]. The use of lubricants helps in wear reduction; it aids in the self-cleaning and flushing of wear debris from contacts. Finally and perhaps most importantly, the advantage of lubrication is that liquid lubricants have the ability to exclude oxygen from the contact, thus preventing oxidation of wear debris and freshly exposed

contact material. A more detailed description of the use of lubrication for protecting electrical contacts from fretting corrosion is given in Chapter 4.

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3 Electrical Equipment in a Corrosive Environment

Electrical equipment installed at industrial or commercial facilities could be exposed to both indoor and outdoor environment. Composed of different kinds of materials, both metals and insulators, electrical equipment are subjected to deteriorating corrosion processes, the rate of which strongly depends on the presence of various gases, vapors, and particles and combinations thereof in the surrounding air [1]. The following sections focus on different corrosive factors and the possible response of each of the materials that constitute the equipment to the atmospheric exposure.

3.1 CORROSION FACTORS IN THE ATMOSPHERE

3.1.1 TYPES OF CORROSIVE ATMOSPHERES

Atmospheric corrosion has been defined to include corrosion by air at temperatures between -18°C and 70°C in the open and in enclosed spaces of all kinds. Deterioration in the atmosphere is sometimes called weathering. This definition encompasses a great variety of environments of differing corrosivities. The factors that determine the corrosivity of an atmosphere include industrial pollution, marine pollution, humidity, temperature (especially the spread between daily highs and lows that influence condensation and evaporation of moisture) and rainfall.

Corrosive atmospheres are usually classified into four basic types, although most environments are mixed without any clear borderlines [2]. The four types are: indoor, rural, marine, and industrial, where “indoor” may be considered as the mildest environment. The type of atmosphere may vary with the wind pattern, particularly if corrosive pollutants are present.

3.1.1.1 Indoor Atmosphere

Normal indoor atmospheres are generally considered to be quite mild when the ambient humidity and other corrosive components are under control. However, some combinations of conditions may actually lead to relatively severe corrosion problems. Any enclosed space that is not evacuated or filled with a liquid can be considered as an indoor atmosphere. If not ventilated, such an environment may contain fumes, which could be highly corrosive in the presence of condensation or high humidity.

3.1.1.2 Rural Atmosphere

Rural atmospheres are typically the most benign and do not contain strong chemical contaminants. However, the rural atmosphere can be extremely corrosive to most

construction materials near a farm operation, where by-products are made up of various waste materials. Dry or tropical atmospheres are special variants of the rural atmosphere. In dry climates, there is little or no rainfall, but there may be a high relative humidity (RH) and occasional condensation. This situation is encountered along the desert coasts. In the Tropics, in addition to the high average temperature, the daily cycle includes a high RH, intense sunlight, and long periods of condensation during the night. In sheltered areas, the wetness from condensation may persist long after sunrise. Such conditions may produce a highly corrosive environment.

3.1.1.3 Marine Atmosphere

A marine atmosphere is full of fine particles of sea mist carried by the wind to settle on exposed surfaces in the form of salt crystals. The quantity of salt deposited can vary considerably with wind velocity and may, in extreme weather conditions, even form a very corrosive salt crust. The quantity of salt contamination decreases with distance from the ocean, and is strongly affected by wind currents. The marine atmosphere also includes the space above the sea surfaces where splashing and heavy sea spray are encountered. Equipment exposed to these splash zones are indeed subjected to the worst conditions of intermittent immersions with wet and dry cycling of the corrosive agent.

3.1.1.4 Industrial Atmosphere

An industrial atmosphere is characterized by pollution composed mainly of sulfur compounds such as sulfur dioxide and nitrogen oxides. Sulfur dioxide (SO_2), from burning coal or other fossil fuels, is picked up by moisture and oxidized by some catalytic process on the dust particles into sulfuric acid. The acid settles in microscopic droplets and falls on exposed surfaces (“acid rain”). The primary sources of nitrogen oxides (NO_x) are motor vehicles, electric utilities, and other sources that burn fuels. Nitrogen oxides, hydrocarbons and ozone cause smog (smoky fog) in modern cities.

The contaminants in an industrial atmosphere, together with dew or fog, produce a highly corrosive, wet, acid film on exposed surfaces. In addition to the normal industrial atmosphere in or near chemical plants, other corrosive pollutants may be present. These are usually various forms of chloride which may be much more corrosive than the acid sulfates. The reactivity of acid chlorides with most metals is more pronounced than that of other pollutants such as phosphates and nitrates.

Even in the absence of any other corrosive agent, constant condensation on a cold metallic surface may cause an environment similar to constant immersion for which a component may not have been chosen or prepared for. Electrical systems are often installed in confined areas close to ground level or, worse, below ground where high humidity may prevail. For example, the frame and contacts in an electric junction box were found corroded just 4 years after installation [2]. While the junction box in this example was only at the ground level, the wires coming to the box were buried without additional insulation and were in constant contact with the much cooler ground than ambient air in a room; all these factors together caused the corrosion.

3.1.2 FACTORS AFFECTING ATMOSPHERIC CORROSION

Atmospheric corrosion is accelerated by several environmental factors, such as elevated RH, high temperatures, presence of particulate matter and aerosols, corrosive gases, and so on.

3.1.2.1 Relative Humidity

The most important factor in atmospheric corrosion is moisture, in the form of rain, dew, condensation, or a high RH. RH is defined as the ratio of the quantity of water vapor present in the atmosphere to the saturation quantity at a given temperature, and it is expressed in percent.

A fundamental requirement for atmospheric corrosion processes is the presence of a thin film of electrolyte that can form on metallic surfaces when exposed to a critical level of humidity. The critical humidity level is a variable that depends on the nature of the corroding material, the tendency of corrosion products and surface deposits to absorb moisture, and the presence of atmospheric pollutants. It has been shown, for example, that this critical humidity level is 60% for iron if the environment is free of pollutants.

A thin film of electrolyte is almost invisible, but contains corrosive contaminants, which are known to reach relatively high concentrations, especially under conditions of alternate wetting and drying. In the presence of thin film electrolytes, atmospheric corrosion proceeds by balanced anodic and cathodic reactions. The anodic oxidation reaction involves the corrosion attack on the metal, while the cathodic reaction is naturally the oxygen reduction reaction.

In the absence of moisture, most contaminants would have little or no corrosive effect. Rain may have a beneficial effect as it washes away atmospheric pollutants that have settled on exposed surfaces. This effect is particularly noticeable in marine atmospheres. On the other hand, if the rain collects in pockets or crevices, it may accelerate corrosion by supplying continued wetness to such areas.

Marine environments typically have a high percent RH (%RH), as well as salt-rich aerosols. Studies have found that the thickness of an adsorbed layer of water on a zinc surface increases with %RH and that corrosion rates increase with the thickness of the adsorbed layer. There also seems to be a particular thickness of the water layer that, when exceeded, can limit the corrosion reaction owing to limited oxygen diffusion. However, when metallic surfaces become contaminated with hygroscopic salts their surface can be wetted at lower %RH. The presence of magnesium chloride (MgCl_2) on a metallic surface can make a surface apparently wet at 34% RH, while sodium chloride (NaCl) on the same surface requires 77% RH to create the same effect.

Dew and condensation are undesirable from a corrosion standpoint if not accompanied by frequent rain washing, which dilutes or eliminates contamination. A film of dew, saturated with sea salt or acid sulfates, and acid chlorides of an industrial atmosphere provide an aggressive electrolyte for the promotion of corrosion. Also, in the humid Tropics where nightly condensation appears on many surfaces, the stagnant moisture film either becomes alkaline from reaction with metal surfaces or picks up carbon dioxide and becomes aggressive as a dilute acid.

3.1.2.2 Temperature

Temperature plays an important role in atmospheric corrosion in two ways. First, there is a normal increase in corrosion activity, which can theoretically double for each 10°C increase in temperature.

As the ambient temperature drops during the evening, metallic surfaces tend to remain warmer than the humid air surrounding them owing to their heat capacity. Therefore metallic surfaces do not collect condensation until some time after the dew point has been reached.

As the temperature begins to rise in the surrounding air, the temperature of the metal structures makes them act as condensers. A film of moisture is forming on metal surfaces, and the period of wetness may be much longer than the time the ambient air is at or below the dew point. How long the moisture is deposited on metal surfaces varies with the thickness of the metal structure, air currents, RH, and direct radiation from the sun.

Cycling temperature has produced severe corrosion on metal objects in the tropical climate, in unheated warehouses, and on metal tools or other objects stored in plastic bags. It is advisable to maintain the temperature of metal parts 10–15°C above the dew point since the dew point of an atmosphere indicates the equilibrium condition of condensation and evaporation from a surface. This will guarantee that no corrosion will occur by condensation on a surface that could be colder than the ambient environment.

3.1.2.3 Deposition of Aerosol Particles

The behavior of aerosol particles in outdoor atmospheres depends on their formation, movement, and capture. The concentration of these particles depends on a multitude of factors including location, time of day or year, atmospheric conditions, presence of local sources, altitude, and wind velocity.

The highest concentrations are usually found in urban areas, reaching up to 109 particles per cm³, with the particle size ranging from around 100 μm to a few nm. Size is normally used to classify aerosols, and the other properties can be inferred from size information. The highest mass fraction of particles in an aerosol is characterized by particles having a diameter in the range of 8–80 μm.

Some studies have also indicated that there is a strong correlation between wind speed and the deposition and capture of aerosols; a correlation was also found between chloride deposition rates and wind speeds. Aerosols can be produced either by ejection into the atmosphere (primary aerosol production) or by physical and chemical processes within the atmosphere (secondary aerosol production).

Examples of primary aerosols are sea spray and wind blown dust. Secondary aerosols are often produced by atmospheric gases reacting and condensing or by cooling vapor condensation (gas to particle conversion). Once an aerosol is suspended in the atmosphere, it can be altered, removed, or destroyed.

An aerosol cannot stay in the atmosphere indefinitely, and average lifetimes are of the order of a few days to a week. The lifetime of any particular particle depends on its size and location. Studies of the migration of aerosols inland of a sea coast have shown that typically the majority of the aerosol particles are deposited close to the shoreline (typically 400–600 m) and consist of large particles (>10 μm diameter),

which have a short residence time and are controlled primarily by gravitational forces. The aerosols also have mass and are subject to the influence of gravity, wind resistance, droplet dry-out, and the possibilities of impingement on a solid surface, as they progress inland.

3.1.2.4 Pollutants, Corrosive Gases

The ANSI/ISA Standard S71.04-1985, "Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants," describes how various pollutants contribute to degradation of equipment performance. There are three types of gases that are the prime cause of corrosion of electronics: acidic gases, such as hydrogen sulfide, sulfur and nitrogen oxides, chlorine, and hydrogen fluoride; caustic gases, such as ammonia; and oxidizing gases, such as ozone.

Of the gases that can cause corrosion, acidic gases are typically the most harmful. For instance, it takes only 10 parts per billion (ppb) of chlorine to inflict the same amount of damage as 25,000 ppb of ammonia. Each site may have different combinations and concentration levels of corrosive gaseous contaminants. Performance degradation can occur rapidly or over many years, depending on the particular concentration levels and combinations present at a site. The following paragraphs describe how various pollutants contribute to equipment performance degradation.

3.1.2.4.1 Active Sulfur Compounds

This group includes hydrogen sulfide (H_2S), elemental sulfur (S), and organic sulfur compounds such as the mercaptans (RSH). Even at low concentration levels, they rapidly attack copper, silver, aluminum, and iron alloys. The presence of moisture and small amounts of inorganic chlorine compounds and/or nitrogen oxides greatly accelerates sulfide corrosion. Active sulfurs and inorganic chlorides are considered to be the predominant cause of atmospheric corrosion in the process industries.

3.1.2.4.2 Sulfur Oxides

Oxidized forms of sulfur (SO_2 , SO_3) are generated as combustion products of sulfur-bearing fossil fuels such as coal, diesel fuel, gasoline, and natural gas. SO_2 has been identified as one of the most important air pollutants that contribute to the corrosion of metals. At low concentration levels, sulfur oxides can passivate reactive metals and thus retard corrosion. However, at higher levels, they will attack certain types of metals. The reaction with metals normally occurs when these gases dissolve in water to form sulfurous and sulfuric acids.

Precise methods are available to monitor continuously the amount of sulfur dioxide in a given volume of air. But since only the actual amount of hydrated sulfur dioxide or sulfur trioxide deposited on metal surfaces is important, this is only indirectly related to the effect of sulfur dioxide on corrosion. The pollution levels can also be measured in terms of the concentration of the dissolved sulfate in rain water.

3.1.2.4.3 Nitrogen Oxides (NO_x)

Nitrogen oxides (NO , NO_2 , N_2O_4) are formed as combustion products of fossil fuels and have a critical role in the formation of ozone in the atmosphere. They are also believed to have a catalytic effect on corrosion of base metals by chlorides and

sulfides. In the presence of moisture, some of these gases form nitric acid that, in turn, attacks most common metals.

3.1.2.4.4 *Inorganic Chlorine Compounds*

This group includes chlorine (Cl_2), chlorine dioxide (ClO_2), hydrogen chloride (HCl), and so on. Chemical reactivity of these compounds depends on the specific gas composition. In the presence of moisture, these gases generate chloride ions which react readily with copper, tin, silver, and iron alloys. These reactions are significant even when the gases are present at low concentration levels. At higher concentrations, many materials are oxidized by exposure to chlorinated gases.

Sources of chloride ions, such as bleaching operations, sea water, cooling tower vapors, and cleaning compounds, and so on, should be considered when classifying industrial environments. They are seldom absent in major installations. Particular care must be given to equipment that are exposed to atmospheres containing chlorinated contaminants.

3.1.2.4.5 *Hydrogen Fluoride*

This compound is a member of the halogen family and reacts like inorganic chloride compounds.

3.1.2.4.6 *Ammonia and Derivatives*

Reduced forms of nitrogen (ammonia (NH_3), amines, ammonium ions (NH_4^+)) occur mainly in fertilizer plants, agricultural applications, and chemical plants. Copper and copper alloys are particularly susceptible to corrosion in ammonia environments.

3.1.3 AIRBORNE CONTAMINATION IN DATA CENTERS

The effect of airborne contaminations becomes a very serious issue in the performance of data centers [3]. Airborne contaminations may affect data center equipment in three different ways: chemical, mechanical, and electrical.

Two common chemical failure modes are copper creep corrosion on circuit boards and the corrosion of silver metallization in miniature surface-mounted components. Mechanical effects include heat sink fouling, optical signal interference, increased friction, and so on. Electrical effects include changes in circuit impedance, arcing, and so on.

Most IT equipment are not installed in corrosive environments where it can be exposed to higher risk of failure. Most data centers are well designed and are in areas with relatively clean environments with mostly benign contamination. Most data centers should not experience hardware failures related to particulate or gaseous contamination. Still there are some data centers which may have harmful environments arising from the ingress of outdoor particulate and/or gaseous contamination. In some rare instances, contamination has been known to be generated within the data center.

Reduction of circuit board feature sizes and miniaturization of components are necessary to improve hardware performance. It also makes the hardware more prone to attack from contamination in the data center environment.

The recent increase in the rate of hardware failures in data centers high in sulfur-bearing gases led to recommendations to monitor and control dust and gaseous contamination in addition to temperature–humidity control. These additional environmental measures are necessary to reduce the two most common recent failure modes of copper creep corrosion on circuit boards and the corrosion of silver metallization in miniature surface-mounted components.

It was found that sulfur-bearing gases, even in the absence of moisture, attack silver-forming silver sulfide corrosion products that undermine the integrity of the package. The package with its integrity breeched exposes the underlying silver to further corrosive attack until all the silver in the section is consumed, leading to an electrical open. The silver sulfide corrosion product on the field failed hardware is often visible as needles or nodules, under a low-power microscope [3].

Failure modes due to airborne dust include mechanical effects (obstruction of cooling airflow, interference with moving parts, interconnect interference, etc.), chemical effects (component corrosion, electrical short circuiting of closely spaced features, etc.), and electrical effects (impedance changes and electronic circuit conductor bridging). Even with the best filtration efforts, dust will be present in a data center and will settle on electronic hardware. Fortunately, most dust is benign. Only under rare circumstances will dust degrade electronic hardware.

Harmful dust in data centers is generally high in ionic content such as chlorine-bearing salts. The source of this harmful dust is mainly outdoor dust in the size range of 2.5–15 μm for coarse dust and 0.1–2.5 μm for fine dust. The coarse dust particles have mineral and biological origin, are formed mostly by wind-induced abrasion and can remain airborne for a few days. The fine dust particles are generally the result of fossil fuel burning and volcanic activity and can remain airborne for years. Large bodies of salt water are also a major source of airborne dust contamination in data centers. Sea salt can be carried 10 km (6 miles) inland or farther by high winds present in coastal areas and can damage electronic devices at this range [3].

3.1.4 ZINC WHISKERS

Another form of particulate contamination very harmful to hardware reliability is the zinc whiskers which are the most common electrically conductive particles found in data centers (Figure 1.8(b,c) in Section 1.5). The undersides of some steel raised-floor tiles are coated with zinc to prevent corrosion. The stringers and pedestals supporting the tiles may also be coated with electroplated or hot dip galvanized zinc. Zinc whiskers may grow on both types of coatings, although electroplated zinc is far more susceptible to whisker growth [4,5].

Zinc whiskers may sometimes grow to be 1–2 mm long and become dislodged and airborne, which could happen when the tiles are disturbed during their removal or when pulling or removing under-floor cables. If zinc whiskers are ingested by IT equipment, circuits with voltages higher than about 25 V may suffer electrical short circuiting, arcing, signal perturbations, or catastrophic failures [6]. If zinc whiskers are present, remediation involves replacing the contaminated raised-floor tiles and hiring professionals to clean the data center.

3.2 EFFECT OF ENVIRONMENT ON BARE METALS

It is important to find out how different materials used in the construction of electrical apparatus behave in a corrosive atmosphere. Steel, aluminum, and copper and their alloys are the three main metals used in electrical applications. Steel is typically used in housing, enclosure, and support systems (struts and cable trays). Copper is often used in conductors. Aluminum can be found most often in conductors, conduits, armor, and supports (cable trays). Each of these metals is susceptible to corrosion in different environments. In general, atmospheric, soil and galvanic corrosion represent three major types of corrosion that metals are exposed to in the electrical industry. The following sections contain some specific information on the corrosion performance of the most popular materials in normal atmospheric conditions [7–11].

3.2.1 IRON AND STEEL IN ENCLOSURES, FRAMES, RAILS, AND SO FORTH

Iron, as the major component of steel, is exposed to all kinds of environments. It tends to be highly reactive with most of these because of its natural tendency to form iron oxide. When it does resist corrosion it is due to the formation of a thin film of protective iron oxide on its surface by reaction with oxygen of the air. This film can prevent rusting in air at 99% RH, but a contaminant such as acid rain may destroy the effectiveness of the film and permit continued corrosion. Thicker films of iron oxide may act as protective coatings, and after the first year or so, could reduce the corrosion rate significantly.

The corrosion rates for steel have been determined by the ISO 9223 “Corrosion of metals and alloys—Corrosivity of atmospheres—Classification.” While the corrosion rate of bare steel tends to decrease with time in most cases, the difference in corrosivity of different atmospheres for a particular product is tremendous. In a few cases, the corrosion rates of ferrous metals have been reported to increase with time. Analysis of the exposure conditions generally reveals that if there is an accumulation of contaminating corrosive agents, this increases the severity of the exposure.

Steels containing low amounts of copper are particularly susceptible to severe atmospheric corrosion. In one test conducted over a $3\frac{1}{2}$ -year period in both a marine and an industrial atmosphere, a steel containing 0.01% copper corroded at a rate of 80 $\mu\text{m}/\text{year}$, whereas increasing the copper content by a factor of five reduced the corrosion rate to 35 $\mu\text{m}/\text{year}$. Other tests comparing gray cast iron, malleable iron, and low-alloy steels indicated that their corrosion resistances were approximately the same.

The corrosion behavior of carbon steels is influenced significantly by small variations in copper and phosphorus content. Plain cast iron appears to have a corrosion rate about one half that of 0.2% copper steel in a marine atmosphere. In an industrial atmosphere, structural carbon steel showed a penetration of about 20 μm , copper structural steel about 10 μm , and low-alloy steel about 4 μm after 5 years of exposure.

As indicated in ISO 9223, it is impossible to give a corrosion rate for steel in the atmosphere without specifying the location, composition, and certain other factors. If one can relate exposure conditions to those described in the literature, a fairly

good estimate can be made of the probable corrosion behavior of selected material. However, all aspects of the exposure of the metal surface must be considered. A high-strength, low-alloy (HSLA) steel may show a superior corrosion resistance of 12:1 compared to carbon steel when freely exposed to a mild environment. When the severity or the physical conditions of exposure are changed, the HSLA steel will show less superiority, until in crevices or on the back side of structural forms in a corrosive atmosphere, it will be no better than carbon steel.

Stainless steels (Types 200 and 300), which contain high percentages of nickel and chromium, can keep their shiny aspect without tarnishing for many decades. Steels containing only chromium (Type 400) as the principal alloying constituent tend to rust superficially, but the others are relatively free from surface atmospheric corrosion. Many of them are susceptible to stress-corrosion cracking (SCC) in many common environments.

In electrical applications where steel is usually used as the housing, enclosure, or support system material, corrosion needs to be controlled by measures such as galvanizing, alloying, or painting. Galvanizing steel with zinc provides steel with a sacrificial anode that will continually deplete to protect the more cathodic steel. Alloying steel with chromium allows for the formation of a tightly adhering surface oxide layer, thus turning steel into stainless steel. Painting prevents corrosion by sealing out the agents of corrosion. Various means of protecting steel parts in electrical installations against corrosion are presented in Section 5.7.

3.2.2 COPPER AND COPPER ALLOYS: PARTS OF THE CONDUCTIVE PATH

Bare copper and its alloys are not exposed to the atmosphere in great quantities when compared with steel. However, these materials bring aesthetic value to building construction, in addition to excellent corrosion resistance.

Extensive tests have been conducted on the corrosion resistance of copper and its alloys to various atmospheres. Various alloys were exposed to rural, industrial, and marine atmospheres for periods of up to 20 years. A fairly clear picture can be obtained of the corrosion behavior of copper from data accumulated in these tests and the calibrations of relative corrosivity of the test sites. The addition of tin to copper produces bronze, an alloy that is harder and more wear- and corrosion-resistant than either of the pure metals. Brasses, copper alloys with zinc, are the most numerous and the most widely used of the copper alloys because of their low cost, easy or inexpensive fabrication and machining, and their relative resistance to aggressive environments. They are, however, generally inferior in strength to bronzes and must not be used in environments that cause dezincification.

Copper alloys with nickel are called copper-nickels or cupronickels. The alloys' names usually reveal their basic composition, for example, aluminum bronze, nickel-aluminum bronze, silicon bronze, and so on. Like the copper-tin bronzes, the alloys have a light golden color, high corrosion resistance, and excellent mechanical properties. These alloys may contain several additional alloying elements to provide specific alloy properties. Tin bronzes containing more than 10% tin are generally harder and more corrosion resistant than brass and up to 20% tin is often added. The so-called phosphor bronzes additionally contain small amounts of phosphorus

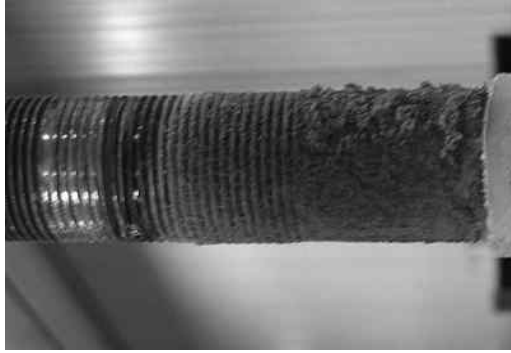


FIGURE 3.1 (See color insert.) Green and blue corrosion of bushing stud made of bare copper.

to further increase hardness and wear resistance; hence, they are often specified for sliding contacts and connectors.

Some alloys are susceptible to specific types of corrosion such as SCC of brass. These types of corrosion contribute to the failure of the material in mechanical respects without significant weight changes or losses in thickness.

Bare copper easily corrodes in atmospheres containing water and acidic vapors, producing white, blue, and green deposits of copper chlorides, sulfates, carbonates, and other compounds. For example, copper (II) sulfate (CuSO_4) is a common salt of copper.

Copper sulfates exist as a series of compounds that differ in their degree of hydration. The anhydrous form is a pale green or gray-white powder, while the hydrated form is bright blue. Both forms may be converted into each other: blue powder will turn white when heated and, conversely, white powder will turn blue when contacted with water. Copper salts have higher electrical resistance than metallic copper, thus degrading conductive properties of copper parts and resulting in failure. An example of extensive corrosion of copper stud inside the bushing is shown in Figure 3.1.

3.2.3 NICKEL AND NICKEL ALLOYS: ELECTRICAL CONTACTS AND PLATING

Electrodeposited nickel and EN are widely used as a protective coating for atmospheric exposure, and some nickel alloys, while selected for other reasons, are also exposed to atmospheric corrosion. Studies of corrosion behavior in different atmospheres showed that nickel tends to be passive in a marine atmosphere. The ratio between the corrosion rate for nickel exposed to the industrial atmosphere and that exposed to rural or marine atmospheres was 28:1. For more about corrosion properties of nickel and nickel alloys in the form of plating and underplating, see Sections 1.1, 1.2, and 2.3.

3.2.4 ALUMINUM AND ALUMINUM ALLOYS IN ELECTRICAL APPLICATIONS

Bare aluminum is used in the electrical industry to manufacture bus bars, transmission and distribution conductors. It is produced in the form of wrought products, extrusions, and castings with a variety of alloying elements to produce the desired

mechanical and electrical properties. Because of technological advances and the favorable price as compared to copper, there has been a continuous growth in the volume, sizes, and varieties of aluminum conductors. Although the increasing use of aluminum bus conductors is credited largely to the economical factors, advances in joining techniques and general experience have prompted its use in many manufacturing, chemical and utility installations.

Aluminum is used in making overhead transmission lines, almost to the exclusion of copper. There are four major types of overhead conductors used in electrical transmission and distribution: AAC, all aluminum conductor; AAAC, all aluminum alloy conductor; ACSR, aluminum conductor steel reinforced; and ACAR, aluminum conductor aluminum-alloy reinforced.

The ACSR cable is a specific type of high-capacity, high-strength stranded cable typically used as a bare overhead transmission cable and as primary and secondary distribution cables. All-aluminum alloy cable was developed to retain the mechanical and electrical properties of ACSR while improving the weight and corrosion resistance characteristics. The excellent corrosion resistance of aluminum in AAC has made it a conductor of choice in coastal areas. ACAR is a composite aluminum–aluminum alloy conductor which is specially designed for each application to optimize the properties.

The favorable qualities of aluminum for its use in electrical applications are its relatively high electrical and thermal conductivities, low density, nonmagnetic properties, ease of drawing down to smaller wire sizes, and high resistance to weathering. Non-current-carrying applications of aluminum are numerous in transformers, capacitors, motors, and other types of electrical equipment.

While pure aluminum has excellent atmospheric corrosion resistance and is used extensively as a cladding material for this very reason, alloys containing copper and silicon as the principal alloying components are often susceptible to atmospheric corrosion and should be used with care. In a rural atmosphere, the corrosion rate for most aluminum alloys is about $0.06 \mu\text{m}/\text{year}$. For alloys containing large amounts of copper, the rate is about twice as much. Changes in tensile strength because of corrosion vary from 0 to $<1\%$ for sheet material.

The aluminum alloys employed for conductor accessories, including drawn, extruded, and cast products, vary with the specific application and the preferences of the individual manufacturer. However, the alloys are generally selected to provide suitable conductivity, high resistance to atmospheric corrosion, galvanic compatibility with electrical conductor (EC) grade aluminum, and satisfactory mechanical properties. Typical suitable alloys are 6061-TG for wrought forms and 356-T6 for castings.

In a marine environment, the differences between corrosion resistance of aluminum alloys may be very large. Some aluminum alloys develop severe pitting and a voluminous white corrosion product under some exposure conditions in a marine atmosphere. The usual corrosion behavior in the atmosphere involves pitting and roughening of the surface with a fairly large decrease in the corrosion rate after the first 1–3 years of exposure. In a harsh industrial atmosphere, aluminum corrosion can be much greater than in the marine atmosphere. In terms of average corrosion rate, the initial rate would be about $0.08 \text{ mm}/\text{year}$, dropping to $<0.3 \text{ mm}/\text{year}$ by 7 years.

Severe pitting has been encountered where aluminum surfaces were contaminated by either alkaline dust or coral dust containing chlorides, followed by condensation. On some of the South Pacific islands, dust collected from the surfaces of sheltered structures, such as those inside aircraft wings, contained 67% chloride by weight.

While designing aluminum equipment, care must be taken to avoid dissimilar metal couples and the attendant galvanic corrosion. Copper and rusty steel are particularly bad when in contact with aluminum. Due to the passive film, stainless steel can be used in contact with aluminum with little expectation of accelerated corrosion, despite the differences in electrolytic potential. In addition, designers should be aware of the possibility that some aluminum alloys may be sensitized to intergranular corrosion by heat treatment. Galvanic corrosion of dissimilar metals connections and a means of protection are described in the Section 2.4.

As would be expected, constant exposure to moisture with a limited supply of oxygen to the aluminum surface leads to rapid corrosion of any aluminum apparatus or equipment component. This is due to the highly reactive nature of aluminum that leads to the formation of oxides or hydroxides. In the presence of oxygen, a protective aluminum oxide film develops on any aluminum surface. This oxide film is substantially unreactive with the normal constituents of the atmosphere. If the film is removed by mechanical or chemical means and the aluminum is exposed to water, then a rapid reaction sets in and large quantities of aluminum are converted into hydroxide and subsequently to oxide.

Most of the 1000, 3000, and 6000 series of wrought alloys, the magnesium, and the silicon magnesium casting alloys are relatively immune to SCC in the normal atmosphere. However, other alloys may be susceptible under certain conditions. This aspect should be investigated carefully by the designer or user if stresses are high and the atmosphere is corrosive.

In the design of aluminum structures, the usual precautions of avoiding crevices or pockets and coupling with dissimilar metals must be observed. In some marine or industrial atmospheres, the aluminum was found perforated at the laps within a few months of exposure. In addition, stress concentrations should be avoided, such as those found in some riveted structures, in the vicinity of welds, and at notches or inside corners. Where it is impractical to avoid connection between dissimilar metals, the aluminum should be electrically insulated from the more noble metal by means of washers, sleeves, and so on. In some instances, covering the noble metal with an organic finish is sufficient to greatly reduce galvanic couple corrosion.

3.3 ATMOSPHERIC CORROSION OF SILVER PLATING

Silver is probably the most widely used contact material available. It has the highest electrical and thermal conductivity of any known metals. As a result of silver's high electrical and thermal conductivity, contacts composed of fine silver work well at current in the low to medium range (1–20 A) where light to moderate contact pressure is available and low contact resistance (CR) is a requirement. Silver has the lowest cost of all precious metal contact materials and is readily formed into various

contact shapes (rivets, buttons, etc.) due to its ductility. Silver plating is a very popular coating for various contact materials, providing a high quality of corrosion protection against many types of environments.

3.3.1 SILVER PLATING CORROSION AND TARNISH

Silver shows good resistance to oxidation and tarnishing except in the presence of sulfur. Sulfur-containing atmospheres will produce silver sulfide that increases CR. There are various forms and degrees of silver corrosion depending on the environment, application, and silver plating quality and thickness [12].

3.3.1.1 Sulfuric Corrosion

Silver corrodes in an environment containing various sulfuric gases such as H_2S , OCS , CS_2 , and SO_2 . The corrosive effect on silver of H_2S and OCS gases is about an order of magnitude stronger than that of CS_2 and SO_2 . However, a product of silver corrosion, silver sulfide can be formed by contact with SO_2 in moist air, but only at SO_2 concentrations two to three orders of magnitude higher than that typical of ambient environments. Hydrogen sulfide (H_2S) is usually present in chemical plants, oil refineries, production of artificial fibers, steel mills, and the paper and pulp processing industry due to process technologies. It was found that even at a minor concentration of H_2S , corrosion produces silver sulfide on the parts in contact with the environment.

Hydrogen sulfide (H_2S) gas practically always is present in an ambient air. In the United States it was found that the concentration in urban and industrial areas of it is in the range of 0.02–5.0 ppb and in remote areas it is in the range of 0.005–0.5 ppb (parts per billion). There is no precise definition of the minimum concentration of H_2S required for tarnishing to be observed on silver, in whatever form the silver is exposed, either bulk or plating. Additional risk of sulfuric corrosion for specific electrical apparatus may come from outgassing of hydrogen sulfide or other sulfuric compounds from seals, gaskets, and other polymers within electrical units and closed housing.

3.3.1.2 Silver Tarnish

By definition, “tarnish” means loss of metallic luster, which is caused by a thin layer of corroded metal. The amount of silver tarnishing is a function of the RH, ambient temperature (T), gas concentration, and time of exposure. Silver will react with extremely low levels of H_2S , and the minimum level will be in the ppb (part per billion) range and even in the ppt (part per trillion) range. Silver and H_2S react to form dark brown or black silver sulfide Ag_2S ; one of the most insoluble salts of silver, this is what causes the tarnish, which has been progressing with time even in facilities with a mild environment, such as manufacturing or assembling plants. An example of a tarnished silver-plated copper bus is shown in [Figure 3.2](#).

After exposure to a corrosive industrial facility environment, the tarnish film on a silver-plated copper bus grows very thick, and dark brown and black silver sulfides form flakes on exposed surfaces ([Figure 3.3](#)).

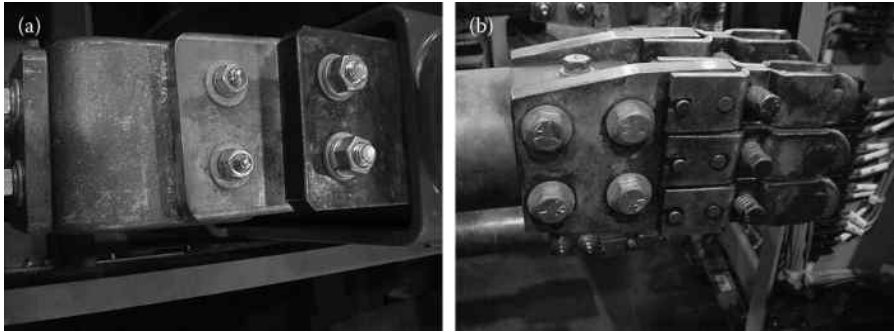


FIGURE 3.2 (See color insert.) Tarnished silver plating on copper bus after various periods of service at industrial facility (a) and of storage at a manufacturing facility (b).

Some factors could accelerate the development of silver tarnishing during transportation, storage, and exploitation of the equipment:

- Elevated temperature
- High humidity
- Light (UV)
- Ozone rate in the atmosphere
- Presence of salts on the surface, possibly due to handling with naked hands

An additional source of sulfuric gases may be an inappropriate packing material, because certain cardboards contain sulfur. The packing material should pass a special silver tarnish test [13] to not cause an additional silver tarnishing.



FIGURE 3.3 (See color insert.) Heavy silver plating tarnish on copper bus after several months in service at an industrial facility.

3.3.1.3 Silver Whiskers

When a thick layer of Ag_2S is formed on silver plating and the parts are exposed to a high temperature and hydrogen sulfide, the new process of growing thin filaments (whiskers) begins (Figure 3.4).

Silver whiskers grow practically everywhere on corroded silver plated parts of switchgear, but more intensely in areas with higher temperature, such as bus joints and sliding contacts, outside edges and corners of the contacts. Temperature gradients in these areas may encourage this phenomenon. Silver corrosion results in a high resistance, which produces more heat, which in turn stimulates further tarnishing and the growth of whiskers [14]. A detailed description of the silver whisker phenomenon is given in Section 3.5.

3.3.2 RED-PLAQUE CORROSION

A special type of copper corrosion called “red plague” has been known for decades. Copper is susceptible to the formation of red cuprous oxide when stored or used in a moist or high humidity environment. Red plague corrosion was first documented in reports on corrosion dated 1965 or so, and has been found on a regular basis since then both in the United States and Europe.

When silver is plated over copper, there can be an accelerated corrosion of the copper caused by defects in the silver plating through galvanic action (Section 2.4). Imperfections such as pinholes, pores, and breaks in silver plating allow moisture



FIGURE 3.4 (See color insert.) Finger cluster of corroded breaker after 2 months of service in a paper mill facility (pulp processing mill).

and oxygen to penetrate the silver plating. The sacrificial corrosion of copper occurs in a galvanic cell of silver (cathode) and copper (anode), resulting in the formation of red cuprous oxide (Cu_2O). Secondary corrosion products are black cupric oxide (CuO) and copper hydroxides (bluish green). This reaction is promoted by the presence of moisture (H_2O) and oxygen (O_2) at an exposed copper–silver interface, such as an exposed conductor end (crimp terminations). The process is caused by poor plating quality control (pin-hole, porosity, thin coating) or mechanical damage during stranding or handling (scratches, nicks, abrasion). In the cables copper corrosion is accelerated by penetration of moisture, oxygen, flux residue, and solvents under the insulation jackets.

The color of the deposit may vary depending on the amount of oxygen available, commonly noted as a red and reddish-brown surface discoloration—hence the term “red plague.” Once initiated, the sacrificial corrosion of the copper base conductor can continue indefinitely in the presence of oxygen (O_2) [15–17].

The corrosion known as “red plague” is identifiable by the presence of a brown-red deposit on the surface. It was found that copper wires with silver plating $<1\text{ }\mu\text{m}$ thick are susceptible to red plague corrosion. An example of corrosion that may be identified as red plague is shown in Figure 3.5. Silver flash plating disappeared from the copper bus after being shipped overseas and left copper unprotected and exposed to oxidation and corrosion.

Occurrences of red plague corrosion have periodically affected aerospace and defense programs for >40 years. The risk imposed by red plague is related to the extent of corrosion. Sufficiently advanced corrosion can lead to electrical and/or mechanical failure as copper is consumed within affected conductors. A major risk to system performance therefore exists when primary signal or power conductor paths are affected. Wire and cable industry process improvements have not eliminated the problem.



FIGURE 3.5 (See color insert.) Silver-flash plated copper bus after being shipped overseas. (Courtesy of Finishing.com, Online. Available: <http://www.finishing.com/280/03.shtml>; the picture is taken by Steve Whatley.)

Concerns about galvanic corrosion of silver-coated copper wire are specified in many documents used by NASA, the European Space Agency (ESA), military, and aerospace, for example, ASTM B 961-08, “Standard Specification for Silver Coated Copper and Copper Alloy Stranded Conductors for Electronic Space Application”; ECSS-Q-ST-70-20C, “Determination of the Susceptibility of Silver-Plated Copper Wire and Cable to ‘Red-Plague’ Corrosion”; SAE AIR4487, “Investigation of Silver Plated Conductor Corrosion (Red Plague)”; and many others.

The Red Plague Control Plan (RPCP) [17] determines silver coating requirements to mitigate the development of red-plague corrosion. Primary and shield conductors should be plated with not less than $2\text{ }\mu\text{m}$ ($80\text{ }\mu\text{in.}$) silver plating on average. After stranding, the silver coating thickness on each of the individual conductor strands shall not be $<1\text{ }\mu\text{m}$ ($40\text{ }\mu\text{in.}$).

The European Space Agency (ESA) responded to the issue of red plague by requiring lot sample verification that the silver coating has a minimum coating thickness of $2\text{ }\mu\text{m}$ ($80\text{ }\mu\text{in.}$) for all critical wiring installations utilizing silver-coated copper wires.

3.3.3 UNDERPLATING CORROSION

When silver is plated over copper with some areas of bare copper exposed, underplating corrosion may occur (Figure 3.6). In the example of underplating corrosion [18] the finger clusters of medium voltage circuit breaker (MV CB) were silver plated only along the edges, which left large amounts of exposed copper. The CBs were installed in a vented air-conditioned trailer. Normally, these contacts cycled once daily, on in the morning and off at night. When energized, the operating temperature

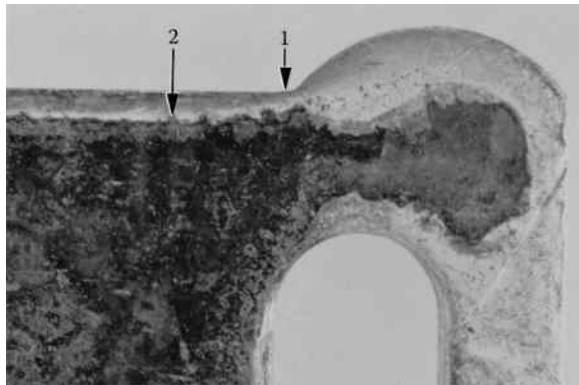


FIGURE 3.6 (See color insert.) Underplating corrosion: silver plating on the contact surface (1), and corroding copper under silver plating (major component—copper carbonate hydroxide) (2) (4× magnification). (From *Under Coating Corrosion of Silver Plated Copper in a Circuit Breaker*, Online. Available: <http://www.corrosionlab.com/Failure-Analysis-Studies/20034.under-coating.silver-plated-copper.htm>, courtesy of Corrosion Testing Laboratories, Inc., Newark, DE. With permission.)

inside the box was 75–90°C. When cycled off, the box was cooled to ambient temperature overnight. The contacts carried either 4160 or 13,800 V AC.

There are two basic areas on the finger cluster shown in [Figure 3.6](#): area 1 is silvery metallic in color (typical of silver plate), while area 2 is green in color (typical of corroding copper). Corrosion products penetrated under silver plating, causing it to flake off. To prevent underplating corrosion, silver should be plated on the whole finger cluster area, leaving no exposed copper.

3.3.4 EFFECT OF SILVER PLATING THICKNESS AND QUALITY ON SULFURIC CORROSION

Silver sulfide (Ag_2S) is a major product of silver corrosion in atmospheres containing sulfuric gases. Silver corrosion recognized as “tarnish” is the very first step in silver sulfuric corrosion, when the corrosion layer forms a dark thin film, which can relatively easily be removed with a tarnish cleaner or scotch-bright material. As soon as a significant layer of silver is consumed, silver sulfide is formed on the surface as a heavy dark gray or black flaking deposit. The formation of silver sulfide is linear with time.

It is well known that corrosion resistance of electroplated silver strongly depends on plating quality. Specific types of plating the bath may produce plating with higher corrosion resistance or lower corrosion resistance. For example, plating without surfactants at lower current density (CD) would produce more loose and porous plating [19]. Surface conditions, such as roughness and cleanliness, play an important role in plating corrosion resistance. A combination of two conditions, poor quality of the plating characterized as loose and porous and exposure to humid atmosphere, may result in “red plague” corrosion.

It was found that CR is strongly influenced by the corrosion film thickness [20–21]. It was also concluded that silver coating thickness is the most important factor in corrosion resistance. If the silver coating is too thin or of low quality, the corrosion film will include copper corrosion products and its presence will always be detrimental to the contact. Contacts with a thin silver coating behave almost like bare (unplated) copper contacts.

The thicker the silver plating is, the better the base material is protected from corrosion, since a thicker plating is less porous and does not allow corrosive gases to penetrate through the plating. Silver flash, which usually has a thickness of several tenths or even hundredths of microns, would be consumed in a corrosive atmosphere very fast.

3.3.5 CORROSION OF A COPPER BUS WITH FLASH SILVER PLATING

Copper is often used in various applications together with silver flash, which is a very thin plating that does not provide long-lasting protection from corrosion, particularly in environments with relatively high concentration of corrosive gases or particulate matter. The preferred environment for a silver flash bus is considered to be the office or environmentally controlled light industrial environment. These environments are typically controlled and are relatively free from corrosive contaminants in the area around the equipment. Silver flash plating of about 0.025–1.25 μm may not show any visible signs of tarnish after being stored for many months at the facility with a clean environment ([Figure 3.7](#)).



FIGURE 3.7 (See color insert.) Copper bus with silver flash stored for 12 months at a manufacturing facility with clean environment.



FIGURE 3.8 (See color insert.) “Blue” and “green” corrosion of copper with silver flash on bus bars (a) and plate (b).

The use of silver plated/coated bus is not recommended in the industrial facilities with the potential for excessive corrosion rates, such as wastewater treatment plants (WWTPs), pulp and paper processing and manufacturing plants, chemical industrial facilities, and so on. The use of silver flash in corrosive environment may result in red plague copper corrosion as shown in [Figure 3.5](#). Examples of “blue” and “green” copper corrosion of the CB bus stabs coated with silver flash are shown in [Figure 3.8](#).

3.4 EFFECT OF SILVER CORROSION ON CONTACT RESISTANCE

3.4.1 SILVER TARNISH AND CONTACT ELECTRICAL RESISTANCE

Silver sulfide is not a conductive material and having a contact surface covered with a corrosion layer may significantly decrease the electrical conductivity. The effect of

corrosion on the electrical properties of the contact mainly depends on the thickness of the corrosion layer. The focus of this section is on a relatively benign and less harmful stage of silver corrosion—silver tarnish—with a very thin layer of silver sulfide on the contact surface.

3.4.1.1 Thickness of Silver Tarnish

Air quality, ambient temperature and humidity are two most important factors influencing the thickness of silver tarnish. Usually, the thickness of a silver plating is in the range of 6.25–12.5 μm . The longer the silver plating is exposed to corrosion, the thicker the tarnish film that is formed. The color of the silver plating is changing gradually after various periods, from 1 month to 5 years of exposure to the atmosphere of a common manufacturing facility storage. After only several months in storage, silver tarnish is very well seen as a dark yellow tint. In <3 years the discoloration of the plating is very strong and in 5 years the plating has a heavy brown deposit (Figure 3.2).

When exposed to the corrosive industrial environment of a paper mill, the tarnish film is very thick, forming a dark brown/black scale in a couple of months of exposure (Figure 3.3). The only silver that will not tarnish would be the one kept in vacuum or has a coating on top to isolate its surface from the atmosphere.

Silver sulfide is not an insulating substance; it is a semiconductor and may therefore conduct electricity. However, since the electrical resistivity of silver sulfide (Ag_2S) is $\sim 100,000$ times higher than that of silver (15–20 $\mu\Omega\text{-cm}$ for Ag_2S vs. 1.6×10^{-4} $\mu\Omega\text{-cm}$ for Ag), it reduces the surface conductivity of the silver even if a very thin film is formed.

To what extent silver tarnish will effect electrical conductivity depends on the thickness of the tarnish. When silver contacts are used, one of the factors that make them good is that the silver is soft and when rubbed against the other contact, it cleans itself and smears, so good metal–metal contact can be sustained. However, if the contacts are not designed to do this, there could be a longer-term problem with an accumulation of low conductivity sulfides. The influence of sulfide corrosion on electrical contact was studied in detail in Ref. [22] because of a growing concern for the safety of satellites stored on the ground for a long time before launching.

Initially, sulfur rapidly attacks the silver surface. Once the sulfide layer becomes continuous (100% of the surface is covered), growth takes place on the sulfide surface. Thereafter, sulfidation is limited by the rate at which the sulfur-containing gas is supplied to the surface or the rate at which silver, a highly mobile ion, diffuses through the sulfide layer. It was concluded that most electrical connectors can tolerate some sulfide on their surfaces. Silver sulfide grown on a pure silver surface is soft and malleable, being easily pushed aside even under low load. This would allow enough micro contacts to produce a low CR.

Although the thickness at which tarnish begins to noticeably degrade the electrical properties of the circuit is not well established, it was found that the silver sulfide layer becomes continuous at a thickness of about 150 Å. Tests examining the electrical conductivity of silver seem to indicate that 200 Å would be a reasonably conservative estimate of the thickness at which electrical properties begin to deteriorate.

The data presented in Ref. [21] can be used to evaluate the approximate “safe” storage time in an environment with very low concentration of H_2S where the

electrical contact performance remains acceptable. For example, in urban and industrial areas the concentration of H_2S is found to be in the range 2–5.0 ppb. At lower concentrations of H_2S contamination, electrical properties of the contact will not be deteriorated by the tarnish film formed. However, at higher end of the H_2S concentration (5.0 ppb), the tarnish film able to deteriorate the electrical properties of the contact will be formed only for 2000 h (83 days or <3 months) at room temperature and >75% RH. At higher temperatures the tarnish film will grow faster.

The data on the thickness of corrosion film forming on silver in three types of field environments, according to MFG test specifications, are given in Ref. [23]. It was found that in a mild Battelle Class II environment (with 10 ppb of H_2S), a corrosion film with thickness greater than 1000 Å on silver will be formed for <1 year. It was shown that the formation of a 1000 Å thick corrosion film on silver may lead to an increase of the contact electrical resistance to >10 mΩ after exposure to a mild office environment only for 1+ year. For a more harsh environment with 2 ppm H_2S , a corrosion film of 500 Å is formed only for 1000 h (~40 days) [24].

The relationship between the CR and the exposure time to H_2S gas was studied in Ref. [25] as a function of the film thickness and the time of exposure to 3 ppm of H_2S at 40°C and 80–85% RH. In such conditions and on exposure for less than 100 min, the corrosion film thickness will grow to 500 Å.

3.4.1.2 Effect of the Current Load and Mechanical Load on the Corroded Contact Resistance

The CR of the contact covered with corrosion film depends on the contact load (force), which varied from 1 to 100 g. This means that Ag_2S is mechanically weak. In Ref. [25] the current was found to strongly affect the CR and the size of the contact areas; that is, the CR was lowered with increasing the current load. Also it was determined that thin corrosion films on silver do not always cause high CR in high-current applications despite their high resistivity.

Depending on the thickness of silver tarnishing, it can have various degrees of severity. If the parts are just slightly yellow and the discoloration does not evolve more, then it should not be considered as seriously damaging for contact electrical properties. Conductivity is not affected by a light yellowing. In other cases, tarnishing can lead to dark brown and black colors. This coloring can be partial or total depending on the conditions of the storage or use (finger marks, opened packing, etc.). If the discoloration is in constant evolution, it should be seen as a sign of the presence of a source of sulfuric gas in the immediate environment of the products. In this case, conductivity has a very good chance of being degraded.

The reactions of atmospheric pollutants with silver-based contact materials also produce corrosion products which adversely affect the contact's electrical behavior. In Refs. [25,26] three silver-based contact materials, Ag/Cu/Ni, Ag/Ni, and Ag/MgO/NiO, were exposed to an accelerated corrosion environment containing SO_2 , H_2S , NO_2 , and Cl_2 , with a maintained elevated temperature and high humidity. Both electrical degradation and corrosion film growth characteristics were studied as functions of exposure time. Contact resistance increased rapidly with the formation of a growing corrosion film made mostly of silver chlorides and silver sulfides.

3.4.2 TECHNIQUES OF TARNISH CLEANING

Due to the detrimental effect of silver tarnish on electrical contact performance, it is important to protect silver plating from corrosion. If a corrosion film is already formed, it should be timely and properly removed from the contact surfaces. Different techniques have been developed to delay contact corrosion, but whatever be the kind of antitarnish treatment applied, it should not interfere with the electrical properties of the coating.

The techniques of cleaning silver are as old as jewelry made of silver. The first published recommendations came from Theophilus of the 12th century: “If . . . silver . . . has become blackened with age, take some black charcoal, grind it very fine, and sift it through a cloth. Take a linen or woollen cloth that has been wet in water and put it on the charcoal. Lift it up and rub the . . . silver all over until you remove all the black stain. Then wash it with water and dry it in the sun or by a fire or with a cloth. Then take white chalk and scrape it very fine into a pot and, dry as it is, rub it with a linen cloth over the . . . silver, until it recovers its pristine brilliance” [27].

It would be helpful to correlate the color of a tarnish film with its thickness, and be able to determine when the corrosion film may begin to deteriorate the electrical properties of the contacts. In Ref. [28] it was shown that evaluation of tarnish film color may be used to assess the tarnish formation and to relate the color change to the degree of tarnishing. The results of this study correlate very well with the behavior found for the weight increase (thickness of the tarnish layer) versus either the hydrogen sulfide concentration or exposure time.

Tarnish cleaning products may have different consistency. They can be solids (such as the common washing soda) that dissolve in water, in which case tarnish is removed using electrolytic action; they could be fluid that requires one to rinse off the chemicals used for tarnish film removal. Some silver cleaning materials (abrasive fluids) have been tested for removing a heavy tarnish (0.5–1 μm) [29].

It was found that calcium carbonate, γ alumina, and chromium oxide suspended in deionized water and containing nonionic surfactant helped remove tarnish successfully and caused the least amount of damage to the silver. The use of cleaning powder is not recommended. Overzealous pressure when cleaning with powders may help remove significant amounts of silver, which ultimately will wear through the plating completely.

The antitarnish products could be semisolid (cream, paste, and emulsion). Some cleaners that are available in paste or emulsion not only remove tarnish but contain tarnish inhibitors.

The use of chemical dip solutions (often referred to as silver dip) is effective, but requires much attention:

- Silver-plated parts in the dip solution should not stay in solution for >10 s.
- If heavy tarnish is treated, the surface of the restored silver may have a matt finish.
- Dip solutions can stain or even etch the materials other than the silver; any drops of dip solutions that fall on these materials should be rinsed off immediately.
- Silver-plated parts should be washed and dried thoroughly after cleaning with dip solutions.

Several criteria should be applied to select the best tarnish cleaner to use in the service maintenance and refurbishment of silver-plated copper electrical contacts. The best products among many available in the market are those that satisfy the following conditions:

1. Clean the tarnish instantly
2. Contain no abrasives and therefore do not harm silver plating
3. Do not require rinsing in soapy water or any other fluid
4. Applied by a simple procedure and without spill
5. Can be applied without any special employee protection

Some products provide cyanide-free instant tarnish removal for pure and plated silver, return substrate to as-plated appearance in most cases, and rejuvenate surfaces and eliminate the need for costly stripping and replating.

3.5 SILVER WHISKERS: A MYSTERIOUS AND DANGEROUS PHENOMENON

3.5.1 HISTORY OF SILVER WHISKERS

Thick hair-like formations on the conductive parts of electrical equipment have been seen from the 1920s onwards and have caused a number of violent failures, but are not yet practically studied and clearly understood. Only a few papers describe the extensive growth of silver whiskers at a synthetic fiber factory in France [30], Kraft liner-board mill in southeastern United States [31], and Coking plant in the United Kingdom [32]. In all these locations hydrogen sulfide (H_2S) was present in the atmosphere.

The first and the only extensive study of silver whiskers was prompted by the failures at a synthetic fiber factory [30] in 1982. The atmosphere in the factory had H_2S levels of several dozens of ppm, which is very high by any standard. No other contaminants, such as pure sulfur and SO_2 , were found in the environment. As later confirmed by analysis, the contaminated parts were heavily sulfidized. After the failure of electrical equipment, improved ventilation of the premises was incorporated, but did not bring the expected results, and although the level of H_2S was reduced to 0.5 ppm, incidents began to occur again.

In the course of a thorough periodic examination of the suspect equipment, “metallic”-looking filaments, some of them >1 cm (0.4”) long, were observed on the supports of certain fuse-holders. In some cases, large numbers of very fine filaments appeared in tufts; in others, they looked like needles growing at right angles to the metallic surface. This phenomenon was found not only on silver-plated copper parts but also on contacts made of AgNi alloy. The filaments grew most readily on the outside edges and corners near contact zones, but not necessarily on the points thought to be the hottest.

Silver whisker growth was successfully reproduced in a laboratory setup, in which different levels of H_2S (50 and 1 ppm) were maintained. The temperature of the chamber was stabilized at $40^\circ C$ and the RH was 40%. The test was carried out on a triple-pole fuse-holder, whose poles, linked in series, had a current corresponding to the nominal intensity of the apparatus (50 amp) passing through it. The supports

of the fuse-holders were made of copper, electroplated with silver of 10 μm thickness. The cylindrical ends of the fuses were also silver-plated.

In the course of the experiment it was found that the whiskers started growing as soon as a fairly thick layer of silver sulfide is formed on the silver-plated parts. The only difference in H_2S level of 20 or 1 ppm was that the formation of corrosion film took longer for lower level of gas.

When the temperature of the sample remained below about 140°C , typical Ag_2S crystals with length not exceeding a few μm have been growing on the fuse-holder, but no filament growth was observed. As soon as the temperature of the support rose above 140°C in a matter of hours, minuscule filaments began to appear. In 24 h, these filaments had grown to 10 mm. They looked exactly like the filaments on the apparatus at the factory.

Each filament was made up of a bunch of fibers of about 1 μm diameter. The diameter of the filaments measured at the base varied between 10 and 70–80 μm . The sections where the filaments seem to grow best were on the outside edges and corners. The speed at which filaments grew in these conditions reached about 1 mm/h or 0.3 $\mu\text{m/s}$. The whiskers were made up of Ag and S but with much less sulfur than there is in Ag_2S . It was assumed [30] that silver whiskers have been partially transformed into silver sulfide, which covered filament surfaces exposed to an ambient H_2S .

Another observation was given in Ref. [31] that under proper conditions there is no restriction on the length to which the whisker could grow. There are other observations showing that silver whiskers may grow at room temperature as well. In Ref. [32], the sample was laid on a bench in the laboratory and subjected to heavy concentrations of several corrosive gases, including hydrogen sulfide, at ambient temperature. After some time, it was found that whiskers up to 4 mm in length had developed.

3.5.2 FACTORS THAT AFFECT THE GROWTH OF SILVER WHISKERS

Based on the observations and experiments described in Refs. [30–37], several factors initiating and accelerating the growth of silver whiskers may be determined.

3.5.2.1 Environmental Factors

It is obvious that H_2S gas even at very low levels is a primary factor to initiate whiskers growth. A layer of silver sulfide (Ag_2S) of a certain thickness needs to form for whiskers to start growing. Elevated temperature (above 140°C) of the parts seems to accelerate the growth. The influence of elevated humidity is not defined yet. The influence of gases other than H_2S present in the atmosphere on silver sulfide formation has not been thoroughly investigated. It was shown in Ref. [37] that the presence of NO_2 greatly enhances the silver corrosion rate, which was 5 times faster than that expected when the combination of H_2S and NO_2 is present in the atmosphere. However, too fast corrosion process would consume silver plating completely before the whiskers may develop.

3.5.2.2 Plating Factors

The role of silver plating thickness in silver corrosion was studied in Ref. [19]. The test was performed on three sets of model contacts made from copper electroplated with

2, 5, and 20 μm of silver precorroded for 1, 5, and 10 days, respectively, in an atmosphere containing a mixture of Cl_2 , NO_2 , and H_2S (Battelle class III). Then precorroded contacts were powered and tested under the normal force. It was found that the whiskers start growing from the corrosion layer formed in an atmosphere containing H_2S concentration as low as 0.1 ppm. With the thinnest silver coating (2 μm) covered with the thickest corrosion film (10 days in the Battelle chamber), silver whiskers formed just outside the conducting area of the anode in the 15 min test. At the time the whiskers were forming, the temperature of the contacts was close to 160°C.

3.5.2.2.1 Thickness of Ag_2S Film

The effect of silver sulfide film thickness on the start of whiskers growth was studied in Ref. [36]. Until the thickness of the silver sulfide film reached 0.075 μm (750 Å), no whiskers were found. Such a thickness of the tarnish film is formed in 1 week on silver exposed to 20 ppm H_2S at room temperature in humid air (75% RH).

3.5.2.2.2 Base Material

The role of base material in whisker growth is not clear yet. Silver whiskers are found growing not only on silver-plated copper but also on Ag90/Ni10 alloy [30]. In Ref. [35], whisker formation was observed on coupons made of silver with purity 99.9–99.99%. In this experiment, silver coupons were exposed to an atmosphere containing 3 ppm H_2S at 40°C and 80–85% RH.

3.5.3 FAILURES IN ELECTRICAL EQUIPMENT CAUSED BY SILVER WHISKERS

Exposure of silver-plated parts of the CB to hydrogen sulfide results in the formation of a thick dark brown or black layer of silver sulfide and multiple clumps of silver whiskers (Figure 3.5). In most cases, the presence of corroded silver and whiskers led to the thermal failure of the CB.

In recent years, the growth of silver whiskers was seen on the corroded silver-plated parts of LV CBs in service in the control room of a pulp recycling plant [12]. This happened 1 year after the factory switched from one pulp processing technology to a different process, which used a chemical reaction that produced H_2S gas. The level of H_2S in the control room was detected to be in the range 0.5–2 ppm. Since then, every 2–3 months the maintenance personnel at the plant have performed cleaning of the units having extensive corrosion and whiskers growth. Within 2 months after thorough cleaning, two LV CBs failed after violent thermal runaway (Figure 3.9).

After the failure, the failed breakers were disassembled, and clumps of the whiskers were found everywhere inside the current-carrying path of the breakers. Almost 12 g (4 oz) of whiskers were collected and studied using SEM/EDS techniques [14].

3.5.4 STUDY OF THE SILVER WHISKER PHENOMENON

3.5.4.1 Visual Appearance of the Whiskers

Most of the whiskers have the shape of a single thick thread, which may eventually split into several thinner filaments. The filaments have many different colors,

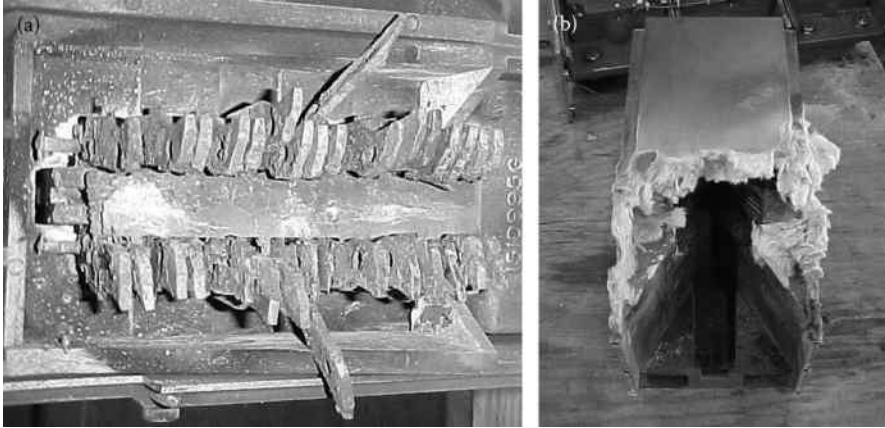


FIGURE 3.9 (See color insert.) Images of the parts of the CB failed due to heavy corrosion and growth of silver whiskers: finger cluster (a) and arc chute (b).

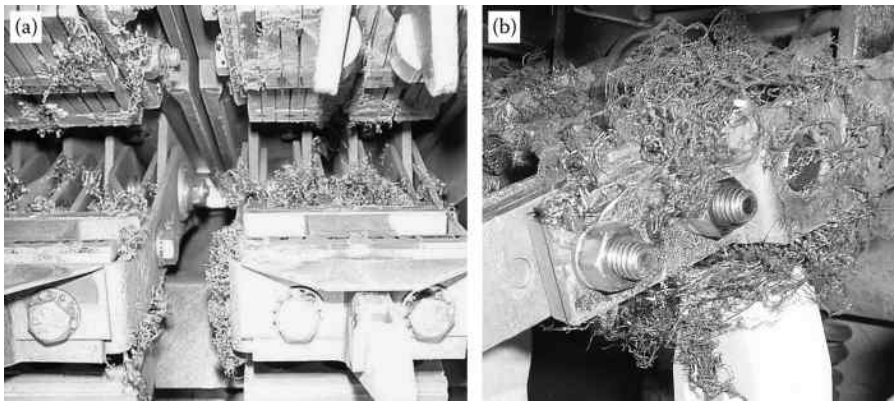


FIGURE 3.10 Silver whiskers inside failed breakers: (a) on the contacts; (b) on the bolted connections.

shapes, and sizes ranging from tiny thin “dawn”-looking formations to thick and strong threads, which are bound together into large tufts and clumps (Figure 3.10).

The color of the whiskers ranges from a shiny silver and gold luster to dull dark gray or black. The color of some whiskers changes along the length of the filament from bright silver to bright yellow or from metallic luster to dark dull gray or black. The thickness of the whiskers is up to 1 mm (0.04 in.). Some of the whiskers shown in Figure 3.11 grew as long as 5–10 cm (2–4 in.).

3.5.4.2 Morphology

The morphology of the whiskers was studied by using SEM. The samples for SEM analysis were selected from whisker clumps under stereo microscope magnification.

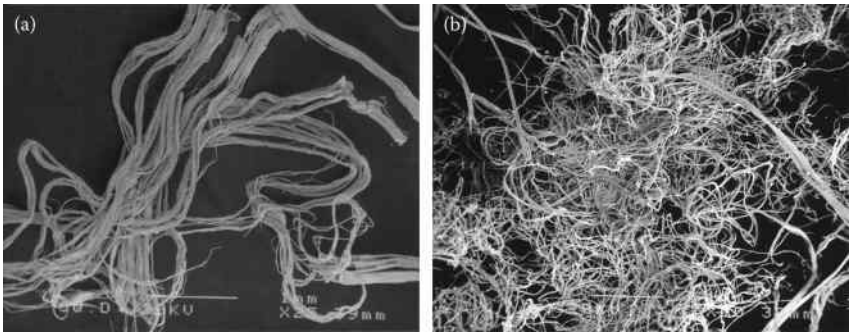


FIGURE 3.11 Extra long and thick whiskers (a) and extra thin whiskers (b) with silver luster.

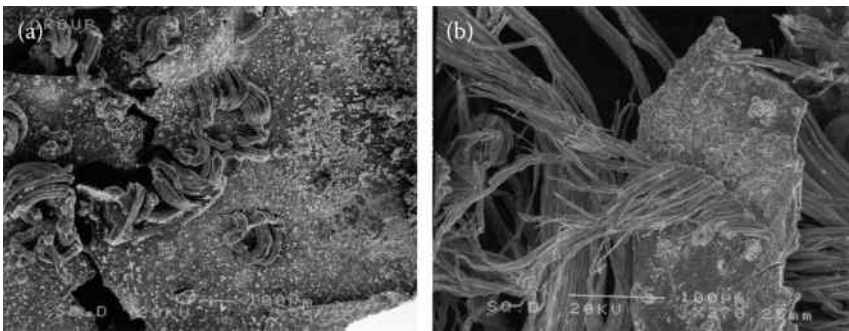


FIGURE 3.12 Silver whiskers, growing from the flakes: “nursery” (a), and pictured together with thicker (older) whiskers (b).

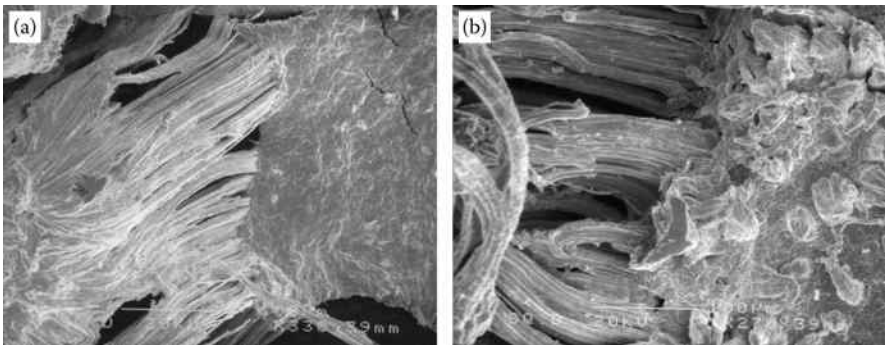


FIGURE 3.13 Silver whiskers at the roots of growth: (a) wide flat whiskers; (b) multi-strand round whiskers.

SEM photographs of the whiskers at high magnification in Figures 3.12 and 3.13 show “baby” whiskers at the beginning of the growth. They start extruding from the flakes as a group of many thin straight or curly filaments of different thickness, which may then fuse together into a thick filament.

The color of the whisker surface (with metallic luster or dull and dark) seems to correlate well with the surface morphology. The surface appearance of the whiskers with a metallic luster and dull dark color is significantly different [14]. Under high magnification, various groups made of long threads have been found. Each thread eventually splits into several thinner filaments. Some filaments are bound together, forming agglomerates. The thickness of the whiskers varies from 2–4 μm to almost 1000 μm (1 mm).

3.5.4.3 Chemical Composition

Chemical composition of the whiskers was determined by EDS. X-ray analysis of chemical composition of the whiskers [14] is based on elemental composition of a relatively thin upper layer of the whiskers, since EDS techniques provides quantitative analysis with a sampling depth of 1–2 μm . It was found that whiskers having silver luster are made of 94–99.4% of silver. Some of the whiskers with silver luster also contain up to 4.5% copper. The whiskers with yellow luster have higher content of copper (from 7% to 33%).

The chemical composition of the whiskers also correlates well with the color of the whiskers. Sulfur (S) was found on the surface of the whiskers with the content of S varied from traces (on the whiskers with silver luster) and up to 9% sulfur. That much sulfur was found on the whiskers with dull dark color, which is enough to constitute a pure silver sulfide on the surface. When the whisker has one yellow end and the other end is dark, the content of sulfur along the whisker is growing gradually from 1.8% on the yellow end up to ~4.5% on the dark end.

The difference in color and composition of the long and thick whiskers may be explained by the different temperature conditions of the whisker “birth place.” The silvery whiskers could grow much faster in hotter areas and be exposed to H_2S for a shorter period of time than same-size whiskers, which grew slower in cooler locations. The whiskers that have been exposed to corrosive gas for a longer time have a thicker silver sulfide layer on the surface and therefore are dark.

The composition of the whiskers is compared with the composition of the flakes collected from the surfaces of the corroded conductive parts of the breaker. The flakes contain silver, copper and sulfur in proportions corresponding to the mixture of silver and copper sulfides.

3.5.4.4 Chemical Composition of the Whisker Cross Section

One of the samples for x-ray analysis was prepared to determine the internal composition of the whisker. The sample was cut through the base metal, thick corrosion layer, and small whisker growing from the corrosion layer. All parts of the sample, where chemical compositions have been determined, contained three elements: copper (Cu), silver (Ag), and sulfur (S). The composition was measured along the line starting from the base metal made of pure copper and then across the corrosion layer, which was found to be made of 86.8 at% Cu, 2.9 at% Ag, and 10.7 at% S. This composition corresponds to a mixture of copper and silver sulfides. Chemical analysis along the cross section of the whisker revealed that it was made of pure silver. Silver content changed drastically across the border between

the corrosion layer and the whiskers from ~3% in the corrosion layer to 100% in the whisker's body [14].

An important conclusion is that silver whiskers are mostly metallic formations; therefore they are highly conductive. Taking into consideration the rate of growth, the size and the amount of whiskers developing practically everywhere but mostly on the corners and edges of conductive parts, of the energized electrical equipment, it is obvious that the consequences of the phenomenon are extremely dangerous.

3.5.5 SILVER WHISKERS PUZZLE

The silver whisker phenomenon cannot be explained today no matter how much we know about the conditions in which these amazing “creatures” grow. The origin and the forces that initiate and support the growth of the whiskers are not yet defined. Not a single reliable reason has been suggested to explain why these filaments are growing on silver under suitable conditions. Perhaps one of this book's readers may find out what makes silver whiskers grow so intensely.

3.5.5.1 What Do We Know?

As was found, silver whiskers spontaneously grow on copper parts plated with silver, but may also grow on silver alloy or pure silver. Whiskers having silver metallic luster are made mostly of silver. When grown on plating they may contain up to 4% base metal copper. Whiskers with yellow metallic luster contain silver and 8–30% copper. It seems that in general the make-up of the whiskers and the conditions of growth are known. The presence of H_2S and elevated temperature seem to be two major accelerating factors of the growth.

3.5.5.2 What Do We Not Know or Understand?

It is not clear how to explain the following facts. Silver whiskers may grow from corroded silver coupon or from silver alloy. But more often they are found on silver-plated copper. The speed at which the whiskers grow reaches 1 mm/h. When growing on silver plating, metal filaments made of almost pure silver are growing from a corrosion layer made of silver and copper sulfides containing less than 3% silver. The original silver plating thickness is no more than 10 μm on copper substrate. The filaments are up to 10 cm long and 1 mm thick.

A simple calculation shows that to make just one silver whisker with such dimensions from silver contained in the layer of original plating with a thickness of 10 μm , the metal should be collected from the area of ~100 cm^2 . Moreover, in each location the whiskers grow in large tufts (see [Figure 3.5](#)) that are made of dozens of such filaments.

3.5.5.3 Questions Not Answered Yet

- What is the mechanism of growth of a 100% silver filament (single crystal?) from a corrosion layer made of CuS and Ag_2S ?
- What makes silver reduction from silver sulfide proceed so fast?
- What is the driving force that causes silver from a corroded 10 μm thick plating layer to be drawn into gigantic filaments of 1000 μm thickness and 100,000 μm length made of pure Ag?
- Where are all these amounts of silver coming from?

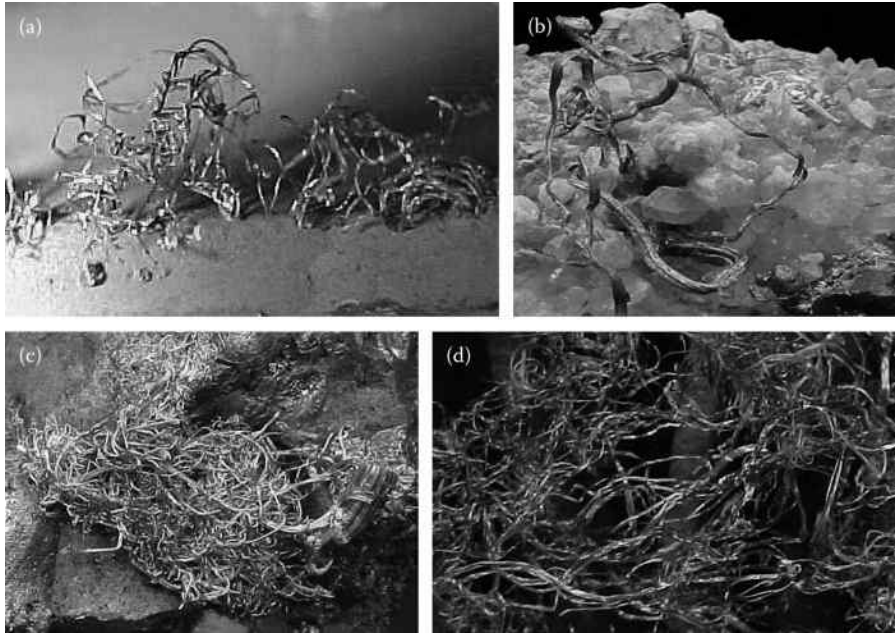


FIGURE 3.14 (See color insert.) Corrosion silver whiskers and natural silver wires (a, b, c, and d): is there a difference?

3.5.5.4 Native Silver Wires

In geology the phenomenon of whiskers growing on rocks is well known for many years. Many native whiskers have been found all over the world by geologists and miners. These unique growths are appreciated for their authentic beauty and unusual shapes and colors. They were found on rocks containing tiny amounts of precious metals (gold, silver) and also other metals. Many of the samples of these whiskers (called native wires) are offered for sale on the Internet. Surprisingly, the appearance of native silver wires is practically the same as that of silver whiskers shown in the pictures in this chapter. The major difference is in the age of the whiskers in these two groups. Look at Figure 3.14 and try to find out which of them matured for a couple of months in corroded electrical switchgear and which ones take centuries or millennia to grow on the rocks.

Is the silver whisker phenomenon the same as that observed in nature?

3.6 TIN PLATING CORROSION

Tin does not have great structural strength and so it finds most application as a coating for both ferrous and nonferrous substrates. Use is made of the corrosion resistance, soldering characteristics or ability to prevent galvanic corrosion effects between other metals. During atmospheric exposure, the presence of a substrate, exposed through pores in the coating, has little effect on the corrosion of tin.

Tin is often used as a plating for two metals widely used in the electrical industry: copper and aluminum. Although tin is considered resistant to atmospheric corrosion, there are several negative characteristics of tin plating, such as susceptibility to fretting corrosion, formation of intermetallics when plated on copper, low softening and melting temperature, and softness. These degrading tin properties are discussed in more detail in Chapters 1 and 2, including the formation of tin whiskers, one of the major failure (MF) causes of electric and electronic devices using tin as a plating or solder.

Tin plating withstands relatively harsh environmental conditions with corrosive gases pretty well. But tin reacts with different gases in the atmosphere forming various nonconductive compounds that may interfere with the electrical conductivity of tin plating [38,39].

Contact resistance is relatively stable for tin contacts in the atmosphere containing a mixture of SO_2 , NO_2 , and Cl_2 gases [39]. This is because relatively few corrosion products are formed on tin contacts. Also, the surface films formed on tin contacts shatter more easily upon plastic deformation. Corrosion experiments in atmospheres containing different combinations of SO_2 , NO_2 , and Cl_2 demonstrate that two types of corrosion processes take place in plated contacts. One is surface corrosion, which occurs when the surface finish is severely attacked by a corrosive atmosphere. The other is pore corrosion, which occurs when the underplating materials are attacked to a greater extent than surface corrosion. Both processes occur in tin contacts and the former is dominant in atmospheres containing Cl_2 .

3.6.1 TIN OXIDATION

Under most atmospheric exposure conditions, corrosion of tin depends on the formation and stability of an oxide film [38]. The thickness of a tin oxide film is shown to depend on the RH of the air. It was found that for samples with a starting thickness of tin oxide of 2 nm stored in a cupboard, the thickness of tin oxide film more than doubled to 4.5 nm in <45 days of observation, while for the samples stored in a desiccator, the oxide growth was much slower, reaching ~2.5 nm in 25 days of storage.

It was also shown that at room temperature an amorphous film is formed, while at higher temperatures it is apparently crystalline $\alpha\text{-SnO}$, possibly with some SnO_2 . The increase of the CR of tin coatings exposed to the atmosphere can be related to the growth of the oxide film on tin.

3.6.2 REACTION OF TIN WITH OTHER GASES

Under normal atmospheric conditions, H_2S and SO_2 have little effect on tin, but above 100°C , tin sulfide (SnS) is formed. High concentrations do, however, produce darkening or tarnish, while at low temperatures liquid or gaseous SO_2 may produce a crystalline solid with tin. The halogens attack tin readily at room temperature except for fluorine, which only reacts at a high rate above 100°C . Similarly, fumes from concentrated acids attack tin. Tin resists corrosion by the vapors of organic acids and other organic compounds such as might be emitted from wood or other packing materials.

3.7 ZINC PLATING CORROSION AND GALVANIZED STEEL

3.7.1 ATMOSPHERIC CORROSION OF Zn

Zinc is found in electrical equipment mostly on nonconductive parts, such as enclosures and hardware in the form of plating or as deposit on steel structures. Corrosion of zinc is possible when these parts are exposed to the atmosphere, either indoor or outdoor [40–42].

The behavior of zinc and zinc coatings during atmospheric exposure has been closely examined in multiple tests conducted throughout the world. The performance of zinc in a specific atmospheric environment can be predicted within reasonable limits. Precise comparison of the corrosion behavior in atmospheres is complex because of the many factors involved, such as the wind direction, the type and intensity of corrosive fumes, the amount of sea spray, and the relative periods of moisture or condensation and dryness.

However, it is generally accepted that the corrosion rate of zinc is low. It ranges from $0.13 \mu\text{m}/\text{year}$ in dry rural atmospheres to $0.013 \text{ mm}/\text{year}$ in more moist industrial atmospheres. Zinc is more corrosion resistant than steel in most natural atmospheres. For example, in seacoast atmospheres the corrosion rate of zinc is about $1/25$ that of steel. However, in ventilated indoor atmospheres the corrosion of both steel and zinc is extremely low.

Zinc is pretty resistant to atmospheric corrosion due to the formation of insoluble basic carbonate films. Environmental conditions that interfere with the formation of such films may attack zinc quite rapidly. Important factors that control the rate at which zinc corrodes in atmospheric exposures are: the duration and frequency of moisture, the rate at which the surface dries, and the extent of industrial pollution of the atmosphere.

In dry air, zinc is slowly attacked by atmospheric oxygen. A thin, dense layer of oxides is formed on the surface of the zinc, and outer layer then forms on top of it. The outer layer breaks away occasionally, but the underlayer remains and protects the metal, limiting its interaction with the oxygen. Under these conditions, which occur in some tropical climates, the zinc oxidizes very slowly. The rate of drying is also an important factor because a thin moisture film with higher oxygen concentration promotes corrosion.

The influence of multiple atmospheric factors, such as pollution, humidity, and temperature, on the corrosion of zinc is related to their effect on the initiation and growth of protective films. Zinc may be safely used in contact with most common gases at normal temperatures if water is absent, because moisture stimulates corrosion attack on zinc. Dry chlorine does not affect zinc. Hydrogen sulfide (H_2S) is also harmless because insoluble zinc sulfide (ZnS) is formed. On the other hand, SO_2 and chlorides have a corrosive action because water-soluble and hygroscopic salts are formed in a moist environment.

When used indoor, zinc corrodes very little in ordinary indoor atmospheres of moderate RH. In general, a tarnish film begins to form at spots where dust particles are present on the surface: the film then develops slowly. This attack may be a function of the percentage of RH at which the particles absorb moisture from the air.

Rapid corrosion can occur where the temperature decreases and where visible moisture that condenses on the metal dries slowly. This is related to the ease with which such thin moisture films maintain high oxygen content because of the small volume of water and large water/air interface area.

Studies of the corrosion of zinc when it was exposed to the atmosphere in the form of coatings on steel, either hot dipped or electroplated, indicated that there was less than a 10% difference between the corrosion rate of galvanized iron, zinc die castings, and three grades of rolled zinc. It was also found that the corrosion rate tended to be a linear function of time. In some instances, where the rate changed after a period of time, it was concluded that the amount of contamination in the atmosphere had changed.

Corrosion rates for zinc, like many other metals, can vary by as much as two orders of magnitude in atmospheric environments depending on the specific environmental conditions. Therefore, it is important to know the specific corrosion rate in a given application environment in order to effectively use zinc-coated steels in outdoor structures. For example, when compared with steel in the marine environment, corrosion attack on zinc where chloride deposition is important has low rates. Such an excellent resistance is attained by the hard, dense, protective products of corrosion in a chloride atmosphere. However, similar results cannot be achieved in a sulfurous atmosphere where the products are soft, voluminous, and nonprotective.

3.7.2 WHITE RUST ON ZINC

Zinc is a sacrificial barrier to protect the base steel. Zinc will sacrifice itself and eventually disappear before the base metal starts to corrode. Zinc plating protects the underlying steel by the formation of a “galvanic cell,” which results in the zinc corroding preferentially to steel. It is usually used as a functional indoor coating. By itself 5–8 μm of zinc plating will probably get no more than 12 h of salt spray protection per ASTM-B117. With a clear chromate top coat this is increased to 24–36 h, while a yellow chromate top coating (yellow zinc) can achieve protection up to approximately 96 h.

Where freshly galvanized steel is exposed to pure water (rain, dew, or condensation), the water will react with zinc and progressively consume the coating. Zinc is oxidized and changed to white rust (WR) that is a basic compound of zinc carbonate and zinc hydroxide; WR has white color and is also referred to in the literature as “wet storage staining.”

The most common condition in which WR occurs is with galvanized products that are stacked together, tightly packed, or when water can penetrate between the items and remain for extended periods. It is manifested as a bulky, white, powdery deposit that forms rapidly on the surface of the galvanized coating under certain conditions. The appearance of the corroded galvanized steel parts of a CB with white rust is shown in [Figure 3.15](#).

White rust causes considerable damage to zinc plating and is always detrimental to its anticorrosion function [43–45]. Different types of zinc plating have different levels of ability to resist the formation of white rust ([Table 3.1](#)).



FIGURE 3.15 White rust on corroded galvanized steel parts of a CB exposed to moisture.

TABLE 3.1
Approximate Hours to Formation of White Rust (WR) and Red Rust (RR) on Zinc Plating after Salt Spray (SS) Test

Type of Zinc Plating	Hours to WR	Hours to RR
Zinc	10	70
Zinc with clear chromate	75	200
Zinc with yellow chromate	100	250
Zinc–cobalt with yellow chromate	150	450
Zinc–cobalt with yellow chromate and post sealer	300	600

Source: Based on the data from ASTM B-117.

3.7.3 GALVANIZED STEEL

Galvanized steel is the most important application of zinc. One of the most popular methods of making steel resist corrosion is by alloying it with zinc. When steel is submerged in melted zinc, the chemical reaction permanently bonds the zinc to the steel through galvanizing. Coatings of metallic zinc are generally regarded as the most economical means of protecting steel against corrosion.

Seven methods of applying a zinc coating to iron and steel are in general use: hot dip galvanizing, continuous-line galvanizing, electro-galvanizing, zinc plating, mechanical plating, zinc spraying, and painting with zinc-bearing paints. Most of these are hot-dipped galvanized coatings containing a small amount of aluminum. The thickness of electroplated coatings is considerably lower than those applied by the hot dip process.

Galvanizing produces a zinc coating on the steel surface and is one of the most effective methods for corrosion protection of steel. This is attributed to the excellent corrosion resistance of zinc coatings, particularly in atmospheric environments. Zinc coating/plating processes are described in more detail in Chapter 1.

The most common method for estimating the corrosion life of galvanized steels uses a generalized value to represent the corrosion rates for five predetermined atmospheric environments as a function of zinc coating thickness. Service life is defined as the time to reach 5% rusting of the steel surface. It can be used to estimate the service life of a given coating thickness or to specify a coating for a given environment.

Corrosivity maps specify the thickness of galvanized coating required to achieve a useful life of 50 years in various environments. The method is applicable to zinc-coated steel produced by batch or continuous galvanizing, including hot-dip, electro-galvanized, and thermal sprayed coatings. However, it does not apply to coatings containing >1% of alloying elements. The method assumes that the galvanized product is free of significant defects that could accelerate corrosion. For example, the service life of a hot-dip galvanized Zn coating with a thickness of 40 μm is estimated to be ~30 years in an industrial environment, while it could last >50 years in a rural environment. However, the service life prediction does not consider issues of water entrapment that can create conditions for severe corrosion.

The galvanizing process prevents steel from corroding by providing cathodic, barrier, and patina protection [46].

- *Cathodic protection.* Zinc is more anodic than steel. Thus, when a corrosion cell forms—when both zinc and steel have an electrolyte and a return current path present—zinc readily gives up electrons that protect the steel from corrosion. Zinc will protect the base steel until all of the galvanized coating is consumed.
- *Barrier.* Zinc metal is very dense and thus does not allow moisture, or electrolytes, to penetrate the galvanized coating. Therefore, the base steel does not corrode.
- *Patina.* When exposed to the atmosphere immediately after the galvanizing process is complete, zinc metal reacts with oxygen in the air to form a very thin zinc oxide powder on the galvanized coating surface. After a few days the zinc oxide reacts with hydrogen in the air to form zinc hydroxide. As the zinc hydroxide is exposed to moisture in the air over a period of months, a thin film of zinc carbonate forms. Zinc carbonate is a passive patina film that is tightly bound to the remaining zinc of the galvanized coating and gives a hot-dip galvanized (HDG) coating its durability.

3.7.4 SIGNS OF GALVANIZED STEEL CORROSION

Galvanized steel corrosion is usually easily recognized in the presence of rust and pits. The same signatures reveal the corrosion of other types of steel/iron parts.

3.7.4.1 Rusting

Corrosion of steel is easily recognized because the corrosion product is red rust (RR). As soon as a protective layer of zinc plating on and around steel parts is destroyed and converted into porous white rust, there is no more barrier between steel and oxidizing agents of the atmosphere, which reacts with iron to form rust on the surface of steel parts. When iron base alloys corrode, dark corrosion products usually form first on the surface of the metal.

If moisture is present, this ferrous oxide coating is converted into hydrated ferric oxide, which is known as red rust. This material will promote further attack by absorbing moisture from the air. The shade of iron oxides ranges from a dull yellow through various oranges and reds to a deep black. Red rust (Fe_2O_3) and black rust (Fe_3O_4) are usually mixed together and the color of corrosion deposit may be different in shade depending on which oxide in the mixture is present in a larger amount.

When an electrical unit such a CB is exposed to moisture, the protective zinc plating corrodes and degrades, leaving the base metal (steel) exposed to corrosion as well. Extensive rusting of the parts made of steel (bolts, fasteners, mounting plates, and laminated arms) then develops.

3.7.4.2 Pitting Corrosion

Pitting is a form of extremely localized corrosion that leads to the creation of small holes in the metal. The driving power for pitting corrosion is the lack of oxygen around a small area. This area becomes anodic while the area with excess of oxygen becomes cathodic, leading to very localized galvanic corrosion. The corrosion penetrates the mass of the metal, with limited diffusion of ions, further pronouncing the localized lack of oxygen. Pitting can be initiated by a small surface defect, being a scratch or a local change in composition, or damage to protective coating. Polished surfaces display higher resistance to pitting. An example of pitting corrosion on galvanized steel parts is shown in Figure 3.16.

The alloys most susceptible to pitting corrosion are usually the ones where corrosion resistance is caused by a passivation layer. Regular carbon steel will corrode uniformly in sea water, while stainless steel will pit. All stainless steels can be considered susceptible to pitting, but their resistances vary widely. Their resistance to attack is largely a measure of their content of chromium, molybdenum, and nitrogen. The addition of about 2% molybdenum increases pitting resistance of stainless steel.

Another important factor is the presence of certain metallurgical phases (in particular, the grades 303, 416, and 430F of steel containing inclusions of manganese



FIGURE 3.16 (See color insert.) Pitting corrosion on galvanized steel.

sulfide) which have very low pitting resistances, and ferrite may be harmful at austenitic grades in harsh environments. A clean and smooth surface finish improves the resistance to attack.

3.7.5 FACTORS AFFECTING GALVANIZED STEEL CORROSION

Several factors may accelerate the rate of galvanized steel corrosion.

3.7.5.1 The Environment

The areas near the ocean coast might be influenced by multiple environmental parameters (airborne salinity, meteorological systems, hydrochemical parameters). These factors might have a strong effect on the corrosion of mild steel, which is the material that the nonconductive parts of electrical equipment, such as circuit breakers, are often made of. It is a well-known fact that corrosion of steel on a sea coast is 400–500 times greater than it is in a desert. The closer to the coast line the equipment is located, the higher the corrosion rate is. Steel specimens located 80 ft from a coast corroded 12 times faster than specimens located 800 ft away from a coast. Salt is the chief contaminant. Black rust, found in the pits on the surface of corroded steel plates, is more often formed in saline environments with limited access to oxygen.

3.7.5.2 Thickness of Zinc Plating

A factor that could increase the rate of zinc plating deterioration exposed to wet conditions is the thickness of the plating. The rate of corrosion for zinc plating depends on the atmosphere to which the plating is exposed. ASTM standards specify different minimum zinc plating thicknesses according to the severity of different atmospheric conditions determined by the corrosion rate (see Table 3.2). According to the ASTM standards, if zinc plating had not been initially exposed to wet conditions and then installed indoors, it will take about 10 years to completely deteriorate even the thinnest plating specified (5 μm).

TABLE 3.2
Mean Corrosion Rates for Zinc Plating and Thicknesses of Zinc Plating for Different Atmospheric Conditions

Atmosphere	Mean Corrosion Rate (μ /per year)	Condition	Minimum Plating (μ)
Industrial	5.6	Mild dry indoor	5
Urban nonindustrial	1.5	Moderate corrosive	8
Suburban	1.3	Severe corrosive and outdoors	12
Rural	0.8	Exceptionally severe—marine	25
Indoors	<<0.5		

Source: Based on the data from ASTM B695-85 and ASTM-B633.

However, if plating was wetted and the formation of white rust had started to develop, it will be only a matter of time how soon it will be all consumed. The deterioration begins when a localized corrosion cell is formed. The activity of such corrosion cell (pit) results in rapid penetration through the zinc coating to the steel. It will take somewhat longer for converting zinc plating into white rust for thicker plating, but as soon as the WR is formed there are no more barriers for oxidizing agents to penetrate through “white rust” to the surface of steel.

3.7.6 CORROSION OF GALVANIZED STEEL IN CIRCUIT BREAKER

Many parts of power CBs are made of galvanized steel. Corrosion of galvanized steel may lead to the failure of electrical equipment exposed to excessive moisture. In this example the parts of an MV CB were found to be severely corroded after 2 years of previous refurbishment. Signs of corrosion have been found on plated steel parts, such as bolts, washers, mounting plates, laminated arms, and so on. The parts with corrosion

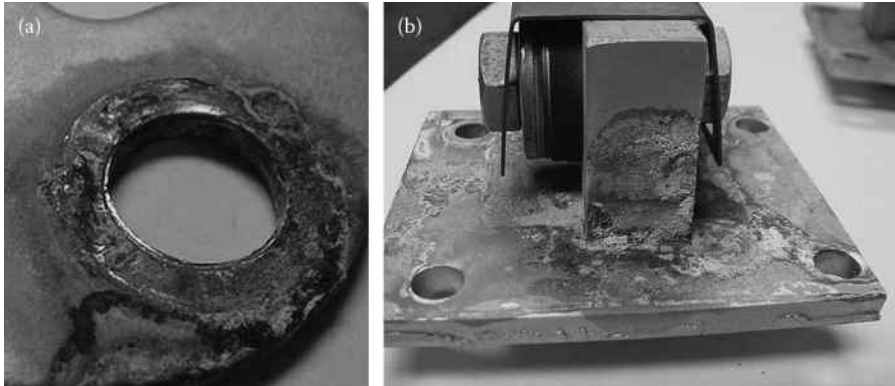


FIGURE 3.17 (See color insert.) White rust and red rust on the mounting plates (a) and around the opening in steel plates (b).

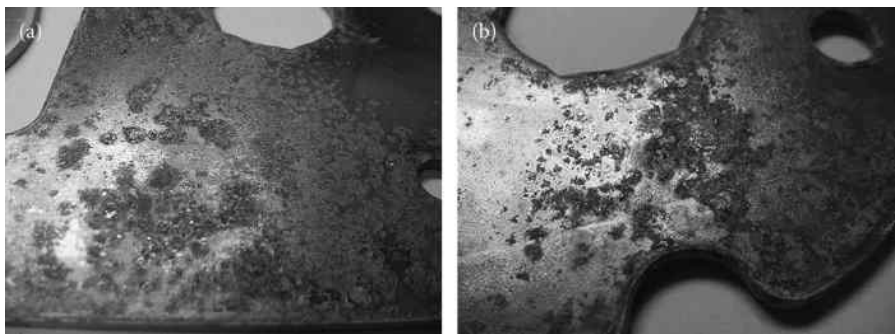


FIGURE 3.18 (See color insert.) Pitting corrosion found on the surfaces of steel parts: black and brown pits (a) and green pits (b).

spots are shown in [Figures 3.17](#) and [3.18](#). To determine the root cause of corrosion it is very important to carefully examine the parts and locate all signs of corrosion.

According to the reconditioning program all steel parts have been zinc-plated, although the type of zinc plating is rarely predetermined in reconditioning procedures. The color of the parts of the corroded breaker allows defining the type of plating. For example, bronze–gold or light gold color is specific for yellow zinc (Zn chromate) plating.

Three major types of defects have been found: white deposits on the surfaces, dark pits on the plates of laminated arms, and brown corrosion product on plates and fasteners. The most extensive brown corrosion or red rust specific to the corrosion of iron is observed on mounting plates, bolts, and washers made of steel ([Figure 3.17](#)).

In the close vicinity of brown spots and pits on all the parts where steel is rusted, a white deposit is present, which means that Zn plating has been corroded, forming white rust, leaving the base metal of the parts(steel) unprotected from corrosion by Zn plating and exposed to air and water. Without this protection, not only “red rust” is produced, but also the pitting corrosion develops at random in the pits on the surfaces of the parts.

On CB parts the pitting corrosion is mostly found on those plates of the laminated arms that are tightly stacked together ([Figure 3.18](#)). It can be explained by the moisture condensed between the plates, where it accumulates and does not dry out for long periods of time (the so-called “sheltered” corrosion).

The color of pits is different in different spots: black, dark brown, and light brown ([Figure 3.18a](#)). Most probably, the corrosion products in the pits consist of a mixture of different iron oxides. Pitting usually occurs under certain conditions, particularly involving high concentrations of chlorides (such as sodium chloride (NaCl) in sea water), moderately high temperatures and also the presence of neutral or acidic solutions containing other chlorides or halides. This explains why the color of some pits has a greenish hue to it ([Figure 3.18b](#)), which might be due to the admixture of FeCl_2 in some spots.

Since the facility where the breaker has been installed was located near the sea coast, environmental factors such as elevated air airborne salinity and humidity could play a destructive role in severe corrosion of steel and lead to failure of the CB.

3.8 MEANS OF CORROSION PROTECTION OF ELECTRICAL EQUIPMENT

3.8.1 PROTECTIVE COATINGS FOR CONDUCTIVE PARTS, ENCLOSURES, AND FRAMES

3.8.1.1 Metallic Coatings for Conductive Parts and Enclosures

Metallic coating is usually used to protect the base metal from corrosion. As protective coatings, a distinction must be made between those such as zinc, cadmium, and aluminum on steel that protect by sacrificial behavior and those that must provide a substantially continuous protective envelope around the protected metal. In the latter category are metals such as nickel, tin, silver, brass, and chromium.

Sacrificial metals corrode as coatings in much the same manner as solid metals do until the base or protected metal is exposed at pores or bare areas. Then the galvanic corrosion action begins to accelerate the corrosion of the protective coating. This galvanic couple effect tends to protect the base metal at the pores or bare spots. This reaction is different from what happens in the case of the more noble protective coatings that act as a cover and resist the atmosphere due to their inertness, passivity, or protective films. As soon as a pore or bare spot appears, the corrosion of the base metal is accelerated. Die castings of a metal such as zinc covered with a copper–nickel–chromium coating will suffer severe corrosion at large pores or discontinuities in the coating.

Some metal coatings are applied by electroplating, while the others are produced by flame or plasma spraying, hot dipping, electrostatic sputtering, or vapor deposition. The corrosion rate of a metal coating is largely independent of the method of application, except where impurities play a role. In noble types of coating, porosity of metal coatings is very important, because it affects mechanical, electrical, and anticorrosion properties of the plating. There are many factors that influence a coating porosity, but among them, the most important factor reducing porosity seems to be the thickness of electrodeposited coating. Porosity tends to decrease rapidly (by exponential law) as the coating thickness increases.

Tin and tin alloys tend to be inert in the atmosphere unless any specific type of contamination exists. As far as exposure to the atmosphere is concerned, tin appears as a coating on steel containers but it can accelerate the corrosion of the more anodic steel by pitting. Due to their inertness, silver and gold are used as alloys to improve corrosion resistance of the more reactive metals. Corrosion of tin and silver is discussed in more detail in the following sections.

3.8.1.2 Polymeric Coatings and Paints for Enclosures and Frames

The exterior surfaces of electrical equipment, such as enclosures and frames, if not metal plated, are protected from the environment by applying paints or polymeric coatings. To protect steel enclosures from corrosive solvents, fumes and gases, various powder coatings (Polyester, Epoxy) and polyurethane paint are used. Detailed information about the polymeric coatings used in the electrical industry is given in Section 5.7.

Paints and coatings are designed to provide a long-lasting barrier between the metallic material they cover and the atmosphere. Various criteria and their order of importance have been established when selecting the best coating for enclosure, which basically perform two functions: protection and decoration.

However, essentially all polymers exposed to environmental factors will change in some manner. The active rays of the sun become potent agents of change in organic materials. Further polymerization of the resin can occur to produce embrittlement. Other types of bonding can be triggered to make polymers more crystalline. Any volatile component of the material, such as a plasticizer, can be evaporated. The polymer chains may be simply oxidized and broken up to destroy the product. Oxygen, ozone, and moisture act with the sunlight to degrade the plastics.

The external evidence for attack may be blushing (loss of gloss), chalking, or change in the color of the product. This is often observed on the epoxy and polyester polymers when they have been boldly exposed to the environment. However, only mechanical tests will reveal the extent of degradation of either thermoplastic or thermosetting resins.

The effect of high atmospheric temperatures or heating from a direct exposure to the sun can be particularly strong on thermoplastic polymers. Creep or distension of the polyvinyl chloride (PVC) and polyethylene (PE) plastics will occur readily unless provision is made to prevent overheating or stressing of the materials. Other thermoplastics can be dimensionally stable under normal atmospheric temperatures. The strength of these thermosetting resins is not noticeably changed.

Polymeric materials should be thoroughly tested if they are to be exposed to the atmosphere. ASTM Recommended Practice D1435 describes the appropriate conditions for such a test exposure and suggests tests that might be used to evaluate changes in the materials. Changes in the mechanical and physical properties of the polymers are determined for definite results. Weight gains or losses can be of interest, but do not provide substantive results.

Accelerated cabinet testing of the materials can be performed with essentially the same validity as when testing metallic materials. Poor materials can be eliminated, but extrapolation of the data to forecast the life of plastic parts in the atmosphere should not be attempted. ASTM D1499, D 2565, and G26 may be used to ensure the controlled cabinet testing of the plastics. ASTM D750 should be used for the evaluation of the elastomers.

3.8.2 MEANS OF PROTECTION FROM SILVER CORROSION

There are several ways to protect metals from corrosion which would be applicable to various materials exposed to different corrosive atmospheres.

3.8.2.1 Silver Protection from Corrosion

Any developed anti-tarnishing methods will only delay silver corrosion but cannot eliminate it. None of these methods satisfy all applications. The most important requirement for any type of silver plating treatment used in the electrical industry is to not affect the electrical resistance. Various methods useful in decorative applications such as the application of various protective films such as lacquers, oils, and inorganic deposits such as metal oxides on silver plating [47] cannot be utilized for electrical contacts. The application of electrolytic silver alloy deposits and composite coatings is another type of antitarnishing technique that is often used for luxury jewelry items but that cannot be used here due to high electrical resistance of these deposits. The most frequently used antitarnishing technique in the electric and the electronic industry is metal coating applied by immersion or electrochemically.

3.8.2.2 Silver Plating Thickness

The role of silver plating thickness in the corrosion process might be very important. It was shown [20] that when the silver coating thickness increases, the total corrosion

film thickness decreases and the corrosion film contains less copper. First, these changes lead to a dramatic decrease in CR. Secondly, the build-up of silver sulfide thick enough to start the growth of the whiskers might be significantly slowed down. Therefore, the thickness of silver coating is a very important factor in the reliability of contacts in environments that are corrosive for both silver and copper. The copper creep corrosion film is thought to be detrimental to silver-plated contacts, mainly due to a higher growth rate in comparison with silver corrosion films. Thick pore-free silver coating with a thickness of about 20 μm is recommended to prevent the influence of the copper substrate on the corrosion mechanism.

3.8.2.3 Alternate Plating

Corrosion-induced growth of the filaments on metals other than silver has not yet been seen. Therefore, the use of other than silver plating may eliminate the silver whisker problem. Substituting silver with expensive gold plating might not be a good solution. There are difficulties with this strategy, since many control switches and protective relays are not available with gold-plated contacts. Tin plating has other problems, such as a much higher resistance than silver, galling, and softness; these make it less than ideal for sliding contact applications. However, in Ref. [31], it was recommended that tin plating instead of silver be used in electrical equipment for the paper industry, in current-carrying parts of contactors and breakers, and in the stabs and stab mating fingers, everywhere except arcing contacts.

When choosing tin for plating in a very aggressive atmosphere it is useful to follow the “Tin Commandments” developed by Whitley [48]. It is considered to be poor practice to use pure tin plating on contacts because of whiskers, which develop on the surface no matter whether there is atmosphere or vacuum. The use of tin alloys with 5% or less of lead or other tin alloys was suggested as a practical solution to the whisker problems [49]. However, the introduction of the RoHS initiative limited the use of lead for most applications of tin plating. The problems that arise due to tin whiskers growth and other tin plating issues are described in Sections 1.5 and 2.1.

3.8.3 CONVERSION TREATMENT

The purpose of a conversion treatment (passivation or antitarnishing treatment) is to delay the appearance of tarnishing. Conversion coating is a generic term for any process that converts the surface of a part into a coating. For example, chromating is an immersion process in which metal parts are immersed in a solution containing chromates and other chemicals. The purpose of this process is to convert the surface into a thin film that enhances the corrosion resistance. In this process, Chromium VI is present in solution and if this treatment is applied, CrIV will be present in tarnishing and passivation layers on silver coatings.

Recently, there has come a rule that a conversion treatment should comply with the requirements of the European directive 2002/95/CE (RoHS directive [50]) of the European Parliament and the European Union Council of January 27, 2003. This directive restricts the presence of hazardous substances in electric and electronic equipment, and hexavalent chromium (Chromium VI) is one among them. RoHS principles and reach are global. The directive indicates that anything covered by

RoHS entering the European Union (EU) must be in compliance; this includes cables made in China, parts molded in the United States and PCBs made in Japan. If it is destined for the EU, it is impacted by RoHS. And it is not just the EU that is taking steps to reduce the toxins in electronic devices, California's Electronics Waste Recycling act of 2003 (SB 20, Chapter 526) echoes the RoHS directive and was supposed to take effect on January 1, 2007.

3.8.4 CHROMIUM-FREE VARNISH-PREVENTATIVE PROCESSES

Antitarnish processes without heavy metal ions are designed to add value to silver and silver-plated substrates by preserving the as-plated appearance and minimizing tarnishing of the surface. The parts are immersed into a liquid concentrate, which after treatment leaves a thin, invisible organic film on the plated surfaces that in general has no influence on the surface resistance of electrical contacts.

This protection works only for 6–12 months; therefore it would be a suitable treatment to protect electrical contacts from tarnishing in storage. In service protection of the surfaces will be only temporary; it will not prevent corrosion in the long run. According to technical specifications, some solutions seem appropriate for use in electrical applications. However, since some chemicals provide a top coat (or sealer) on the parts, for specific applications they should be tested to prove that film application does not deteriorate the electric continuity.

3.8.5 MEANS OF PREVENTING THE CORROSION OF ZINC-PLATED STEEL PARTS IN ELECTRICAL EQUIPMENT

Corrosion of galvanized steel in electrical equipment is often the result of exposure of the components to moisture, which causes zinc plating oxidation and formation of porous white deposit on the parts (white rust). A premature, rapid loss of galvanized zinc coating on steel surfaces results in the corrosion of the underlying steel. The most probable root cause of the rusting of the galvanized steel parts is an exposure of electrical equipment to wet conditions: rain, dew, or condensation.

For those equipment that are usually installed indoors, such as CBs, water could get inside the breakers during the period between shipment and installment. The possibility of moisture getting inside such equipment depends on how the units have been packed for shipment and how long and where they have been stored at the customer facility before being installed.

White rust is a postgalvanizing phenomenon. One way to prevent rust is by checking the manner in which the unit is packed, handled and stored before it is installed and used. The presence of WR is not a sign of the galvanized coating's performance, but rather points to the responsibility of all those involved in the supply chain to ensure that the causes of WR are recognized and the risks of its occurrence minimized on zinc-plated steel.

Every precaution should be taken to prevent electrical apparatus from becoming and remaining wet. During shipping, the unit should be protected to ensure that no water intrusion takes place even when it rains while shipping. Plastic wrapping with tarp could be a solution to prevent water from getting inside the unit, but the

wrapping should not be too tight in order to allow the unit to “breathe” by air circulation. If it does get wet, it should be stored in such a manner that it is allowed to dry. The customer should not allow zinc-plated apparatus to be exposed to water or dampness for extended periods of time after receiving the unit. The zinc-plated apparatus should be stored in a warm, dry environment. The unit should not be removed from the cover until it has reached room temperature.

3.8.6 VAPORIZED CORROSION INHIBITORS

Vaporized corrosion inhibitors (VCI) [51–54] may be used for the temporary protection of silver plating. VCI are widely available in the market; these compounds do not have a significant effect on the electrical contact resistance (CR). VCI emitters can be placed within electrical enclosures to retard internal corrosion, as long as the air exchange with the outside environment is limited. They release a chemical vapor into the enclosed still air space, to form a protective invisible molecular film settling on the metal surfaces as a barrier layer that limits excess of corrosive gases to the plating surface.

A full range of corrosion inhibitors has been developed to protect ferrous and nonferrous metals, including formulations that protect combinations of metals. Providing protection for 1–2 years, each such container is effective within an area of up to 1.8 meters (6 ft) in radius. Similar vapor-releasing compounds are also available as tapes or spray-can formulations for use on surfaces in the open air.

For storing apparatus or components, according to the environment of exposure, a special packing containing volatile corrosion inhibitors could be used that would protect the material during transport and storage. Several effective VCI products are widely available in the market. Vapor corrosion inhibitors may slow down the corrosion of silver-plated copper parts in switchgear in atmospheres containing over 200 ppm of mixed gases such as SO_2 , H_2S , HCl , and so on.

There is a temperature limit for using this technique, since the higher the temperature is, the faster the VCI evaporates. At an operating temperature of 120–140°F the useful lifetime will start decreasing, and if they are used continuously at elevated temperature, containers emitting VCI should be replaced more often than once every 2 years.

3.8.7 LUBRICATION

Sealing out corrosive gases with lubricants can help to protect metal surfaces against atmospheric corrosion. The use of lubricants is widely accepted as an effective means of protecting silver-plated contacts from corrosion [55]. However, for many years, the benefits of using lubricants for corrosion inhibition were overlooked because prospective users were skeptical that a nonconductive substance could be applied to contacts without interfering with the conduction.

The choice of the lubricant for corrosion protection should be based on the thorough evaluation of the product for survival in long-term use and the ability of such products to provide friction and wear reduction. Corrosion inhibitors/lubricants applied at any sliding contact points and surfaces will do this job very well. Special

attention should be given to the correct choice of these products to not induce interference with the electrical properties of conductive parts. An effective lubricant for electrical parts should be chemically inert towards the metal surfaces to be lubricated.

Lubricants used on silver-plated surfaces should not carry sulfur-containing compounds. Lubricants for electrical parts should not collect dust and particulate matter and should be resistant to oxidation and chemically inert to corrosive atmospheric components. These lubricants should not build nonconductive deposits on contact surfaces after multiple operations and retain long-term thermal stability at least up to 200°C (~390°F). Any corrosion inhibitor must be thoroughly tested for electrical application. In fact, very few lubricants have been identified that provide exceptional long-term corrosion protection and yet do not produce any adverse effect on connector surfaces. An example of a lubricant that proved useful for corrosion protection for connectors made or plated with precious metals is six-ring polyphenyl ether (PPE) or its mixture with microcrystalline wax, although the wax content should be controlled.

Multiple products such as greases with a synthetic soap thickener and other commercial products have been tested and proven useful for bolted contact application. These issues will be presented in more detail in Chapter 4.

3.9 MEANS OF ENVIRONMENTAL CONTROL FOR CORROSION PROTECTION

3.9.1 ASSESSMENT OF ELECTRICAL AND ELECTRONIC EQUIPMENT EXPOSURE TO CORROSIVE ENVIRONMENT

Electrical equipment is exposed to the corrosive environment of many industrial facilities, including pulp and paper mills, chemical plants, oil refineries, and so on. In electrical power systems, the build-up of corrosion products can cause overheating, leading to reduced equipment life or even to explosions of CBs and motor starters. While the cost of the systems themselves are high, the production losses from moderately sized operations can quickly add up to exceed the costs of repairing or replacing the affected systems.

Corrosive failure of electronic equipment is particularly common in the pulp and paper industries. Low concentrations, in the ppb range, of gaseous contaminants such as H_2S , SO_2 , NO_x , Cl_2 , mercaptans, or NH_3 in air coming in contact with electrical switching circuits will quickly react with most metals, forming nonconducting layers of metal salts. As a result, substantial resistance to current flow develops, variations in voltages occur, and the entire circuit may become useless due to changes in component value.

There are many different kinds of failures in electronic process control equipment that are induced by corrosion. The failure could be due to the braking of corroded copper wires, caused by the acid condensates trapped under the insulation.

Electrical contacts could fail due to corrosion product creep following galvanic corrosion between precious metal plating and substrates, for example, between gold and copper or nickel. Gold, which does not react with the environment, is used as plating on base metal substrates, such as copper and nickel, which react with the environment.

Corrosion can occur where the gold plating is porous, and the rate of attack is accelerated when the humidity is high. Corrosion products creep over the gold-plated surface, resulting in high electrical CR and a functional loss of electrical contact. Corrosion product creep is a rapid process, and in a simulated sulfur-containing environment, gold-plated surfaces were substantially covered with corrosion products in a few weeks [56].

Chemical substances found in paper mill environments, which are corrosive to electronic equipment and materials, may be gaseous or solid. The principal gaseous corrosives are the following: hydrogen sulfide, sulfur dioxide, the acid chlorine gases, and water vapor. Water vapor, sulfur dioxide and hydrogen sulfide influence the rate of both copper and silver corrosion.

The results of experiments conducted at 86 control rooms in a single bleached Kraft mill to predict failure rates based on the atmospheric corrosivity are presented in Refs. [57,58]. The atmospheric corrosivity in each of the 86 electrical rooms in the mill was measured during a 90-day period, using the coupon monitoring procedure [56]. Corrosion-related failure histories of control equipment in these rooms were obtained from the electrical maintenance staff.

According to Refs. [57,58], to eliminate premature corrosion failures in control rooms containing only electrical equipment (and no electronic equipment), the atmosphere must produce $<0.5 \mu\text{m}/\text{year}$ of corrosion product on the copper coupons. Electrical contacts and wires will fail in about 3 years if corrosion deposits are thicker than $0.5 \mu\text{m}/\text{year}$.

To eliminate premature failures of electronic equipment, the control room atmosphere must produce much less than $0.2 \mu\text{m}/\text{year}$ of corrosion product on the copper coupons. The circuit boards may fail in 3–4 years, but they may fail much sooner (in 2 years) if the layer of deposit forming on copper is thicker than $0.76 \mu\text{m}/\text{year}$, and in 1 year if the corrosion layer is $>1.3 \mu\text{m}/\text{year}$. A limit of $0.1 \mu\text{m}/\text{year}$ was chosen as a practical maximum thickness of corrosion product to safeguard electronic equipment.

In addition to corrosive gases, particulates in the environment may contribute to the corrosion. Hygroscopic dirt, such as sodium sulfate dust in a pulp mill chemical recovery area, attracts moisture and forms a corrosive solution. This can pose problems if the hygroscopic dirt becomes lodged between two conductors so as to attack one of them or cause a short circuit.

3.9.2 AIR QUALITY MONITORING

Most of the world's leading manufacturers of computer systems recognize the severity of the corrosion problem at industrial facilities. In many countries the industrial standards define the acceptable levels of airborne contaminants and provide achievable and effective guidelines to protect electronics and electrical equipment from the damaging effects of corrosive gases.

The first line of defense against corrosion is an air monitoring program in the industrial facility, when a choice between an active and a passive air condition monitoring and between direct versus indirect monitoring techniques should be made.

For environmental corrosion assessment, the ideal situation would be continuous, on-line, multiple gas monitoring; however, this is usually an expensive solution. To

continuously measure the ambient concentrations, which are typically quite low, and to monitor different combinations of gases, which produce varying reactivity levels, many different diagnostic methods have been developed. Reactivity monitoring can characterize the destructive potential of an environment. The growth of various corrosion films on specially prepared copper and silver coupons provides an excellent indication of the corrosion types.

Air monitoring is central to any environmental control program for achieving and maintaining air quality standards based on the presence (or absence) of gaseous air pollutants. Such a monitoring can also provide the short-term data required to manage and mitigate contaminant-specific episodes.

Several characteristics of any measurement technique must be evaluated to determine its suitability for use in air quality monitoring [59]. Among the more important characteristics are sensitivity, cost, and complexity. Sensitivity is a particularly demanding parameter for environments where near-ambient levels of many pollutants may be encountered and control levels are in the low ppb range. When deciding on a measurement technique, particularly in large surveys, the cost may be quite important. It is also important to consider the complexity of the technique and the degree of skill and training required to obtain quality results.

Other factors deserving consideration are selectivity and portability. Most measurement techniques are not optimized for all these parameters, and it is very important to evaluate the various characteristics and techniques of the monitoring system in order to achieve best results in monitoring the air quality at the industrial facility.

3.9.3 DIRECT GAS MONITORING

Electronic devices designed for real-time gas monitoring respond to changes in the measured variable very quickly. They are capable of detecting pollutant levels in the low ppb range, and are available for a wide range of pollutants.

Individually, chemical pollutants may be monitored using various analytical techniques to provide both the sensitivities and selectivities required for accurate low-level real-time monitoring.

The major disadvantage of the use of real-time gas monitors is the relatively high cost when compared to other techniques. [Table 3.3](#) lists a number of different pollutants and the levels which can be monitored with real-time monitors [59].

3.9.4 CORROSION CONTROL TECHNOLOGY

The three methods of gaseous contaminant control most commonly employed in HVAC (heating, ventilation, and air conditioning) systems are source control, ventilation control, and removal control.

Source control should always be the first strategy examined. Removing the sources of contaminants prevents them from becoming a problem in the first place. However, in the industrial environments, the source of gaseous contaminants is the manufacturing processes themselves and cannot be easily removed. With many process technologies significantly improved, the emissions have been reduced over the

TABLE 3.3
Available Real-Time Chemical/Gas Monitors

Pollutant	Concentration Range (ppb)	Lower Detection Limit (ppb)	Response Time (s)	Selectivity	Susceptibility to Interferences
Ammonia	0–200	1.0	900	Medium	Low
Formaldehyde	0–1000	0.2	300	High	Low
Hydrochloric acid	0–200	1.0	900	Medium	High
Hydrogen sulfide	0–200	1.0	120	Medium	Low
Nitrogen oxides	0–200	0.1	90	NO-High NO ₂ -Low	Low
Ozone	0–1500	1.0	50	High	Low
Sulfur dioxide	0–200	0.1	120	High	Low
TVOC	0–20,000	20.0	120	Low	Low

Source: From Christopher O. Muller, Control of Corrosive Gases to Avoid Electrical Equipment Failure, Online. Available: http://www.purafil.com/Literature/Control_of_Corrosive_Gases_to_Avoid_Electrical_Equipment_Failure.pdf. With permission.

last several years, but they are still a long way from levels that would be considered safe for electronic equipment.

In some situations, the source control is not an option. Then ventilation control should be the next option. Ventilation control involves the introduction of clean dilution air into the affected space, which allows reducing contaminant levels below acceptable threshold levels. Unfortunately, in some industries, such as pulp and paper mills, the outside air does not meet the required criteria with regard to gaseous contaminants as well. Therefore, if this air would be used for ventilation, it will simply increase the total level of contaminants at the facility.

It is clear that when neither source nor ventilation control is available to control the levels of gaseous contaminants in the affected space, removal control should be employed. Removal control may be provided by special gas-phase air filtration systems employing one or more dry-scrubbing media as an integral part of the HVAC system, which can effectively reduce gaseous contaminants to well below standard levels.

There are three types of airborne contaminants that need to be controlled [60]: liquids, solids, and gases. To deal with low-level airborne liquids and solid contamination, particle removal filtration, such as mechanical filters, is used. The most common technology available for removing gaseous contaminants is gas-phase, or dry-scrubbing, filtration.

Air filtration can effectively remove essentially all of the gaseous contaminants that could negatively impact electrical systems when proper considerations are made in choosing the gas-phase (chemical) filters. A typical gas-phase air filtration device has three major sections. The first section would consist of a one- or two-stage particulate prefilter to remove dust and other particulate matter that could “coat” the chemical filter media. The next section consists of 2–3 stages of the appropriate chemical filtration media, which would be followed by a final filter section.

3.9.5 CHEMICAL AND PARTICULATE FILTRATION

Electronic process control equipment can be protected from corrosion in several ways. One way is to clean the air in the control room of corrosive gases or to keep corrosive gases out of the environment of the control room. The second option is to place the control equipment in an airtight cabinet and use vapor corrosion inhibitors (VCI). The third way is to use more resistant but substantially more expensive materials for building the control equipment.

The first option might be most practical and affordable. To keep corrosive gases out of the control room environments through the use of a modular filtration system using a deep bed of specialty activated carbon may be a valuable solution for the corrosive problem. This system works on the principle of supplying a purified air stream to pressurize the enclosed area to minimize the possibility of corrosive gas intrusion into the control room.

Air conditioning could be much more effective if fitted with activated carbon filters, which are housed in a separate box approximately the size of one of the air conditioning units. This method may effectively remove corrosive gases such as hydrogen sulfide, sulfur oxides, chlorine and chlorine compounds. Solid particulates, primarily sodium sulfate and sodium carbonate, are removed by appropriate mechanical filters.

In order to meet removal requirements and to minimize installation costs, a skid-mounted, modular filtration system may be used. A carbon adsorber using a deep carbon bed of a specialty carbon may help to achieve a high degree of make-up air purity for a protection period of at least 1 year for most expected mill conditions.

3.9.6 TEMPERATURE CONTROL

In many cases, corrosion is accelerated in the environment with elevated temperature; therefore temperature control is essential for corrosion control. There are two major factors causing overheating. For example, when silver is exposed to a sulfuric environment, it forms a nonconductive silver sulfide deposit, resulting in a highly resistant contact surface. With the increase in resistance, more heat is generated, speeding up the chemical reaction of silver with H_2S , which finally leads to thermal connection failure.

The second factor is the deterioration of the mechanical integrity of the components. It is very important to timely maintain the mechanism to keep the contact pressure at critical points, such as between the stab and the fingers, at the desired level. Otherwise as the pressure decreases, the resistance will increase and, depending on the current, more heat will be generated.

As follows from the literature review and observations (Section 3.5), an elevated temperature of the electrical equipment is one of the factors that accelerate the process of silver corrosion and whisker growth in particular. If the temperature of the electrical parts could be maintained at a relatively low level (below the standard maximum operating temperature of $\sim 105^\circ\text{C}$) in the facilities contaminated with H_2S , the rate of silver corrosion and silver whiskers growth may decrease significantly.

To keep the temperature at a safe level, it is helpful to use one of available means of monitoring the temperature of the energized equipment. The techniques for such monitoring on-line will be described in Chapter 7.

3.10 CORROSION GLOSSARY

A

Acid: A substance which releases hydrogen ions when dissolved in water. Most acids will dissolve the common metals and will react with a base to form a neutral salt and water.

Acid rain: Atmospheric precipitation with a pH between 3.6 and 5.7. Burning of fossil fuels for heat and power is a major factor in the generation of oxides of nitrogen and sulfur, which are converted into nitric and sulfuric acids washed down in the rain. See also Atmospheric corrosion.

Acidity: The quantitative capacity of water or a water solution to neutralize an alkali or base. It is usually measured by titration with a standard solution of sodium hydroxide and expressed in terms of its calcium carbonate equivalent.

Activity: A measure of the chemical potential of a substance, where chemical potential is not equal to concentration, which allows mathematical relations equivalent to those for ideal systems to be used to correlate changes in an experimentally measured quantity with changes in chemical potential.

Adhesion: A binding force that holds together molecules of substances whose surfaces are in contact or near proximity. The ability of dry paint to attach to and remain fixed on the surface without blistering, flaking, cracking, or being removed by tape.

Adsorb: To take in on the surface.

Adsorbent: A material, usually solid, capable of holding gases, liquids and/or suspended matter at its surface and in exposed pores. Activated carbon is a common adsorbent used in water treatment.

Adsorption: The physical process occurring when liquids, gases, or suspended matter adhere to the surfaces of, or in the pores of, an adsorbent medium. Adsorption is a physical process which occurs without chemical reaction.

Aerosol: Aerosols are tiny particles suspended in the air. Some occur naturally, originating from volcanoes, dust storms, forest and grassland fires, living vegetation, and sea spray. Human activities, such as the burning of fossil fuels and the alteration of natural surface cover, also generate aerosols.

Alloy steel: Steel with modified properties made by combining iron with one or more elements in addition to carbon. Alloys change the properties of the steel making it, for example, harder, more formable, or more corrosion resistant, depending on the combination and amounts of alloys used.

Antipitting agent: An addition agent for electroplating solutions to prevent the formation of pits or large pores in the electrodeposits.

Aqueous: Pertaining to water; an aqueous solution is made by using water as a solvent.

Ash: The incombustible inorganic matter in the fuel.

ASTM: American Society for Testing of Materials.

Atmospheric air: Air under the prevailing atmospheric conditions.

Atmospheric corrosion: The gradual degradation or alteration of a material by contact with substances present in the atmosphere, such as oxygen, carbon dioxide, water vapor, and sulfur and chlorine compounds.

B

Bar: A shape of steel that is available in different forms such as rounds, squares, hexagons and rectangles.

Base material (metal): Substrate.

Blister: A raised area, often dome shaped, resulting from either loss of adhesion between a coating or deposit and the base metal or delamination under the pressure of expanding gas trapped in a metal in a near-subsurface zone.

Blistering: Formation of dome-shaped projections in paints or varnish films resulting from local loss of adhesion and lifting of the film from the underlying surface.

Breakdown potential: The least noble potential where pitting or crevice corrosion, or both, will initiate and propagate.

Brittle fracture: Separation of a solid accompanied by little or no macroscopic plastic deformation. Typically, brittle fracture occurs by rapid crack propagation with less expenditure of energy than for ductile fracture.

C

Carbon steel: Steel that has properties made up mostly of the element carbon and which relies on the carbon content for structure. Most of the steel produced in the world is carbon steel.

Cathodic corrosion: Corrosion of a metal when it is a cathode. (It usually happens to metals because of a rise in pH at the cathode or as a result of the formation of hydrides.)

Cathodic inhibitor: An inhibitor that reduces the corrosion rate by acting on the cathodic (reduction) reaction.

Cathodic protection: A corrosion control system in which the metal to be protected is made to serve as a cathode, either by the deliberate establishment of a galvanic cell or by impressed current.

Caustic: Any substance capable of burning or destroying animal flesh or tissue. The term is usually applied to strong bases.

Caustic cracking: Stress-corrosion cracking of metals in caustic solutions.

Caustic soda: The common name of sodium hydroxide.

Chemical conversion coating: A protective or decorative nonmetallic coating produced *in situ* by chemical reaction of a metal with a chosen environment. It is often used to prepare the surface prior to the application of an organic coating.

Chemical stability: Resistance to attack by chemical action.

Chlorine: A widely used gas used in the disinfection of water and an oxidizing agent for organic matter.

Chromate treatment: A treatment of metal in a solution of a hexavalent chromium (Cr VI) compound to produce a conversion coating consisting of trivalent (Cr III) and hexavalent chromium compounds.

- Chromium:** A steel-gray, lustrous, hard and brittle metallic element that takes its name from the Greek word for color (chrome) because of the brilliant colors of its compounds. It is found primarily in chromite. Resistant to tarnish and corrosion, it is a primary component of stainless steel and is used to harden steel alloys.
- Coating:** A paint, varnish, lacquer or other finish used to create a protective and/or decorative layer. Generally used to refer to paints and coatings applied in an industrial setting as part of the OEM process.
- Coating strength:** (a) A measure of the cohesive bond within a coating, as opposed to coating-to-substrate bond (adhesive strength); (b) the tensile strength of a coating, usually expressed in kpa (psi).
- Coating stress:** The stresses in a coating resulting from rapid cooling of molten material or semimolten particles as they impact the substrate. Coating stresses are a combination of body and textural stresses.
- Cold-rolling (CR):** Rolling steel without first reheating it. This process reduces thickness of the steel, produces a smoother surface, and makes it easier to machine.
- Conversion coating:** A coating consisting of a compound of the surface metal, produced by chemical or electrochemical treatments of the metal. Examples include chromate coatings on zinc, cadmium, magnesium, and aluminum and oxide and phosphate coatings on steel. See also Chromate treatment and Phosphatizing (phosphating or phosphate conversion coating).
- Copper plating:** The electrolytic deposition of copper to provide either a corrosion barrier (often as an undercoat for hard chrome plate) or for reclamation of worn parts.
- Copper strip corrosion:** A standard for the evaluation of an oil's tendency to corrode copper or copper alloys (see ASTM D130). Test results are based on the matching of corrosion stains. Noncorrosiveness is not to be confused with rust inhibiting, which deals with the protection of a surface from some contaminant, such as water, rather than the oil itself.
- Corrosion:** The chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties.
- Corrosion fatigue:** The process in which a metal fractures prematurely under conditions of simultaneous corrosion and repeated cyclic loading at lower stress levels or fewer cycles than would be required in the absence of the corrosive environment.
- Corrosion fatigue strength:** The maximum repeated stress that can be endured by a metal without failure under definite conditions of corrosion and fatigue and for a specific number of stress cycles and a specified period of time.
- Corrosion inhibitive:** A type of metal paint or primer that prevents rust by preventing moisture from reaching the metal. Zinc phosphate, barium metaborate, and strontium chromate (all pigments) are common ingredients in corrosion-inhibitive coatings. These pigments absorb any moisture that enters the paint film.
- Corrosion potential:** The potential of a corroding surface in an electrolyte relative to a reference electrode measured under open-circuit conditions.

Corrosion product: Substance formed as a result of corrosion.

Corrosion rate: The amount of corrosion occurring in unit time. (For example, mass change per unit area per unit time; penetration per unit time.)

Corrosion resistance: Ability of a metal to withstand corrosion in a given corrosion system.

Corrosive wear: Wear in which the chemical or electrochemical reaction with the environment is significant.

Corrosivity: Tendency of an environment to cause corrosion in a given corrosion system.

Creep: Time-dependent strain occurring under stress. The creep strain occurring at a diminishing rate is called primary creep; that occurring at a minimum and almost constant rate, secondary creep; and that occurring at an accelerating rate, tertiary creep.

Crevice corrosion: Localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment because of close proximity between the metal and the surface of another material.

D

Deactivation: The process of prior removal of the active corrosive constituents, usually oxygen, from a corrosive liquid by controlled corrosion of expendable metal or by other chemical means, thereby making the liquid less corrosive.

Defect: A discontinuity or discontinuities that by nature or accumulated effect (for example, total crack length) render a part or product unable to meet the minimum applicable acceptance standards or specifications.

Deposit: Foreign substance which comes from the environment, adhering to the surface of a material.

Deposit corrosion: Localized corrosion under or around a deposit or collection of material on a metal surface. See also Crevice corrosion.

Dew point: Temperature at which moisture will condense from humid vapors into a liquid state.

Dezincification: Corrosion in which zinc is selectively leached from zinc-containing alloys. Most commonly found in copper–zinc alloys containing <83% copper after extended service in water containing dissolved oxygen; the parting of zinc from an alloy (in some brasses, zinc is lost, leaving a weak, brittle, porous, copper-rich residue behind).

Diffusion: Spreading of a constituent in a gas, liquid, or solid, tending to make the composition of all the parts uniform.

Diffusion coating: Any process whereby a base metal or alloy is either (a) coated with another metal or alloy and heated to a sufficient temperature in a suitable environment or (b) exposed to a gaseous or liquid medium containing the other metal or alloy, thus causing diffusion of the coating or of the other metal or alloy into the base metal with resultant changes in the composition and properties of its surface.

Discontinuity: Any interruption in the normal physical structure or configuration of a part, such as cracks, laps, seams, inclusions, or porosity. A discontinuity may or may not affect the usefulness of the part.

Dissolved solids: The weight of matter in true solution in a stated volume of water; includes both inorganic and organic matter; usually determined by weighing the residue after evaporation of the water.

Dry corrosion: See gaseous or hot corrosion.

E

Electrical steel: Steel that includes silicon. The silicon content allows the steel to minimize energy loss during electrical applications.

Electroless nickel: The autocatalytic deposition of nickel/phosphorous and nickel/boron have many useful corrosion and corrosion wear applications. Unlike the electrolytic processes, they produce a deposit with completely uniform coverage. In the case of nickel/phosphorous, deposits around 25–50 μm thick with a hardness of about 500 Hv are obtained, but thermal ageing at temperatures around 400°C can develop hardness values in excess of 1000 Hv.

Electroplating: Electrodepositing a metal or alloy in an adherent form on an object serving as a cathode.

Embrittlement: The severe loss of ductility or toughness or both, of a material, usually a metal or alloy.

Environmental cracking: Brittle fracture of a normally ductile material in which the corrosive effect of the environment is a causative factor. Environmental cracking is a general term that includes corrosion fatigue, high-temperature hydrogen attack, hydrogen blistering, hydrogen embrittlement, liquid metal embrittlement, solid metal embrittlement, stress-corrosion cracking, and sulfide stress cracking.

Erosion: The progressive loss of material from a solid surface due to mechanical interaction between that surface and a fluid, a multicomponent fluid, or solid particles carried with the fluid.

Erosion–corrosion: A conjoint action involving corrosion and erosion in the presence of a moving corrosive fluid. Leads to the accelerated loss of material.

Exfoliation: Corrosion that proceeds laterally from the sites of initiation along planes parallel to the surface, generally at grain boundaries, forming corrosion products that force metal away from the body of the material, giving rise to a layered appearance.

F

Failure: An item of equipment is said to have suffered a failure when it is no longer capable of fulfilling one or more of its intended functions. Note that an item does not need to be completely unable to function to have suffered a failure.

Failure analysis: The systematic investigation of a component failure with the objectives of determining why the component failed and the corrective actions needed for preventing future failures.

Failure mode: The basic material behavior that resulted in the failure. Examples of failure mode include: ductile fracture, brittle fracture, fatigue fracture, corrosion, erosion, wear, and distortion.

Filiform corrosion: Corrosion that occurs under some coatings in the form of randomly distributed thread-like filaments. (A special form of crevice corrosion.)

Film: A thin, not necessarily visible, layer of material.

Film build: Thickness produced in a paint application.

Filter: Porous material through which fluids or fluid and solid mixtures are passed to separate matter held in suspension.

Fines: The portion of a powder composed of particles which are smaller than the specified size.

Flakes: Short, discontinuous internal fissures in wrought metals attributed to stresses produced by localized transformation and decreased solubility of hydrogen during cooling after hot working. In a fracture surface, flakes appear as bright silvery areas; on an etched surface, they appear as short, discontinuous cracks.

Free corrosion potential: Corrosion potential in the absence of net electrical current flowing to or from the metal surface.

Fretting: Surface damage resulting from relative motion between surfaces in contact under pressure.

Fretting corrosion: The deterioration at the interface between contacting surfaces as the result of corrosion and slight oscillatory slip between the two surfaces.

Fuel: A substance containing combustible used for generating heat.

G

Galvalume: A proprietary zinc alloy coating containing 55% aluminum with superior corrosion resistance.

Galvanizing: The process by which steel is coated with a layer of zinc. The zinc coating provides the steel with greater corrosion resistance.

Galvanic corrosion: Accelerated corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte.

Galvanic couple: A pair of dissimilar conductors commonly metals in electrical contact. See Galvanic corrosion.

Galvanic current: The electric current between metals or conductive nonmetals in a galvanic couple.

Galvanic series: A list of metals and alloys arranged according to their relative corrosion potentials in a given environment.

Galvanizing: To coat a metal surface with zinc using any of various processes.

Galvanneal: To produce a zinc-iron alloy coating on iron or steel by keeping the coating molten after hot dip galvanizing until the zinc alloys completely with the base metal.

Gaseous corrosion: Corrosion with gas as the only corrosive agent and without any aqueous phase on the surface of the metal, also called dry corrosion.

General corrosion: A form of deterioration that is distributed more or less uniformly over a surface; see uniform corrosion.

Graphitic corrosion: A form of selective leaching specific to the deterioration of metallic constituents in gray cast iron, which leaves the graphitic particles intact. (The term “graphitization” is commonly used to identify this form of corrosion but is not recommended because of its use in metallurgy for the decomposition of carbide to graphite.)

H

Hard water: Water which contains calcium or magnesium in an amount which requires an excessive amount of soap to form lather.

Hexavalent chromium: Chromium(VI) or Cr VI.

Hot corrosion: An accelerated corrosion of metal surfaces that results from the combined effect of oxidation and reactions with sulfur compounds and other contaminants, such as chlorides, to form a molten salt on a metal surface which fluxes, destroys, or disrupts the normal protective oxide.

Hot cracking: Also called solidification cracking. Hot cracking of weldments is caused by the segregation at grain boundaries of low-melting constituents in the weld metal. Hot cracking can be minimized by the use of low-impurity welding materials and proper joint design.

Hot dip coating: A metallic coating obtained by dipping the base metal or substrate into a molten metal.

Hot-rolling (HR): Rolling steel slabs into flat-rolled steel after it has been reheated.

Humidity test: A corrosion test involving exposure of specimens at controlled levels of humidity and temperature.

Hydrogen blistering: The formation of blisters on or below a metal surface from excessive internal hydrogen pressure. (Hydrogen may be formed during cleaning, plating, corrosion, etc.)

Hydrogen damage: A general term for the embrittlement, cracking, blistering, and hydride formation that can occur when hydrogen is present in some metals.

Hydrogen embrittlement: Hydrogen-induced cracking or severe loss of ductility caused by the presence of hydrogen in the metal. Hydrogen absorption may occur during electroplating, pickling, or other processes that favor the production of nascent or elemental hydrogen.

I

Impingement corrosion: A form of erosion-corrosion generally associated with the local impingement of a high-velocity, flowing fluid against a solid surface.

Inclusions: Particles of a foreign material in a metallic matrix. The particles are usually compounds (such as oxides, sulfides, or silicates), but may be of any substance that is foreign to (and essentially insoluble in) the matrix.

Incubation period: A period prior to the detection of corrosion while the metal is in contact with a corrosive agent.

Industrial atmosphere: An atmosphere in an area of heavy industry with soot, fly ash, and sulfur compounds as the principal constituents.

Inhibitor: A chemical substance or combination of substances that, when present in the proper concentration and forms in the environment, prevents or reduces corrosion.

Inorganic zinc-rich paint: Coating containing a zinc powder pigment in an inorganic vehicle.

Interconnected porosity: A network of pores in and extending to the surface of a coating.

Intercrystalline corrosion: See intergranular corrosion.

Intergranular: Between crystals or grains.

Intergranular corrosion: Preferential corrosion at or adjacent to the grain boundaries of a metal or alloy.

Intergranular cracking: Cracking or fracturing that occurs between the grains or crystals in a polycrystalline aggregate. Also called intercrystalline cracking.

Intergranular fracture: Brittle fracture of a metal in which the fracture is between the grains, or crystals, that form the metal. Also called intercrystalline fracture. Contrast with transgranular fracture.

Internal oxidation: The formation of isolated particles of corrosion products beneath the metal surface. This occurs as the result of preferential oxidation of certain alloy constituents by inward diffusion of oxygen, nitrogen, sulfur, and so on.

Isocorrosion diagram: A graph or chart that shows constant corrosion behavior with changing solution (environment) composition and temperature.

L

Lamellar corrosion: A form of corrosion in which the expanding corrosion products stack up as layers. Similar to exfoliation of high strength aluminum alloys.

Liquid impingement erosion: Progressive loss of material from a solid surface due to continue exposure to impacts by liquid drops or jets.

Liquid metal embrittlement: Catastrophic brittle failure of a normally ductile metal when in contact with a liquid metal and subsequently stressed in tension.

Liter: The basic metric unit of volume; 3.785 L is equal to 1 U.S. gallon; 1 L of water weighs 1000 g.

Local action corrosion: Corrosion caused by local corrosion cells on a metal surface.

Local cell: A galvanic cell resulting from inhomogeneities between areas on a metal surface in an electrolyte. The inhomogeneities may be of physical or chemical nature in either the metal or its environment.

Local corrosion cell: An electrochemical cell created on a metal surface because of a difference in potential between adjacent areas on that surface.

Localized corrosion: Corrosion at discrete sites, for example, pitting, crevice corrosion, and stress corrosion cracking.

Lubricant: Any substance interposed between two surfaces for the purpose of reducing the friction or wear between them.

M-N-O

Maximum contaminant level (MCL): The maximum allowable concentration of a contaminant in water as established in the U.S. EPA Drinking Water Regulations.

Mechanical filter: A filter primarily designed for the removal of suspended solid particles, as opposed to filters with additional capabilities.

Mesa corrosion: Mesa corrosion is one of the common types of corrosion experienced in service involving exposure of carbon or low-alloy steels to flowing wet carbon dioxide conditions at slightly elevated temperatures. An iron carbonate surface scale will often form in this type of environment which can be protective, rendering a very low corrosion. However, under

the surface shear forces produced by flowing media, this scale can become damaged in a localized attack that produces mesa-like features.

Microbiologically influenced corrosion: Sometimes called Microbial Corrosion or Bio corrosion, it refers to corrosion that is affected by the action of micro-organisms in the environment.

Micrometer (μm): Formally known as micron. A linear measure equal to one millionth of a meter or 0.00003937 in. The symbol for the micrometer is μm .

Moisture: Water in the liquid or vapor phase.

Nickel plating: The electrolytic deposition of nickel to form a corrosion barrier or to reclaim a worn part. Can also include hard ceramic particles to form a wear-resistant composite coating.

Noble metal: A metal with a standard E.P that is more noble (positive) than that of hydrogen.

NOX: Abbreviation for all of the family of oxides of nitrogen.

Oxidation: Loss of electrons by a constituent of a chemical reaction. (Also refers to the corrosion of a metal that is exposed to an oxidizing gas at elevated temperatures.)

Oxidized surface (on steel): Surface having a thin, tightly adhering, oxidized skin (from straw to blue in color), extending in from the edge of a coil or sheet.

Oxidizing agent: A compound that causes oxidation, thereby itself being reduced.

Oxidizing atmosphere: An atmosphere which tends to promote the oxidation of materials.

Oxygen: Gas used to support combustion of fuel gases in combustion thermal spray processes. Achieves much higher flame temperatures than using air.

Oxygen attack: Corrosion or pitting in a boiler caused by oxygen.

P

Packrust: This particular form of corrosion is often used in relation to bridge inspection to describe built-up members of steel bridges which are already showing signs of rust packing between steel plates.

Particle size: (a) A measure of dust size, expressed in microns or percent passing through a standard mesh screen; (b) the size of a particle suspended in water as determined by its smallest dimension.

Parting: The selective corrosion of one or more components of a solid solution alloy.

Parts per billion (ppb): A measure of proportion by weight, equivalent to one unit weight of a material per billion (10^9) unit weights of compound.

Parts per million (ppm): A measure of proportion by weight, equivalent to one unit weight of a material per million (10^6) unit weights of compound.

Passivation: The process in metal corrosion by which metals become passive.

Passivator: A type of inhibitor which appreciably changes the potential of a metal to a more noble (positive) value.

Passive: The state of the metal surface characterized by low corrosion rates in a potential region that is strongly oxidizing for the metal.

Passivity: A condition in which a piece of metal, because of an impervious covering of oxide or other compound, has a potential much more positive than that at the metal in the active state.

Patina: The coating, usually green, that forms on the surface of metals such as copper and copper alloys exposed to the atmosphere. Also used to describe the appearance of a weathered surface of any metal.

Percent solids: The percentage mass of nonliquid components in paint.

Permeability: A property measured as a rate of passage of a liquid or gas through a coating.

pH: A measure of the acidity or alkalinity of a solution; the negative logarithm of the hydrogen-ion activity; it denotes the degree of acidity or basicity of a solution. At 25°C, 7.0 is the neutral value. Decreasing values below 7.0 indicate increasing acidity; increasing values above 7.0, increasing basicity.

Phosphatizing (phosphating or phosphate conversion coating): Phosphatizing is a metal pretreatment primarily used to prepare steel for paint or coatings and to prevent corrosion. Phosphatizing is termed a conversion coating because, unlike paint or traditional coatings, it does not lie on the surface of the metal, but rather the surface of the metal is chemically changed to a new substance. The coating will, therefore, not chip- or scratch-off exposing the base material to corrosion and wear.

Pitting: Corrosion of a metal surface, confined to a point or small area that takes the form of cavities.

Pitting factor: Ratio of the depth of the deepest pit resulting from corrosion divided by the average penetration as calculated from weight loss.

Pitting resistance equivalent number: An empirical relationship to predict the pitting resistance of austenitic and duplex stainless steels.

Poultice corrosion: A term used in the automotive industry to describe the corrosion of vehicle body parts due to the collection of road salts and debris on ledges and in pockets that are kept moist by weather and washing. Also called deposit corrosion or attack.

Powder coating: A polymeric coating deposited via electrostatic attraction and applied to the surface as a dry, finely ground powder and then heated above its melting point so the powder particles flow together or cure.

Precious metal: One of the relatively scarce and valuable metals: gold, silver, and the platinum-group metals. Also called noble metal(s).

Precipitate: To separate materials from a solution by the formation of insoluble matter by chemical reaction.

Products of combustion: The gases, vapors, and solids resulting from the combustion of fuel.

Protection potential: The most noble potential where pitting and crevice corrosion will not propagate.

Protective potential: The threshold value of the corrosion potential that has to be reached to enter a protective potential range. The term used in cathodic protection to refer to the minimum potential required to control corrosion.

Protective potential range: A range of corrosion potential values in which unacceptable corrosion resistance is achieved for a particular purpose.

Purge: To introduce air into a vessel flue passages in such volume and manner as to completely replace the air or gas-air mixture contained therein.

R

Reactive metal: A metal that readily combines with oxygen at elevated temperatures to form very stable oxides, for example, titanium, zirconium, and beryllium.

Red water: Water which has a reddish or brownish appearance due to the presence of precipitated iron and/or iron bacteria.

Reducing agent: A compound that causes reduction, thereby itself becoming oxidized.

Reducing atmosphere: An atmosphere which tends to (1) promote the removal of oxygen from a chemical compound; (2) promote the reduction of immersed materials.

Reduction: The gain of electrons by a constituent of a chemical reaction.

Relative humidity: The ratio, expressed as a percentage, of the amount of water vapor present in a given volume of air at a given temperature to the amount required to saturate the air at that temperature.

Ringworm corrosion: Localized corrosion frequently observed in oil well tubing in which a circumferential attack is observed near a region of metal “upset.”

Rust: A corrosion product consisting primarily of hydrated iron oxide. A term properly applied only to ferrous alloys.

S

Sacrificial coating: A coating that provides corrosion protection wherein the coating material corrodes in preference to the substrate, thereby protecting the latter from corrosion.

Saline water: Water containing an excessive amount of dissolved salts, usually over 5000 mg/L.

Salinity: The total proportion of salts in seawater, often estimated empirically as chlorinity $\times 1.80655$, also expressed in parts per thousand (or permille), which is approximately grams of salt per kilogram of solution.

Salt: In chemistry, the term is applied to a class of chemical compounds which can be formed by the neutralization of an acid with a base; the common name for the specific chemical compound sodium chloride used in the regeneration of ion exchange water softeners.

Salt fog: ASTM-B-117 test procedure that attempts to simulate the corrosive environment caused by road salt and marine spray.

Saturated air: Air which contains the maximum amount of water vapor that it can hold at its temperature and pressure.

Scale: A deposit of mineral solids on the interior surfaces of water lines and containers often formed when water containing the carbonates or bicarbonates of calcium and magnesium is heated. Oxide of iron that forms on the surface of steel after heating.

Scanning electron microscope (SEM): An electron microscope in which the image is formed by a beam synchronized with an electron probe scanning the object. The intensity of the image forming beam is proportional to the scattering or secondary emission of the specimen where the probe strikes it.

Scoring: A severe form of wear characterized by the formation of extensive grooves and scratches in the direction of sliding.

Sealant, sealer: A preparation of resin or wax type materials for sealing the porosity in coatings.

Sealing: A process which, by absorption of a sealer into thermal spray coatings, seals porosity and increases resistance to corrosion of the underlying substrate material.

Season cracking: See stress-corrosion cracking.

Shelf life: The length of time any unopened container (of paint, for example) can be stored at the supplier recommended storage temperature and still retain the properties in both the unmixed and mixed states as required by the specification or advertised in the product data sheets.

Silver plating: The electrodeposition of silver for electrical, decorative, or antifretting properties.

Sodium chloride: The chemical name for common salt.

Soft water: Water which contains little or no calcium or magnesium salts, or water from which scale forming impurities have been removed or reduced.

Solution: A homogeneous dispersion of two or more kinds of molecular or ionic species. Solutions may be composed of any combination of liquids, solids, or gases, but they always consist of a single phase.

Soot: Unburned particles of carbon derived from hydrocarbons.

Sour water: Waste waters containing fetid materials, usually sulfur compounds.

Specialty steel: Steels such as electrical, alloy, or stainless steels. These generally are produced in smaller volumes to meet the specific needs of customers.

Stress-corrosion cracking: A cracking induced from the combined influence of tensile stress and a corrosive environment.

Substrate: The parent or base material to which a coating is applied.

Subsurface corrosion: See internal oxidation.

Sulfidation: The reaction of a metal or alloy with a sulfur-containing species to produce a sulfur compound that forms on or beneath the surface of the metal or alloy.

T

Thermogalvanic corrosion: The corrosive effect resulting from the galvanic cell caused by a thermal gradient across the metal surface.

Tinplate: Thin steel sheet with a very thin coating of metallic tin. Used primarily in can-making.

Topcoat: Usually the final paint film applied to a surface.

Total acidity: The total of all forms of acidity, including mineral acidity, carbon dioxide, and acid salts. Total acidity is usually determined by titration with a standard base solution to the phenolphthalein endpoint (pH 8.3).

Total alkalinity: The alkalinity of a water as determined by titration with standard acid solution to the methyl orange endpoint (pH approximately 4.5); total alkalinity includes many alkalinity components, such as hydroxides, carbonates, and bicarbonates.

Total chlorine: The total concentration of chlorine in water, including combined and free chlorine.

Total dissolved solids (TDS): The weight of solids per unit volume of water which are in true solution, usually determined by the evaporation of a measured volume of filtered water, and determination of the residue weight.

Trace: A very small concentration of a material, high enough to be detected but too low to be measured by standard analytical methods.

Transgranular cracking: Cracking or fracturing that occurs through or across a crystal or grain. Also called transcrySTALLine cracking.

Transition metal: A metal in which the available electron energy levels are occupied in such away that the d-band contains less than its maximum number of 10 electrons per atom, for example, iron, cobalt, nickel, and tungsten. The distinctive properties of the transition metals result from the incompletely filled d-levels.

Trap: A receptacle for the collection of undesirable material.

U-V-W-Z

Uniform corrosion: Corrosion that proceeds at about the same rate over a metal surface.

Varnish (clearcoat): An unpigmented binder solvent solution applied to protect or decorate a surface.

VCI: Vapor-Phase Corrosion Inhibitor.

Viscosity: The resistance of fluids to flow, due to internal forces and friction between molecules, which increases as temperature decreases.

Volatile: Capable of vaporization at a relatively low temperature.

Volatile matter: Those products given off by a material as gas or vapor, determined by definite prescribed methods.

Volatile organic compound (VOC): Organic chemicals and petrochemicals that emit vapors while evaporating. In paints, VOC generally refers to the solvent portion of the paint which, when it evaporates, results in the formation of paint film on the substrate to which it was applied.

Volatile solids: Matter which remains as a residue after evaporation at 105 or 180°C, but which is lost after ignition at 600°C. Includes most forms of organic matter.

Weak base load faction: The sum of the chloride, sulfate, and nitrate in a given water.

White rust: Zinc oxide, the powdery product of corrosion of zinc or zinc-coated surfaces.

Zinc plating: The electrodeposition of zinc or zinc alloys (e.g., Zn/Ni, Zn/Sn) to provide galvanic corrosion protection.

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4 Lubrication of Distribution Electrical Equipment

4.1 LUBRICATION PRIMER

4.1.1 PURPOSE OF LUBRICATION

The primary purpose of lubrication is to reduce friction between moving metal surfaces. To keep metal surfaces separated, lubricating grease should wet the metal and resist being displaced by the pressures it encounters. A lubricant can also serve as a coolant, prevent corrosion, and block the entry of contaminants. Satisfactory grease will also resist separation, be reasonably stable, and not significantly change its nature within the temperature range for which it was designed [1–8].

Lubricants are widely used in electrical connectors, switches, and circuit breakers. Lubricants improve the performance of electrical apparatus in many ways, such as *reducing mating forces, extending plating durability, and enhancing corrosion protection* (fretting, galvanic, and harsh environments). Good grease will flow into bearings when applied under pressure and remain in contact with moving surfaces. It will not leak out from gravitational or centrifugal action, nor will it stiffen in cold temperature where it unduly resists motion [9,10].

Lubricants *prevent environmental and galvanic corrosion* on electrical contacts. Airborne contaminants attack metals, causing oxides to gradually build up in pores until they reach the surface, where they impede current flow. Contact surfaces and switches made of dissimilar metals are especially susceptible to moisture, oxygen, and aggressive gases. Even noble-metal plating is at risk if it is worn or porous. The purpose of lubricant is to prevent dust, water, dirt, and other contaminants from entering the part being lubricated.

Lubricants *reduce wear and heat* between contacting surfaces in relative motion. While wear and heat cannot be completely eliminated, they can be reduced to negligible or acceptable levels, especially on sliding electrical contacts which see repetitive cycling or arc damage, two common causes of failures. Although evidence suggests that lubricants change or reduce arc patterns, the lubricant's real job on sliding contacts is to separate the surfaces during operation and keep debris out of the contact area. Otherwise, the microscopic wear particles oxidize quickly, turning into insulators. Build-up of oxide particles also accelerates wear. In general, hydrocarbon lubricants work best at wear prevention because their molecular structure is more

rigid than other base oils. Proper lubricants strike a balance between preventing wear and maintaining electrical continuity.

Because heat and wear are associated with friction, both effects can be minimized by reducing the coefficient of friction between the contacting surfaces. Lubricants *reduce the friction* between mechanical components, thus reducing the amount of force needed to activate a swift motion. Lubricants usually ensure a coefficient of friction of 0.1 or less, which means it takes little force to operate a device with a high preload. This can be important in switches and circuit breakers (CBs) where high normal forces ensure low contact resistance (CR) and a stable signal or power path. Lubrication is also mechanically important because it gives the end user smooth, uniform operation.

Care must be taken to select the proper lubricant to achieve the desired results. In choosing grease, the three primary elements that go into the making of grease should be considered: the liquid lubricant (petroleum or synthetic fluid), the thickening agent, and additives. The chosen grease must be heavy enough to provide the right film strength, yet be light enough to flow well in cold temperatures.

The person selecting the grease should investigate which solid or liquid additives, such as the extreme pressure (EP) type, will do the job well. For example, to lubricate open gears, grease containing a tacky additive must be used to keep the grease in place. The grease should be compatible with other materials used with the parts being lubricated. Manufacturers may specify the type of grease to be used in their equipment.

4.1.2 LUBRICATION TERMINOLOGY

Various lubrication terms have been accepted and widely used in the industry to describe the physical properties of lubricating materials [2–4,11].

Viscosity is a measure of flowability. It is the resistance to flow caused by internal friction between the lubricant molecules. This characteristic helps determine the load-carrying capacity, thickness of the lubricating film, and operating temperature. In selecting a lubricant for a particular application, definition of the required viscosity level at start-ups and during operation conditions is critically important to ensure optimum lubricant performance. Viscosity can be expressed as the number of seconds required for a measured volume of oil to flow through a specified orifice in standard conditions. In the United States viscosity is usually measured and specified between 100°F and 210°F (~40–100°C).

We introduce another term to distinguish between the viscosity of oil and the viscosity of grease; the viscosity of grease is referred to as *apparent viscosity*. Apparent viscosity is the viscosity of a grease that holds only for the shear rate and temperature at which the viscosity is determined. At start-up, grease has resistance to motion, implying high viscosity. However, as grease is sheared between wearing surfaces and moves faster, its resistance to flow reduces. Its viscosity decreases as the rate of shear increases. By contrast, oil at a constant temperature would have the same viscosity at start-up as what it has when moving.

Viscosity index indicates how viscosity varies with temperature. The property can be an important consideration in applications where operating temperatures vary widely, particularly when low temperatures are encountered.

Pour point is the lowest temperature at which oil flows and is most critical in low-temperature applications. The formation of wax crystals causes flow failure in paraffinic oils.

Dropping point is an indicator of the heat resistance of grease. As grease temperature rises, penetration increases until the grease liquefies and the desired consistency is lost. The dropping point is the temperature at which grease becomes fluid enough to drip. It indicates the upper temperature limit at which grease retains its structure, not the maximum temperature at which grease may be used. A few greases have the ability to regain their original structure after cooling down from the dropping point.

Flash point is the temperature at which oil gives off ignitable vapors. The flash point is not necessarily a safe upper limit for oil because some decomposition takes place below the flash point.

Fire point is the temperature at which oil will burn if ignited.

Oxidation stability is the ability of grease to resist a chemical union with oxygen. The reaction of grease with oxygen produces insoluble gum, sludges, and lacquer-like deposits that cause sluggish operation, increased wear, and reduction of clearances. Prolonged high-temperature exposure accelerates oxidation in greases.

Pumpability and slumpability. Pumpability is the ability of a grease to be pumped or pushed through a system. More practically, pumpability is the ease with which a pressurized grease can flow through lines, nozzles, and fittings of grease-dispensing systems. Slumpability, or feedability, is its ability to be drawn into (sucked into) a pump. Fibrous greases tend to have good feedability but poor pumpability. Buttery-textured greases tend to have good pumpability but poor feedability.

Shear stability. Grease consistency may change as it is mechanically worked or sheared between wearing surfaces. A grease's ability to maintain its consistency when it is worked is its shear stability or mechanical stability. A grease that softens as it is worked is called thixotropic. Greases that harden when they are worked are called rheoplectic.

4.1.3 TYPES OF LUBRICATING MATERIALS

There are three major types of lubricants: oils (fluid lubricants), greases (soft substances), and solid lubricants [2–8].

4.1.3.1 Oil

Oil covers a broad class of fluid lubricants, each of which has particular physical properties and characteristics. Basically, petroleum lubrication oils (mineral oils) are made from naphthenic or paraffinic crude oil. Naphthenic oils contain little wax and their low pour point makes them good lubricants for most applications. Paraffinic oils, on the other hand, are very waxy. Lubricants made from them are used mainly in hydraulic equipment and other machinery.

4.1.3.2 Synthetic Oils

Synthetic oils are being used for instrument bearings, hydraulics, air compressors, gas and steam turbines and many other applications. Silicones are not true oils; their

principal advantages are excellent viscosity–temperature characteristics, good resistance to oxidation, and a wide operating temperature range.

4.1.3.3 Grease

Grease consists of a thickening agent, oil or synthetic fluid and additives. Various thickeners provide different properties of grease [12–14]. Greases are usually ranked by their consistency on a scale set up by the National Lubricating Grease Institute (NLGI). Consistency or grade numbers range from 000 to 6, corresponding to specified ranges of penetration numbers (Table 4.1).

Grease consistency depends on the type and amount of thickener used and the viscosity of its base oil. Consistency of grease is its resistance to deformation by an applied force. The measure of consistency is called penetration. Penetration depends on whether the consistency has been altered by handling or working. ASTM D 217 and D 1403 methods measure penetration of unworked and worked greases. The softest greases are rated at 000 (liquid), with higher numbers indicating harder grease. Most greases fall in the range from 1 to 2 (soft) but some are hard (NLGI in the range 5–6).

4.1.3.4 Synthetic Lubricants

Base stocks for synthetic lubricant are esters, synthetic hydrocarbons (SHC), polyglycols, silicones, and so on. Synthetic greases provide a cost-effective, lifetime lubrication for bearings and other moving parts, for gaskets and seals. High thermal stability and chemical inertness make it useful for aerospace, electrical, automotive, and other high-tech or industrial applications. Synthetic lubricants usually keep their lubrication characteristics at temperatures in the range of –73°C to 290°C (–100°F to 550°F), maintain good viscosity over a wide temperature range, and are nonflammable with no autogeneous ignition, flash, or fire point up to 650°C (1,200°F).

TABLE 4.1
NLGI Grease Classification

NLGI Number	ASTM Worked Penetration	
	0.1 mm (3.28 × 10 ^{–4} ft) at 25°C (77°F)	Consistency
000	445–475	Semifluid
00	400–430	Semifluid
0	355–385	Very soft
1	310–340	Soft
2	265–295	Common grease
3	220–250	Semihard
4	175–205	Hard
5	130–160	Very hard
6	85–115	Solid

Source: Adapted from Facilities Instructions, Standards, and Techniques, In *Lubrication of Power Plant Equipment*, Vol. 2–4, United States Department of the Interior Bureau of Reclamation, 1990, Online. Available: http://www.usbr.gov/power/data/fist/fist2_4/vol2-4.pdf.

The label “synthetic lubricants” covers a broad category of fluids and pastes having varied properties. They are available in a variety of forms, from light oils to thick greases. Synthetic lubes [6,7,15] have a longer product life, are more inert than petroleum materials, and generate less waste. They have a capability for a wider range of temperatures, from extremely low to high; certain classifications are friendlier to elastomers, seals, and O-rings that come in contact with the lubricant.

4.1.3.5 Solid Lubricants

Solid lubricants are usually fine powders, such as molybdenum disulfide, graphite, and Teflon (polytetrafluoroethylene (PTFE)). They can be used as additives in greases or dispersions, as dry film bonded lubricants, or alone. Lubricating solids can provide longer-term lubrication than unfortified oils and greases because of their ability to form burnished films on surfaces and stay longer.

4.1.3.6 Silicones

Silicones are very stable and very inert lubricants, which provide wider operating temperature ranges than nonsilicone synthetic lubes. *Fluorosilicones* have some of the advantages of other silicones, such as dimethyl and phenylmethyl silicones, plus higher resistance to harsh environments and the ability to carry heavy bearing loads.

4.1.4 GREASE COMPOSITION AND PROPERTIES

Grease composition may be described by a simple formula: *Lubricating grease = Fluids + Thickener + Additives* [11–14]. Various types of fluids, thickeners, and additives are presented in Tables 4.2 through 4.4. The grease properties depend on how much and what type of each component is included in the grease composition.

TABLE 4.2
Grease Composition: Fluids (75%–95%)

Fluid Group	Fluid Type
Mineral oils	Paraffinic oil
	Naphtenic oil
Synthetic hydrocarbons (SHC)	Phosphate esters
	Di-esters
	Organic esters
	Polyglycols
	Polyalphaolefin
	Polyphenyl ether
	Silicate ether or disiloxane
	Chlorinated phenyl methyl silicones
Silicones	Methyl silicones
	Phenyl methyl silicones
	PFPE
Fluorocarbons	

TABLE 4.3
Grease Composition: Thickeners (5%–20%)

Thickener Group	Thickener Type
Soaps	Lithium, Li complex
	Sodium (Na) complex
	Barium (Ba) (conventional, anhydrous, complex)
	Calcium (Ca) (conventional, anhydrous, complex), Ca sulfonate
	Aluminum, Al complex
Nonsoap (inorganic)	Strontium (Sr)
	Microgel
	Bentonite (Clay)
	Carbon black
	Silica-gel
Nonsoap (organic)	Fumed silica
	Urea compounds (polyurea)
	Polytetrafluoro ethylene (PFTE, Teflon)
	Fluorine compounds
	Terephthalate, organic dyes

4.1.4.1 Properties of Greases with Different Types of Thickeners

There are many different classes of materials used as thickeners in grease manufacturing: simple and complex metal soaps, and inorganic and organic nonsoaps; the role of a thickener is to give grease its characteristic consistency and the thickener is sometimes thought of as a “three-dimensional fibrous network” or a “sponge” that holds the oil in place. The thickener is a material that will, in combination with the selected lubricant, produce the solid to semifluid structure.

The primary type of thickener used in grease is metallic soaps. These soaps include lithium, aluminum, clay, polyurea, sodium, and calcium (Table 4.3). Lately, complex thickener-type greases are gaining popularity. They are being selected because of their high dropping points and excellent load-carrying abilities. Complex greases are made by combining the conventional metallic soap with a complexing agent. The most widely used complex grease is lithium based. These are made with a combination of the conventional lithium soap and a low-molecular-weight organic acid as the complexing agent.

Nonsoap thickeners are also gaining popularity in special applications such as high-temperature environments. Bentonite and silica aerogel are two examples of thickeners that do not melt at high temperatures. The properties and applications of greases with different thickeners [14] are presented in Table 4.4.

A thickener’s efficiency depends on how much of it is needed to make a given grade (stiffness) of grease. The primary lubricating component is oil, so it is beneficial to have as much oil in the formulation as possible. But a lubricant should not be too viscous; otherwise it causes hydroplaning (an open-circuit condition), especially at low temperature.

A thickener’s ability to resist water is also an important consideration. Even in devices that are generally protected from the environment, humidity can condense

TABLE 4.4
Properties of the Greases with Different Thickeners

Properties	Type of Grease			
	Lithium	Li complex	Polyurea	Organo-clay
Dropping point, °C (°F)	177–204 (350–400)	260+ (500+)	243 (470)	260+ (500+)
Maximim temperature, °C (°F)	135 (275)	177 (350)	177 (350)	177 (350)
Water resistance	Good	Good to excellent	Good to excellent	Fair to excellent
Work stability	Good to excellent	Good to excellent	Poor to good	Fair to good
Oxidation stability	Fair to excellent	Fair to excellent	Good to excellent	Good
Protection against rust	Poor to excellent	Fair to excellent	Fair to excellent	Poor to excellent
Oil separation	Good to excellent	Good to excellent	Good to excellent	Good to excellent
Appearance	Smooth and buttery	Smooth and buttery	Smooth and buttery	Smooth and buttery
Other properties	EP grades, reversible	EP grades	EP grades	—

Source: Adapted from Facilities Instructions, Standards, and Techniques, In *Lubrication of Power Plant Equipment*, Vol. 2–4, United States Department of the Interior Bureau of Reclamation, 1990, Online. Available: http://www.usbr.gov/power/data/fist/fist2_4/vol2-4.pdf.

inside them and displace the grease or it can become entrained and accelerate corrosion. Lithium-soap greases have good freshwater resistance, but poor saltwater resistance. Clay and PTFE generally perform well in wet applications. PTFE also lowers friction, especially on plastic components [16].

4.1.4.2 Additives

The additives are used in the greases to enhance desirable properties and suppress undesirable ones, as well as add new properties to a lubrication product [14]. Various additives are listed in Table 4.5, and their functions include surface protection, grease performance enhancement, and lubricant preservation. These functions are explained below.

TABLE 4.5
Grease Composition: Additives (0–15%)

Oxidation Inhibitors	Emulsifiers
Rust/corrosion inhibitors	Demulsifiers
Antiwear agents	Pour point depressants
EP additives	Tackiness/adhesive agents
Acid neutralizers	Viscosity modifiers
Antifoam additives	Oiliness enhancers
Detergents	Solid additives (MoS ₂ , graphite)
Dispersants	Perfumes, dyes

4.1.4.2.1 *Oxidation Inhibitors (Antioxidants)*

Oxidation inhibitors (antioxidants) reduce oxidation. Their various types are: oxidation inhibitors, retarders, anticatalyst metal deactivators, and metal passivators. Oxidation inhibitors, or antioxidants, lengthen a lubricant's service or storage life by increasing its oxidation resistance either through binding free oxygen in the oil or through neutralizing the catalytic effect of metals.

4.1.4.2.2 *Rust/Corrosion Inhibitors*

Rust/corrosion inhibitors reduce the rusting of ferrous surfaces swept by oil, as well as the corrosion of cuprous and other metals. Rust inhibitors protect ferrous (iron or steel) parts by forming a film on the part that resists attack from water. Corrosion inhibitors act in a similar way to protect nonferrous parts and also act to neutralize acids with a basic compound such as calcium carbonate.

4.1.4.2.3 *Antiwear Agents*

Antiwear agents reduce wear and prevent scuffing or rubbing surfaces under steady load operating conditions. Antiwear additives work by coating the metal surface. If light metal-to-metal contact is made, the heat from the friction melts the additives, forming a liquid layer between the surfaces. This molten additive layer, being softer than the metal, acts as a lubricant, preventing wear of the metal surfaces.

4.1.4.2.4 *EP Additives*

EP additives prevent scuffing or rubbing surfaces under severe operating conditions, for example, heavy shock load, by the formation of a mainly inorganic surface film. EP additives work by reacting with a metal to form a compound that acts as a protective layer on the metal's surface. Because this layer is softer than the metal itself, under EP conditions, the compound layer wears away first, protecting the metal. As this layer is removed, the EP additive acts to form another layer.

In contrast to the action of antiwear additives, EP additives control wear instead of preventing it. Some EP additives, because of their reactive nature, can be corrosive to brass or copper-containing alloys. To prevent excessive corrosion, most EP additives are activated by the heat of friction created during EP conditions but do not react at room temperature.

4.1.4.2.5 *Acid Neutralizers*

Acid neutralizers neutralize contaminating strong acids that are formed, for example, by combustion of high-sulfur fuels or by decomposition of active EP additives.

4.1.4.2.6 *Antifoam Additives*

Antifoam additives reduce surface foam. Foam inhibitors prevent lubricant foaming by decreasing the surface tension of air bubbles, allowing them to combine into large ones, which break more rapidly.

4.1.4.2.7 *Detergents*

Detergents reduce or prevent deposits formed at high temperatures (e.g., in internal combustion engines).

4.1.4.2.8 *Dispersants*

Dispersants prevent deposition of sludge by dispersing a finely divided suspension of the insoluble material formed at low temperature. Detergents and dispersants are primarily used in engine oils to keep the surfaces free of deposits and to keep contaminants dispersed in the lubricant.

4.1.4.2.9 *Demulsifiers*

Demulsifiers promote the separation of oil and water in lubricants exposed to water.

4.1.4.2.10 *Emulsifiers*

Emulsifiers form emulsions, either water-in-oil or oil-in-water, according to type. An emulsifier promotes the rapid mixing of oil and water to form a stable emulsion. Emulsifiers are used in motor oils to allow water, formed by combustion of fuel, to be kept in emulsion until engine heat can evaporate it. Emulsifiers are also used in soluble oils used in some metal working operations and in fire-resistant hydraulic fluids. Emulsification is usually not a desirable property in most hydraulic fluids or turbine oils.

4.1.4.2.11 *Pour-point Depressants*

Pour-point depressants reduce the pour point of paraffinic oils, and enable lubricants to flow at low temperature.

4.1.4.2.12 *Tackiness Agents*

Tackiness agents reduce the loss of oil by gravity, for example, from vertical sliding surfaces, or by the centrifugal force. Tackiness agents act to increase the adhesiveness of an oil or grease.

4.1.4.2.13 *Viscosity Modifiers (Index Improvers)*

Viscosity modifiers (index improvers) reduce the decrease in viscosity caused by an increase in temperature. VI improvers lower the rate of change in viscosity with temperature and are used to produce multigrade motor oils.

4.1.4.2.14 *Oiliness Enhancers/Lubricity Additives*

Oiliness enhancers/lubricity additives reduce friction under boundary lubrication conditions; they increase the load-carrying capacity where it is limited by temperature rise (TR) by the formation of mainly organic surface films. Lubricity, also referred to as oiliness, with respect to lubricating oil, is defined as the ability of an oil to reduce friction between moving surfaces. Lubricity additives, usually vegetable or animal fats, enhance lubricity by tenaciously adhering to the metal's surface, forming an adsorbed film of high lubricating value.

4.2 INCOMPATIBILITY OF LUBRICANTS

4.2.1 DEFINITION OF INCOMPATIBILITY

Greases are considered incompatible when the physical or performance characteristics of the mixed greases fall below original specifications. The NLGI Lubricating

Grease Guide [17] defines grease incompatibility as the lessening of the performance capability and physical properties when two greases are mixed. Grease incompatibility will be revealed by any of the several areas, such as: (1) lower heat resistance; (2) change in consistency, usually softening; or (3) decrease in shear stability. Mixtures that show none of these changes are considered compatible.

Since each of the greases in a mixture is a combination of thickener, base oil, and additives, incompatibility is not always due to the thickener alone. Sometimes, the thickener of one grease is incompatible with the oil or additives present in the other grease. Incompatibility is not predictable and is best determined in service test or in service-related tests.

ASTM International Committee D02.G developed ASTM D6185, "Standard Practice for Evaluating Compatibility of Binary Mixtures of Lubricating Greases," in 1997. This document defines the procedure for evaluating the basic compatibility of greases, which is determined by measuring the dropping point, the mechanical stability and the change in consistency of the mixture upon heating.

A mixture of two greases is considered to be incompatible if the test proves that the mixture is significantly softer; less shear stable, or less heat resistant than the original greases. Certain thickener combinations are generally recognized to be incompatible, for example, lithium and sodium grease and organo-clay and most soap greases. However, there is no practical rule one can apply to all mixtures of different greases to determine the compatibility properties [18].

4.2.2 CAUSES OF INCOMPATIBILITY

4.2.2.1 Base Oils

Lubricating oil or grease is a mixture of oil (synthetic or mineral) and different additives. Compatibility problems may occur when different types of oils from one or more suppliers are being mixed. Insoluble reaction products are formed in the presence of water in a mixture of different oils (e.g., hydraulic and trunk piston engine oils). Such mixtures should always be avoided. Mixtures of various synthetic lubricants should also be avoided, as the different types of synthetics are not always compatible.

It is important to know the compatibility of some common types of synthetic lubricants with mineral oil-based lubricants. It was found that the mixture of mineral oil and synthetic fluids made from alkylbenzenes (AB) and polyalphaolefins (PAO) is safe; these fluids are compatible [19]; the compatibility of mineral oil with diesters is considered to be good, but with polyglycols it is poor, and it is fair with phosphate esters and polyolesters (POE).

4.2.2.2 Thickeners

An important component of grease is a thickening agent whose properties define the grease consistency [14,20]. Detailed information on the study of various thickener systems' compatibility is given in refs. [21,22]. [Table 4.6](#) presents the latest and most complete and updated grease incompatibility chart. Usually, substantial softening occurs when mixed greases are made with incompatible thickeners. This is especially dangerous since softened grease can run out, particularly in vertical applications.

TABLE 4.6
Grease Incompatibility Chart

	Aluminum Complex	Barium Complex	Calcium Stearate	Calcium 12-Hydroxy	Calcium Complex	Calcium Sulfonate Complex	Lithium Stearate	Lithium 12-Hydroxy	Lithium Complex	Sodium	Clay (Nonsoap)	Polyurea	Polyurea Shear (Stable)
Aluminum Complex	—	I	I	C	I	B	I	I	B	I	I	I	C
Barium Complex	I	—	I	C	I	C	I	I	I	I	I	I	B
Calcium Stearate	I	I	—	C	I	C	C	B	C	I	C	I	C
Calcium 12-Hydroxy	C	C	C	—	B	B	C	C	C	I	C	I	C
Calcium Complex	I	I	I	B	—	I	I	I	C	I	I	C	C
Calcium Sulfonate Complex	B	C	C	B	I	—	B	B	C	I	I	I	C
Lithium Stearate	I	I	C	C	I	B	—	C	C	I	I	I	C
Lithium 12-Hydroxy	I	I	B	C	I	B	C	—	C	I	I	I	C
Lithium Complex	B	I	C	C	C	C	C	C	—	B	I	I	C
Sodium	I	I	I	I	I	I	B	I	B	—	I	I	I
Clay (Nonsoap)	I	I	C	C	I	I	I	I	I	I	—	I	B
Polyurea	I	I	I	I	C	I	I	I	I	I	I	—	C
Polyurea Shear (Stable)	C	B	C	C	C	C	C	C	C	C	B	C	—

Note: Relative Compatibility Rating: C = Compatible; I = Incompatible; B = Borderline.

However, lithium grease hardens in some mixtures, as do some clay mixtures. Barium grease blends look like grease on the bottom and oil on the top; mixing may cause the second grease to liquefy, while the barium remains intact. The final determination of compatibility comes with proper testing of greases in the application for key performance properties [21,22–24].

4.2.2.3 Additives

Very often the cause of incompatibility is a chemical reaction between different types of additives, and grease may have up to a dozen different chemicals added to the base oil to maintain the properties of grease and improve its lubricating abilities [25].

As an example, oils incompatibility may occur if one oil contains an acidic additive and another oil has an alkaline additive, which will neutralize each other if these two oils are mixed. For some oils, such a reaction occurs in the presence of water. Raising the temperature speeds up the reaction. Different fatty acids and/or additive packages affect the compatibility.

Combining greases of different base oils can produce a fluid component that will not provide a continuous lubrication film. Additives can be diluted when greases with different additives are mixed. Mixed greases may become less resistant to heat or have lower shear stability. If a new brand of grease must be introduced, then the component part should be disassembled and thoroughly cleaned to remove all of the old grease. If this is not practical, the new grease should be injected until all traces of the prior product are flushed out.

4.3 LUBRICANT WORKING TEMPERATURE LIMITS AND STORAGE

4.3.1 LUBRICANT WORKING TEMPERATURE

Lubricants are used for the protection of electrical and mechanical parts from corrosion, because they reduce the ingress of corrosive gases on the contact metals or through pores to react with the substrate metal. Application of a lubricant reduces the possibility of electric contact failure due to insulated particulates such as dust or wear fragments of tarnished films, which may deposit on the contact area.

On the other hand, grease is also exposed to many environmental factors that cause contamination and oxidation of the grease. When the grease oxidizes, it usually darkens; there is a build-up of acidic oxidation products. These products can have a destructive effect on the thickener, causing softening, oil bleeding, and leakage.

Because grease does not conduct heat easily, serious oxidation can begin at a hot point and spread slowly through the grease. This produces carbonization and progressive hardening or crust formation [26]. When time in service increases and temperature changes, lubricants may degrade through oxidation or polymerization, forming insulating films.

4.3.1.1 Temperature Limits

Thermal limitations, both high and low, represent the major factors of many lubricants' durability. At low temperatures, many lubricants appear to solidify, developing

high-shear-strength films, and leading to high CR. Some lubricants are susceptible to cracking due to long-term exposure to high temperature [27].

The temperature limits for the use of greases are determined by the drop point, oxidation, and stiffening at low temperatures.

4.3.1.2 Maximum Temperature

Grease has a maximum temperature up to which it can be safely used. The higher the temperature to which grease is exposed, the higher the rate of oxidation. For most greases, it is observed that when it is heated, the grease undergoes a gradual change in consistency until a certain critical temperature is reached. At this point, the gel structure breaks down and the whole grease turns liquid. This critical temperature is called the drop point. When grease is heated above its drop point and then allowed to cool, it usually does not fully regain its grease-like consistency and its subsequent performance will be unsatisfactory. At no time should the drop point be exceeded.

4.3.1.3 Minimum Temperature

This is the point where the grease becomes too hard for the bearings or other greased components to be used. Again, the base oil of the grease determines the minimum temperature. Obviously, the base oil of the grease for low-temperature service must be made from oils having a low viscosity at that temperature. While choosing the best grease for a specific application, all thermal factors should be considered, including the environment, application conditions and working thermal range of the grease.

4.3.2 LUBRICANT STORAGE CONDITIONS AND SHELF LIFE

Oxidation occurs in all oils and greases that are in contact with air, including stored lubricants. The base oil and additive combination affects the rate of oxidation, and the presence of the thickener in grease can increase the degradation rate. But the environmental and storage conditions have the greatest influence on the rate at which the lubricant degrades [28].

The storage environment greatly affects the shelf life of lubricants and greases [29]. There are several important storage conditions that may greatly accelerate lubricant deterioration:

Temperature: Both high heat ($>45^{\circ}\text{C}$) and extreme cold ($<-20^{\circ}\text{C}$) can affect the lubricant stability. Heating increases the rate of oil oxidation, which may lead to the formation of deposits and an increase of viscosity. Cold can result in wax and possible sediment formation. In addition, alternating exposures to heat and cold may result in air being drawn into drums, which may result in moisture contamination. A temperature range of -20°C to 45°C (-4°F to 113°F) is acceptable for the storage of most of the lubricating oils and greases. Ideally, the temperature range for storage should be $0-25^{\circ}\text{C}$ ($32-77^{\circ}\text{F}$).

Light: Light may change the color and appearance of lubricants. Lubricants should be kept in their original metal or plastic containers.

Water: Water may react with some lubricant additives, sometimes forming insoluble matter. Water can also promote microbial growth at the oil/water interface. Lubricants should be stored in a dry location, preferably inside.

Particulate contamination: Drums and pails should not be stored in areas where there is a high level of airborne particles. This is especially important when a partially used container is stored.

Atmospheric contamination: Oxygen and carbon dioxide can react with lubricants and affect their viscosity and consistency. Keeping lubricant containers sealed until the product is needed is the best protection.

Oil separation: Oil will naturally separate from most greases. Temperatures in excess of 45°C (113°F) can accelerate oil separation. If grease is removed from a drum or pail, the surface of the remaining grease should be smoothed to prevent oil separation into the cavity.

Storage condition affecting greases: Grease properties can change during storage depending on the type of thickener, its concentration, the base fluids, and the additives used.

Lubricant shelf life: Limitations are not formalized into a standard yet. But there is some guidance coming from major lubricant manufacturers with general recommendation for lubricant shelf life.

As an example, some grease manufacturers [29,30] estimated the shelf life of base and lubricating oils and greases in unopened containers to be 5 years for base oils, mineral or synthetic lubricating oils and greases. A limited shelf life (2 years) is listed for rust preventives and open gear lubricants [29,30]. However, for some advanced greases the shelf life is longer (6 years in any container). If oil is observed on top of the grease, it should be remixed back into the top inch (2.5 cm) of the grease prior to use. Horizontally stored grease cartridges may bleed minor amounts of oil. This may make the container cosmetically unpleasing, but the grease remains suitable for use.

4.4 LUBRICATION OF ELECTRICAL CONTACTS

Application of lubricants is an effective way to protect an electrical connection from the factors that cause an increase of electrical resistance. In electrical and electronic devices, there are benefits from applying lubricants to the electrical contacts. The type and function of the contact define the lubricant required. By definition, an electrical contact is a combination of two surfaces held together by force with the passage of current, voltage, or signals [31].

Electrical contacts in very-high-power circuits with currents up to mega-amperes do not have much in common with electronic circuits, with currents as small as micro-amperes [32]. Power dissipation ranges from dozens of watts to a tenth of a watt [33]. The force holding the contact surfaces together may vary from low values ($P < 0.2$ N) to high (several tens of N) [34]. Many factors can lead to the degradation of contact surfaces. Sliding and rolling contacts constantly move against each other and the surfaces degrade due to friction and wear debris. Static or wiping contacts experience vibration while the current is passing through, which destroys the plated coating (fretting).

Nonconductive deposits on the contact surfaces formed due to various types of corrosion (atmospheric and galvanic) lead to a rise in CR. A properly chosen lubricant may slow down these processes without interfering with the electrical resistance of the contact.

4.4.1 PRINCIPLES OF CONTACT LUBRICATION

The general principle of lubrication is to use a substance that protects an electrical connection from degradation and increase in electrical resistance. The positive effect of lubrication can be achieved only if the product is carefully chosen based on conformity between lubricant properties and the conditions of application, such as the contact design, load, heat dissipation, and environment. The long-term effect could be negative if the lubricant cannot withstand the service conditions and degrades itself, inducing an additional cause of contact deterioration.

Lubricant function depends on application. In separable connectors, it reduces friction during installation, minimizes mechanical wear during connector service, and slows down the destructive effect of fretting corrosion. The lubricant in a permanent electrical connection blocks the access of corrosive gases or particulate material to the interfaces of the conductors [33]. An important factor in choosing the right lubrication product is the environment in which a particular electronic or electrical apparatus is to function. Various environmental factors and their combinations are aggressive towards traditional metals used in electrical contacts (copper, aluminum, and various alloys) and their coatings (silver, tin, nickel, gold, etc.), but they may also be harmful to lubrication materials.

The most important and general roles of the lubrication of electrical contacts are: protection from environmental and galvanic corrosion, wear/friction, and fretting corrosion. All known types of lubricants (among them mineral and synthetic oils and greases, solids, and dispersions) [35–37] have been tested and applied to electrical contacts. Compared with other lubricants, polymeric ethers such as PPE and Perfluorinated Polyether (PFPE) have better characteristics: stability at high temperatures and a very low vapor pressure. Above all, PPEs demonstrate an ability to remain at the contact point without migrating. Polymeric ethers also provide a high degree of protection from atmospheric contaminants for connectors [38,39].

4.4.2 CHOICE OF LUBRICANTS BASED ON DESIGN AND CONTACT/PLATING MATERIALS

A summary of the last 20 years of lubricants testing for their application to various types of electrical contacts made of different types of materials is presented in [Tables 4.7](#) through 4.9. Lubricants evaluation was performed on the basis of their effect on the performance and stability of the contacts, protection from atmospheric and fretting corrosion, reduction of friction and wear, and their ability to withstand degradation under the contact working conditions. For example, many lubricants have been tested on a bolted joint under various current cycling conditions and fretting to determine the spreading tendency, stability to thermal degradation, stability to UV radiation and field conditions, as well their ability to protect the contact against fretting [40].

In a series of tests [71] on tin- and silver-plated stationary parts, it was shown that lubricants generally reduced the severity of wear and tendency for fretting corrosion (thereby reducing the CR), and gave no increase of CR or any other negative effect. It was also demonstrated in modeling experiments that lubrication might be effective in restoring a degraded system [52].

TABLE 4.7**Lubricants for Electronic Separable, Low Load, Low-Power Connections Made of Copper**

Base Metal/Plating	Base Metal/Plating of Mating Part	Lubricants Tested	Test	Ref.
Cu/Sn	Same	PPE, POE, Esters, PFAE, PAG, silicones, hydrocarbon oils (mineral and synthetic), chlorofluorocarbons	Volatility, fretting, spreading, wetting, gum formation	[41]
Cu/Sn	Same	Chlorophenyl silicone (best), phenylmethyl silicone and methyl alkyl silicone systems	Fretting, high T , oxidation, reactivity	[42]
Cu/Ag	None	Stearic acid	Corrosion	[43]
Cu/Au	Same	Synthetic paraffin mixture, wax mixture, synthetic paraffin with PPE, PPE	Resistivity, friction, wear, corrosion, dust	[44]
Cu/Au	Same	Liquid lubricants, wax lubricants ^b	Dust	[45]
Cu/Au or Ag or Sn	Same	Liquid lubricants: paraffin oil with FA ester, five-ring PPE	Corrosion, dust	[46]
Cu/Sn	Cu/Sn	PAO	Fretting, oxidation	[47]
Cu/Au or 60Pd40Au or Ni inlay	Brass/Au/Pd/Ni ^a or Au/Ni ^a	PPE, mineral oil, POE	Friction, wear	[48]
Cu/Au flash/Pd/Ni ^a	Phosphor bronze/Au/Ni ^a	POE, five-ring PPE, six-ring PPE, six-ring PPE with MCW, different additives	Thermal aging, corrosion	[49]
Cu/Au	Pd/none or Au	Mineral oil, PPE	Wear, fretting, resistance	[50]

Source: Chudnovsky B. Lubrication of electrical contacts, *Proceedings of the fifty first IEEE Holm Conference on Electrical Contacts*, Chicago, IL, 2005, pp. 107–114. © 2005, IEEE.

Abbreviations: FA, fatty acid; MCW, microcrystalline wax; PAO, polyalphaolefin; PAG, polyalkylene glycol; PFAE, perfluoropolyalkylether; PFPE, perfluoropolyether; POE, polyolester; PPE, polyphenyl ether.

^a Ni underplating.

^b The product performed unsatisfactory in the testing.

However, it was confirmed that lubrication delays but does not totally prevent fretting corrosion [53,83]. After prolonged exposure to fretting, the beneficial effect of lubrication may be lost. Further conduction is impeded by the formation of a layer composed of nonconducting wear debris and lubricant [64].

TABLE 4.8
Lubricants for Electronic Separable, Low Load, Low-Power Connections
Made of Copper Alloys

Base Metal	Base Metal/Plating of Mating Part	Lubricants Tested	Type of Testing	Ref.
Cu alloys/Au	Brass/Au/Pd/Ni ^a or Au/Ni ^a	PPE, Mineral oil, POE	Wear, friction	[50]
Cu alloys/Au–Ag–Pt or Au/Pd–Ag inlays	Phosphor bronze/Ni or Au	Five-ring PPE	Corrosion	[51]
Brass/Bare, Au, Au/Ni ^a , Pd/Ni ^a , Sn	Same	PAO with FA, Liquid paraffin with FA ester, paraffin wax with FA, alkyl mercaptan with wax, and five-ring PPE	Friction, resistance	[52]
Brass/None or Au/Ni ^a or Sn–Pb	Same	Six-ring PPE, petroleum jelly	Resistance, wiping	[53]
Brass C26000/Sn–Pb/Cu ^a	Same	Five-ring PPE, PAG (liquid and grease)	Fretting	[54]
N/A (socket)/Au/Ni ^a	Ne–Fe alloy/Sn/Cu ^a	Mil-L-87177 grease ^c	Fretting	[55]
Cu–Ni–Sn Alloy CA725/Au flash/Pd/Ni* or Au/Ni ^a	Same	Six-ring PPE, six-ring PPE mixed with MCW	Corrosion, fretting	[56]
Cu–Ni–Sn Alloy CA725 Au flash/Pd/Ni ^a or Au/Ni ^a	Clad Au–Pd–Ag alloy/none	Six-ring PPE	Friction, wear	[57]
Phosphor bronze/None or Sn–Pb	Same	Six-ring PPE, petroleum jelly	Resistance, wiping	[53]
Phosphor bronze/Au/Ni ^a	Same	PPE (thermal aging)	Thermal aging	[58]
Phosphor bronze/Au/Ni ^a	Same	Water soluble lubricant, paraffin oil with FA ester, five-ring PPE	Corrosion, wear, fretting	[59]
Phosphor Bronze/Au/Ni ^a	Same	FxHy, FxOHy, SH-PFPE	Corrosion	[60]
Copper alloys/Au/Ni ^a or Diffuse Au Alloy or Sn or Ag/Ni ^a	Same	PFPE silicone grease, Stabilant 22 ^{b,c}	Resistance, oxidation	[61]
CuSn ₄ bronze/Sn	Same	PFPE linear low viscosity and branched low and high viscosity	Friction, wear, fretting	[62,63]
Au–Ni clad/None, Au flash	Same	Six-ring PPE	Wear	[64]

Source: Chudnovsky B. Lubrication of electrical contacts, *Proceedings of the fifty first IEEE Holm Conference on Electrical Contacts*, Chicago, IL, 2005, pp. 107–114. © 2005, IEEE.

Abbreviations: FA, fatty acid; FxHy, fluorinated thiol; FxOHy, fluorinated ether thiol; PAG, polyalkylene glycol; PAO, polyalphaolefin; PFPE, perfluoropolyether; POE, polyolester; PPE, polyphenyl ether; SH, PFPE—PFPE with sulfur end groups.

^a Ni underplating.

^b The product performed unsatisfactory in the testing.

^c Commercial product with proprietary chemical composition.

TABLE 4.9**Lubricants for Permanent High-Load Electrical Connections Made of Al, Cu, and Ag Alloys**

Base Metal/ Plating	Base Metal of Mating Part	Lubricants Tested	Test	Ref.
Bare Al	Same	Molycote G-n ^c , silicone vacuum grease, Penetrox ^c , petroleum jelly, Aluma Shield ^c , Kearnalex ^c inhibitor, Contactal ^c , Fargolene ^c , Alcan ^c jointing compound	High <i>T</i> , consistency, resistance, fretting	[40,65]
Al/Ni	Same	Petroleum jelly	Fretting	[66]
Bare Al	Cu	Silicone, Penetrox ^c , petroleum jelly, NO-OX-ID ⁺ , Kopr-Shield ^c , Nikkei ^c , Contactal ^c	High <i>T</i> , spreading, fretting	[67]
Bare Al	Same	Stearic acid ^b	Friction, wear	[68]
Bare Al	Same	MoS ₂ grease ^b	Fretting	[69]
Bare Cu				
Bare Al	Bare Cu or Cu/Sn	Mobil grease ^c , Belray ^c , Convoy ^c , Shell Darina ^c , Fomblin ^c , Penetrox ^c , Felpro ^c Ni Antiseize, GEC M111 ^c , Kopr-Shield ^c	High <i>T</i> , UV, spreading, fretting	[70]
Bare Al	Bare Al	PFPE greases, Superlube ^c grease (Teflon), DuPont Krytox ^c , PFPE grease with Cu additive	High <i>T</i> , resistance, fretting	[71]
Bare Cu	Bare Cu or Cu/Sn			
Bare Al	Same	Teflon, PFPE/PTFE, PFAE/PFPE	High <i>T</i> , UV	[72]
Cu/Ag or Sn or Ag/Ni ^a	Same	Li synthetic grease	Resistance, adhesive and fretting wear, friction, cold welding, oxidation	[73–75]
Cu/Sn	Al-Mg alloy/bare or Ni; Al/Ni and bare Cu	Commercial grease TSIATIM-222 ^c with or without Ni powder	High <i>T</i> , oxidation	[76]
Cu (plating unknown)	Same	Li-soap grease, metalless grease, Silicate based grease ^b	Wiping and arcing effects	[77]
Bare Cu	Same	Li-stearate PAO grease with and without corrosion inhibitor	High <i>T</i> , oxidation	[78]
Cu (OLTC contacts)/Ag	Same	Silver iodide	Friction, wear	[79]
Cu (sliding contacts)/Sn or Ag or bare	Same	Naphtenic mineral oil	High <i>T</i> , Friction, wear	[80]

continued

TABLE 4.9 (continued)
Lubricants for Permanent High-Load Electrical Connections Made of Al, Cu, and Ag Alloys

Base Metal/ Plating	Base Metal of Mating Part	Lubricants Tested	Test	Ref.
Ag-CdO/AgP or AgCd brazing alloys	Same	Graphite-S, silicone paste, MoS ₂ grease, Na-soap mineral grease, mineral oil	Contamination	[81]
Ag-CdO rivet	Cu blade	Silicone ^b	Contamination	[82]

Source: Chudnovsky B. Lubrication of electrical contacts, *Proceedings of the fifty first IEEE Holm Conference on Electrical Contacts*, Chicago, IL, 2005, pp. 107–114 © 2005, IEEE.

Abbreviations: PAO, polyalphaolefin; PFAE, perfluoropolyalkylether; PFPE, perfluorinated polyether; PTFE, polytetrafluoroethylene.

- ^a Ni underplating.
- ^b The product performed unsatisfactory in the testing.
- ^c Commercial product with proprietary chemical composition.

Fretting tests showed that at low loads none of the lubricants could protect the contact zone against fretting, but increasing the contact loads significantly improved the lubricant’s protective ability. This improvement was observed in copper-to-copper and copper-to-tin plated copper contacts, but not in the case of aluminum fretting against aluminum, since none of the lubricants tested had the ability to suppress the effect of fretting.

The results of recent cycling tests showed that all lubricants had a beneficial effect on the performance of bolted joints as manifested by stable operation [69]. Having a lubricated contact surface reduces the friction force and the wear of gold plating during sliding or micromotion. In contactor applications, it appears that the insertion and withdrawal force can be reduced to as low as 20% of the nonlubricated surface [46]. Detailed information on the requirements, methods of application, and examples of widely used fluids, greases, and solid lubricants may be found in [55].

4.4.3 LUBRICATION AS PROTECTION FROM FRETTING CORROSION, MECHANICAL WEAR, AND FRICTION

The practice of contact lubrication is as old as connectors themselves [34]. Early testing demonstrated that lubrication is essential to achieve low and repeatable coefficients of *friction*, whether using inlay or electroplated material. The effectiveness of lubricants in stabilizing the CR, in wear reduction, and in retarding the rate of oxide formation by shielding the surface from air appears to be not strongly dependent on their composition and viscosity, and both fluids and greases are of value [50].

Some lubricants (polyphenyl ethers) appeared to be more effective than others in preventing adhesive wear, particularly when they are thick [48,50]. Mineral oil and POE are not very effective in reducing the coefficient of friction, probably due to their lower viscosity [48].

The results of the multiple *fretting* tests (Tables 4.7 and 4.8) showed that many contact compounds have beneficial effects on the CR behavior. Application of a lubricant helps to decrease CR fluctuations and to lower the CR.

The efficacy of a compound in reducing the fretting damage depends on the ability of a particular compound to flow back over freshly exposed metal pushed aside by the contact slip [40]. This ability depends on the lubricant's initial consistency and the change in consistency [84].

4.4.4 LUBRICATION AS PROTECTION FROM CORROSION

Corrosive factors in the environment are all those that are chemically aggressive towards contact materials and plating and produce a nonconductive deposit on the contacts (corrosive gases and vapors), or the environmental factors that accelerate corrosion (temperature extremes and humidity). An additional contaminating factor is dust. Another phenomenon that leads to contact degradation is galvanic corrosion between dissimilar metals.

The benefits of applying lubricant for corrosion protection are not as well understood as its application in the reduction of friction and wear. For many years, the benefits of using lubricant for corrosion inhibition were overlooked because prospective users were skeptical that a nonconductive substance could be applied onto contacts without interfering with the conduction [85].

It is important to consider all the factors that may result in the negative effect of lubrication if the chosen product deteriorates while exposed to a high-temperature environment, migrates or leaks out, or collects dust [86]. The choice of lubricant for corrosion protection should be based on thorough qualification of the product for survival in long-term use and the ability of such products to provide friction and wear reduction. Very few lubricants have been identified that provide exceptional long-term corrosion protection and yet do not produce any adverse effect on connector surfaces.

Field testing showed that lubricated surfaces collect and retain dust. Sliding electric contact experiments show that, in dusty environments, liquid lubricants appear to perform better than wax lubricants. Experimental and theoretical analyses indicated that the high permittivity of the lubricants plays an important role in attracting dust [87].

The mixture of dust particles and wax could be very harmful to the contact, especially under low normal force. It was found that liquid lubricants with lower permittivity provide much better contact behavior in dusty environments, either for sliding electric contacts or static contact applications [45]. There was little indication of any adverse electrical effects for the best lubricants. It appears that while dust may be retained by the lubricant, it is also effectively dispersed away from the mating interface during wipe or micromotion events. The tests found that the beneficial effects of corrosion inhibition by the lubricant overshadow any negative effects due to dust [46,88].

An example of a lubricant that proved useful for corrosion protection for connectors made or plated with precious metals is six-ring PPE or its mixture with microcrystalline wax, although the wax content should be controlled [56,64,83]. Multiple products, such as synthetic soap greases and other commercial greases, have been tested and proven useful for bolted contact application [40,67,70,71,76].

Galvanic or bimetallic corrosion is another phenomenon that is harmful to the contact surfaces. Whenever dissimilar metals are in the presence of an electrolyte, a difference in electric potential develops. When these metals are in contact, an electrical current flows, as in the case of any short-circuited electric cell. This electrolytic action causes an attack on the anodic metal, leaving the cathodic metal unharmed. The extent of the attack depends on the relative position of two metals in contact in the electrolytic potential series.

Galvanic corrosion is common with aluminum-to-copper connections, since copper and aluminum are quite far apart in the series, copper being cathodic and aluminum being anodic. Hence, when aluminum and copper are in contact in an electrolyte, the aluminum may be expected to be severely attacked.

Some products, such as petrolatum-type compounds containing zinc dust, effectively protect contacts made of dissimilar metals from galvanic corrosion [89]. However, some lubricants may induce galvanic corrosion; therefore the products for this application should be chosen very carefully. For example, graphite, which has a noble potential, may lead to severe galvanic corrosion of copper alloys in a saline environment [23].

Multiple studies showed that lubrication reduces the ingress of corrosive gases on the contact metals or through pores (which is particularly important for thin gold plating) to react with the substrate metal. Application of lubricant reduces the possibility of electric contact failure from insulated particulates such as dust or wear fragments of tarnished films, which may deposit on the contact area.

However, application conditions of connectors (such as electric current, normal force, the number of contact pairs within one housing, sliding, micro-motion, etc.) and environmental conditions (such as humidity, temperature, corrosive gases, dust, etc.) are very complicated. That is the reason why it is almost impossible to choose just one kind of lubricant to fulfill all the requirements and to match all the above conditions. Unfortunately, there is no such thing as a “universal lubricant.”

4.4.5 DURABILITY OF LUBRICANTS

The purpose of lubrication is to improve electrical contact functionality and prolong service life. Therefore, it is important to ensure that none of the lubrication product properties would work against this purpose. Lubrication products should not deteriorate or contaminate the contact surfaces for a predetermined period of time within the range of application conditions. A lubricant should remain stable in sufficient quantities at the contact interface to perform its intended function throughout life.

Lubricants applied to the contact surfaces are exposed to four major temperature-sensitive aging mechanisms: evaporation, surface migration, polymerization, and degradation [41,83,86,90]. With time and temperature, lubricants may degrade by oxidation or polymerization, forming insulating films or gums [41].

Due to evaporation and mechanical loss, a thin coating of a contact lubricant can disappear from surfaces. Mechanical loss is its physical removal as a result of sliding, such as by wear debris that carries it away. Evaporative loss will occur if the lubricant has a significant vapor pressure and is important at elevated temperatures, particularly with the fluid lubricants [41,83].

When a lubricant disappears from the contact interface by evaporating or spreading, the contact is exposed to failure by wear or by corrosion. Several material properties, such as viscosity, surface tension, vapor pressure, and thermal stability, are important in selecting the proper lubricant for contact application.

Thermal limitations, both high and low, represent major factors in the durability of many lubricants. At low temperatures, many lubricants appear to solidify, developing high-shear-strength films, and leading to high CR [88]. Some lubricants are susceptible to cracking due to long-term exposure to high temperature [71].

Lubricants may degrade due to chemical reaction with the atmosphere and may also polymerize when heated in the presence of a copper-based alloy [91]. Copper is known to degrade polymers through catalytic-enhanced oxidation, so grease would undergo changes in contact with copper at higher application temperatures, which in turn induces copper corrosion. Applying grease with a copper corrosion inhibitor to copper contacts at high temperature may significantly decrease lubricant-induced copper corrosion [78].

Because of their composition, some lubricants, such as greases with silicate thickener, have undesirable properties when applied to electrical contacts [77,82]. Silicate as a high-temperature grease thickener may pose problems if entrapped under the contact. Near an arc, splattering effects can occur, coating the surface with a nonconductive layer. Particles may also be fused together by the arc. Even with lower voltages, arcing will occur if the inductance in the circuit is significant. Silicon compounds, both inorganic and organic, are detrimental contaminants for arcing electrical contacts [82]. Any refractory material in the area of arcing can present similar problems.

4.5 PRACTICAL LUBRICATION

4.5.1 PERIODIC LUBRICATION MAINTENANCE OF ELECTRICAL POWER EQUIPMENT

During periodic lubrication of electrical power equipment it is important to follow the directions usually given in manufacturers' user manuals. However, there are several rules that are the same no matter which type of equipment is maintained.

4.5.1.1 Cleaning

Before periodical lubrication, all traces of the old lubricant must be removed from surfaces by the use of commercial cleaners: kerosene, mineral spirits, and so on. To loosen the old lubricant, soak the disconnected parts in solvent. To remove contamination from the part, the solvent can be agitated or flushed through the part. If the part cannot be removed, adding oil could be helpful. It is important to use the same type of oil that was used as a base in grease to be removed. To speed the process of cleaning soft bristled brushes may be used. After removal from the solvent, parts should be carefully dried and relubricated as soon as possible.

4.5.1.2 Penetrating Oil

Penetrating oil should not be used as a lubricant in electrical equipment. Penetrating oil is not designed for lubrication; it always contains solvent(s). Penetrating oil works only briefly, is contaminated easily, and may change into a viscous mess. In

comparison with grease, penetrating oil has much lower viscosity (flows easily), very low boiling temperature and high vapor pressure at ambient temperature. It will leak out under gravity or centrifugal action, leaving the lubricated parts dry. Penetrating oil will attack, dissolve, and wash out factory-installed lubricants and hasten failure. Most penetrating oils or aerosols are flammable and should not be applied in areas where sparks or arcing may occur. Penetrating oils are recommended only for rust removal and ease of part disconnection.

4.5.1.3 Lubrication in Field

For lubrication in field when disassembling is not supposed to be done, low- or medium-viscosity oil is recommended. In some cases, lubrication characteristics of petroleum oils may be improved by adding a stable dispersion of molybdenum disulfide in a premium mineral oil, which is available from some major manufacturers. These materials may extend lubricant and gears life, reduce metal-to-metal contact, lower friction, and so on, and may also be used as lubricant concentrates.

4.5.1.4 Troubleshooting Lubrication

A procedure for lubrication troubleshooting of electrical equipment such as CBs is usually recommended by the manufacturer. If the manufacturer's troubleshooting procedure is unavailable or ineffective, one can consider using diagnostic instruments, which can measure the trip time, force, resistance, vibration, and so on. Certain profiles will indicate lubrication problems. If this type of diagnostic is not available, but slow operation is encountered, it may be caused by inadequate lubrication.

When analyzing the lubrication problem, it is important to identify a symptom that is specific to the lubrication fault: excessive leakage of the lubricant, overheating, wear and scoring, and so on. The problem may be due to manifold reasons: it could be that incorrect lubrication product was used or too little of the lubricant was applied. Presence of water in the system could dramatically change the lubricant's properties.

To take corrective actions, it is important to determine what kind of product was used in the previous maintenance and what the properties of the used product are. The final step would be to define a proper product and relubricate the apparatus accordingly to the OEM recommendations.

4.5.2 GENERAL LUBRICATION RECOMMENDATIONS FOR ELECTRICAL EQUIPMENT

4.5.2.1 Choice of Lubricants

Depending on application, manufacturers may specify various greases, which have been thoroughly tested for a specific application. Usually, each manufacturer lists all greases which should be applied at specific points and the greases are different for the mechanical and electrical parts. These greases are applied during assembly of the original equipment and it is always recommended to use the same or a similar lubrication product for relubrication, which will guarantee that it will perform properly in service.

4.5.2.2 OEM Specifications

Lubrication should be performed according to the manufacturer if an alternative lubrication practice is not implemented. If either the lubrication product is obsolete or the electrical manufacturer is no longer available in the market, then OEM's lubrication specification cannot be followed. In such a case, the lubricant to use could be chosen strictly based on the application and physical properties of the recommended greases.

4.5.2.3 Change of Lubrication Product

Any change of lubrication product often involves testing and must be performed under the supervision of engineering. The engineering staff has to specify what type and brand of grease or oil should be applied during maintenance or overhaul of a particular piece of equipment. Any failure of equipment which might be caused by insufficient lubrication must be analyzed. Any experience has to be used to improve the lubrication technique and lubricant choice.

4.5.2.3.1 Lubricants Availability

Any lubricant specified or chosen for lubrication must be readily available locally and nationwide. The user should keep a sufficient supply of greases in properly organized lubrication storage together with the products' MSDS and Technical Data Sheets.

4.5.2.4 Lubrication of Electrical Contacts

Electrical contacts should not be lubricated with metal filled lubricants unless tested and proved to be effective in the long term. Many can accelerate corrosion, create conductive paths and eventually cause failure. The general rule is to avoid graphite, molybdenum disulfide (Moly), or PTFE (Teflon®) lubricants for electrical contacts, because they could cause a rise in resistance after multiple operations [92,93]. For most switches and the ones that operate infrequently, to keep the contact just clean and dry with no lubricant might be a viable option. Main and arcing contacts should never be lubricated. Proper lubrication practices for various types of LV and MV power distribution equipment are presented in multiple papers [6,7,94–100] and OEM's Data Bulletins [101,102] available for customers.

4.5.2.5 Application of Lubricants

The following rules are general and can be applied to all maintenance lubrication procedures:

1. Use the factory-recommended lubricants whenever it is possible.
2. Do not use petroleum lubricants in areas with extreme cold temperatures. Petroleum oil greases get thick and hard and do not function properly below -20°C (0°F).
3. Do not apply metal filled lubricants to electrical contacts. They can accelerate corrosion and create conductive paths and eventually failure.
4. Do not apply silicone lubricants to silicone rubber, fluorosilicone lubricants to fluorosilicone rubber, and petroleum lubricants to rubber. They are incompatible.

5. Do not use penetrating oils for lubrication of CBs; they work only briefly and tend to become thick and sticky with age.
6. Do not use flammable penetrating oils or aerosols in areas where arcing or sparks may occur.
7. Do not over-lubricate.
8. Avoid mixing lubricants.

4.6 LUBRICATION FAILURE MODES

4.6.1 CAUSES OF LUBRICATION FAILURE

The term “lubrication failure” includes different issues, such as an inadequate amount of lubricant applied or no lubricant at all, improper product chosen for lubrication, contamination and aging of the lubricant because of ambient conditions, and so on. It is found that as many as 60–80% of all bearing failures are lubrication related, whether it be poor lubricant selection, poor application, lubricant contamination, or lubricant degradation. Many components are failing early because lubrication best practices have not been established [103].

When failure happens, a thorough examination of the lubricant’s properties is required in many cases, as well as an analysis of the amount of lubricant applied, where it was applied, and the operating conditions of the mechanical or electrical parts. All these factors contribute to the damage caused by lubrication failure, which led to excessive wear and corrosion of parts and the failure of the electromechanical unit to perform properly [92,104].

The lubricant play a very important role. Lubricants separate the working surfaces preventing metal-to-metal contact, and reduce friction and wear. Lubricants protect against corrosion, exclude contaminants, and dissipate heat. Reducing friction and corrosion through proper lubrication is equally important for electromechanical equipment with moving parts and for nonrotating apparatus.

A power switching device is an example of such apparatus. Its operation depends upon friction-free movement of many different mechanical components, usually through only a short distance or slight angle, often exposed to moisture and environmental contamination, as well as to long periods of idleness during which the lubricant deteriorates and materials corrode. CBs, which must operate quickly and reliably during unpredictable emergencies, are especially vulnerable [105].

In this chapter different lubrication failure modes will be summarized. Lubrication failure may affect the functionality and performance of various parts of electromechanical apparatus. The role of the proper choice of the lubrication products, terms and procedures is discussed in relation to operational and environmental parameters. Lubrication failure mode describes the specific causes of failure associated with a component or functionality of a process. The failure may be caused by lubrication procedures, terms or products. For example, the mode for circuit breaker (component) failure to open (functionality of a process) is lack of lubrication.

A number of different factors may affect lubricant performance. It is important to choose the correct product for each particular application, which means that many factors should be considered, such as operational and thermal temperature

ranges, mechanical load (pressure) on the areas where the lubricant is applied, presence of moisture, possible contamination (particulate matter, dust, corrosive gases), and so on. Accordingly, the lubricant properties (working temperature range, moisture content, and presence corrosive chemical components) should comply with the application parameters and materials in avoid adversely affecting the units and environment.

Knowledge of the composition of the lubricant is particularly important for its application to electrical contacts, since some additives may affect electrical resistance of conductors. It is also important to apply the right amount of lubricant, because the lack of it or an excessive amount may increase the friction and wear of the parts or lead to contamination of other parts of the unit with lubricants.

4.6.2 WRONG LUBRICANT FOR APPLICATION

The lubricant choice for a specific application is determined by matching the machinery design and operating conditions with the desired lubricant characteristics [106]. Grease, and not oil, is generally used for the lubrication of CBs, equipment that do not run continuously and whose parts can stay inactive for long periods of time. One reason for the preference of grease is because CBs are not easily accessible for frequent lubrication, and high-quality greases can lubricate the components for extended periods of time without replenishing. Grease, and not oil, should be chosen for lubrication of most parts of CBs, since they can be exposed to high temperatures, shock loads or high speeds under heavy load. In the application to CBs, choosing the right lubricant is a very important step.

4.6.3 THERMAL LIMITATIONS

Thermal limitations, both high and low, represent major factors in the durability of many lubricants (see Section 4.4.5). At low temperatures, many lubricants appear to solidify, developing high-shear-strength films, and leading to high CR. Some lubricants are susceptible to cracking due to long-term exposure to high temperature. Grease has a maximum temperature at which it can safely be used. This critical temperature is called the *drop* point, the point at which the gel structure breaks down and the whole grease becomes liquid.

When grease is heated above its drop point and then allowed to cool, it usually fails to fully regain its grease-like consistency and its subsequent performance will be unsatisfactory. Accordingly, if the temperature of CB lubricated components in operation is higher than the upper limit of the lubricant working temperature range, it could leak out at high temperatures, which will affect the mechanical performance of the parts or expose them to corrosive environment.

Elevated operating temperature shortens the life of greases. In fact, if a switch-gear operates at temperatures above 70°C (158°F), it cuts grease life by a factor of 1.5 for each 10°C rise [107]. High temperature promotes oxidation and increases oil evaporation rates and oil loss by creep, which accelerate grease drying and shorten grease life. Grease life can be estimated for operating temperatures above 70°C (158°F) with moderate loads and no contamination. This approach is applicable to

fresh industrial greases of Grade 2 consistency with thickeners such as lithium, complex metal soaps, and polyureas.

Other ways to estimate lubricant lifecycles are based on operating conditions and require the application of factors to account for real-life conditions, such as solid contamination, moisture, air, catalytic effect of wear debris, temperature variations in a circulating system, and so on. As the temperature increases, the rate of grease degradation increases. The Arrhenius rule suggests doubling the lubricating oil degradation rate for each 10°C increase in temperature. Synthetic lubricants generally last longer at elevated temperatures than their mineral-oil counterparts.

The base oil of the grease determines the minimum working temperature for the grease. The base oil of the grease for low-temperature service must be made from oils having a low viscosity at that temperature. For example, if the operational temperature of the unit in operation is lower than the lower limit of the lubricant working temperature range, then the lubricant may stiffen at cold temperatures, which could happen in the CBs that are installed outdoors [108].

4.6.4 LUBRICANT COMPOSITION AND WRONG AMOUNT OF LUBRICANT

If the lubricant containing nonconductive solid additives is applied to electrical contact surfaces, it will increase electrical resistance, leading to overheating failures. To avoid such problems, it is important to use both the type and quantity of lubricant specified by the manufacturer, not only at the time of installation, but also during maintenance procedures.

A common misconception among maintenance personnel is that it is better to over-lubricate than to under-lubricate bearings and matching parts. Both methods are undesirable. Under-lubrication risks metal-to-metal contact, and over-lubrication (pushing excessive grease into the cavity) causes heat build-up and friction as the moving elements continuously try to push extra grease out of the way. To ensure that moving parts are not over- or under-lubricated, follow the manufacturer's instructions. This recommendation applies both to grease and oil lubrication. In electrical applications, over-greasing may lead to contamination of the nonconductive parts with grease or oil, which will adversely affect the dielectric properties of the insulating materials.

4.6.5 CONTAMINANTS OR CORROSIVES IN THE LUBRICANT

Although contaminants are sometimes difficult to detect, they often cause lubrication failure in CBs. Dirt, sand, and water are the most common contaminants, but acid and other corrosives also can deteriorate the lubricant (grease and oil). They can dilute the oil film, reducing viscosity, and they can corrode metal surfaces, disrupting the lubrication film and causing erosion, creating thousands of abrasive particles. Moisture contamination increases chemical wear by rusting iron and steel surfaces it also increases the corrosive strength of resident acids attacking copper and lead surfaces [109].

Solid particulate contaminants introduce most damage from the moment they come into contact with the surfaces of rotating parts (bearings). Depending on particle size, they may be seen or felt as grittiness in the lubricant. Particle contamination

primarily affects the lubricant's ability to control friction and wear. By obstructing the separation of moving components and interfering with chemical oil films provided by antiwear and EP additives, particle contamination can substantially increase the rate of abrasion, adhesion, and surface fatigue. The effects of particle contamination are slow and imperceptible.

In fact, the loss of the lubricant's functional ability to reduce wear and friction is often overlooked due to the slowness with which particle contamination affects the system [109]. The best safeguard against contaminants is a clean, dry CB operating environment. If operating circumstances do not permit this environment, select sealed enclosures or shields to keep contaminants out. If humidity is a problem, consider selecting a lubricant with a good rust inhibitor. Harsh environments can sometimes be overcome by increasing the frequency of lubrication maintenance.

4.6.6 ENVIRONMENTAL FACTORS CAUSING GREASE DETERIORATION

Grease is exposed to many environmental factors that cause contamination and oxidation of the grease. These factors are atmospheric oxygen, dust and dirt, high and cold temperatures, and light. Exposure of lubricant to atmospheric oxygen forms gums, resins, and acidic products with viscosity increase. When the grease oxidizes, it usually darkens; there is a build-up of acidic oxidation products. These products can have a destructive effect on the thickener, causing softening, oil bleeding, and leakage. Because grease does not conduct heat easily, severe oxidation can begin at a hot point and spread slowly through the grease. This produces carbonization and progressive hardening or crust formation [105]. To protect the grease from contact with oxygen it is recommended that lubricants containing antioxidant additive be used. Keep the grease in sealed containers [109]. Dirt and dust in the grease increase the rate of wear between bearing surfaces, which also necessitates keeping the lubricants covered or in containers.

Exposure of the grease to high temperatures increases the rate of deterioration, forms gums, resins, and acidic products, and increases oil separation from greases, while the exposure of water-containing materials (e.g., cutting oils and certain fire-resisting hydraulic oils) to cold causes water to separate out. Therefore, it is recommended to keep the storage temperature not higher than 20°C (68°F) and above the freezing point. Light promotes the formation of gums, resins, and acidity in the lubricants; to protect the materials from exposure to light, they should be stored in metal or opaque containers.

With increasing time in service and temperature fluctuations, lubricants may degrade by oxidation or polymerization, forming insulating films. Oxidation occurs in all oils and greases that are in contact with air, including stored lubricants. The base oil and additive combination affects the rate of oxidation, and the presence of a thickener in grease can increase the degradation rate.

If the lubricant was badly degraded or reacted chemically to environmental contaminants, deposits in the form of gum, resin, varnish, sludge, or other deposits could be found in places where the lubricant was applied. Elemental analysis of these residues may help to identify the sources of deterioration and to determine if they were degraded grease additives or thickeners, or environmental contaminants.

Environmental and storage conditions have the strongest influence on the rate at which the lubricant degrades [105]. The storage environment strongly affects the shelf life of lubricants and greases [104]. The characteristics of some greases may change in storage. Grease may bleed, change consistency, or pick up contaminants during storage. Storage conditions that may accelerate lubricant deterioration are given in Section 4.3.

4.6.7 LUBRICANTS' INCOMPATIBILITY

Incompatibility occurs when a mixture of two greases shows physical or performance characteristics significantly inferior to those of either grease before mixing. An incompatibility issue could be reflected in reduced lubricating performance due to the modified composition of the fluids and additives from intermixing. Usually, problems are not obvious until the lubricated apparatus is in use. However, if two incompatible greases are mixed, lubrication failure is inevitable. Changes in physical properties would be reflected by a softening or hardening of grease consistency, or decreased shear stability upon mechanical working and even reduction in thermal stability identified by a reduction in dropping point. Soft or runny grease is an indication of the problem. A grease that is much thicker than its original consistency may indicate incompatible mixing [14].

Grease color should also be observed. For example, if the original lubricant was green but has turned brown by the time of inspection, incompatible greases may have been mixed. Incompatible greases are a factor in many failures. Polyurea- and lithium-based greases, for example, break down rapidly when mixed.

It is best to know in advance which types of greases can be used together and which should not. Some greases cannot be mixed with others even when both types meet specifications. Unless this incompatibility is understood and accounted for, a switch to different grease can have serious consequences. The causes of incompatibilities of lubricants are given in Section 4.2.

4.7 LUBRICATION FAILURES OF ELECTRICAL EQUIPMENT: CASE STUDIES

4.7.1 CB FAILURES CAUSED BY LUBRICATION AT U.S. COMMERCIAL NUCLEAR POWER PLANTS

The data shown in this section are derived from a report [110] prepared for the Division of Risk Analysis and Applications of Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission (NRC). This report documents a study performed on the set of common-cause failures (CCF) of CBs from 1980 to 2000. The data studied here were derived from the NRC CCF database, which is based on U.S. commercial nuclear power plant event data (Tables 4.10 through 4.12).

Only the failures caused by improper lubrication are presented in the tables. It was found that improper lubrication determined on about 50 units caused 30% (24 out of 80) of all LV and MV CB failure events at nuclear power plants in 1980–2000. The events were classified as either fail-to-open or fail-to-close. The failure mode

TABLE 4.10**Failure Events with Reactor Trip Breakers (RTBs) Caused by Inadequate Lubrication**

Year	# of Units	Description of Event	Piece Part	Cause
1982	4	Breakers failed to trip on undervoltage	UV trip assembly	Inadequate lubrication, excessive periodic maintenance (PM) interval
1983	3	Same	Same	Same
1984	N/A	Undervoltage trip response time was found out of specifications	Mechanical assembly	Lack of proper amount of lubricant on the bearings of the breakers' frame assemblies
1984	2	Undervoltage trip response time was found out of specifications high	Mechanical assembly	Same
1985	2	Undervoltage trip response time was found to be out of the allowable tolerance	Mechanical assembly	Lack of lubrication and dirt accumulation on from frame assembly
1992	1	Breaker failed to close	Latch assembly	Inadequate lubrication of the breaker operating mechanism latch
1994	2	Breakers would not close from the hand switch in the main control room, the latch stuck in mid travel	Latch assembly	Insufficient lubrication of the inertia latch

Source: Modified from *Common-Cause Failure Event Insights Circuit Breakers*, NUREG/CR-6819, Vol. 4, INEEL/EXT-99-00613, May 2003, Online. Available: www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr6819/.

for the majority of CB events is fail-to-close (55%). The fail-to-open failure mode accounted for the remaining 45% of the events.

As follows from the data presented in this report, either a lack of lubrication of different mechanical parts or a hardened lubricant was the major cause of the failure. It was concluded that improper lubrication was a result of an ineffective maintenance program, which was either incomplete or not performed according to OEM's recommended schedule.

Review of the data given in the NRS report confirms the importance of properly provided lubrication, which in most cases is given in detail in the OEM Instruction Manual for each particular power device. It usually includes a list of the points/parts to lubricate, the lubrication products to use and the recommended time interval between maintenance lubrications. Very often the instruction manual will suggest shortening the lubrication interval if the unit might be exposed to a corrosive environment.

4.7.2 OVERHEATING OF THE MV SWITCH

Electrical equipment overheating is often caused by an increased CR. The cause of high resistance may be related to improper maintenance, including insufficient

TABLE 4.11
Failure Events with MV CBs

Year	# of Units	Description of Event	Piece Part	Cause
1986	4	4160 Vacuum CBs would not close	Spring charging motor	Lack of lubrication, dirty breakers, loose connections
1987	2	4160 Vacuum CBs would not charge	Same	Lack of lubrication, dirty contacts and dirty closing mechanism
1991	N/A	One 4160 Vacuum CB failed to open and several more degraded	Latch assembly	Hardened grease and lack of lubrication, maintenance incomplete
1995	1	4 kV supply CB closed during testing but failed to instantly recharge	Mechanical assembly	Aging of the latch monitor pivot bearing lubrication
1996	1	A failure of a roll pin securing a spring for a latch pawl on a 4 kV CB	Latch assembly	Lubricant was inadvertently removed from breaker parts
1997	5	Five safety related CBs failed to open on demand during separate evolution	Mechanical assembly	The main and auxiliary contacts were not lubricated as recommended by OEM operating mechanism latch

Source: Modified from *Common-Cause Failure Event Insights Circuit Breakers*, NUREG/CR-6819, Vol. 4, INEEL/EXT-99-00613, May 2003, Online. Available: www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr6819/.

lubrication. An example of ineffective maintenance is based on the case of overheating failure of the MV switch. After the failure the switch was disassembled and thoroughly inspected. The contact parts (blades and jaws) have been inspected to determine the cause of overheating [111].

During the examination it was found that the contact parts on different phases look different: the surfaces of two blades are discolored across the whole area of the blades, which is a signature of continuous overheating (Figure 4.1). The surface of the blades on the third phase still had a metallic luster of the original tin plating and did not show signs of overheating.

The material of the blades is tin-plated copper. It is well known that tin, when it is heated in the presence of air, oxidizes with the formation of highly resistant tin oxide (SnO₂), which has off-white color. It is possible that the color of presumably overheated blades (frosty and dull) is the color of oxidized tin plating.

An examination of the jaws showed that the surfaces also look different: two phases have dark oxidized surfaces and the third phase has a metallic luster (Figure 4.2). The areas where the blades come in contact with the jaws on two phases with signs of overheating also have signs of arcing, but no arcing fingerprints are found on the third phase.

An additional difference between phases was the brown deposit found on the blade and the jaw surfaces of one phase, which did not show signs of overheating.

TABLE 4.12
Failure Events with 480 VAC CBs

Year	# of Units	Description of Event	Piece Part	Cause
1984	5	One CB failed to trip when the undervoltage device was deenergized and two CBs failed to trip within specified time limit.	Mechanical assembly	Dirt and lack of lubrication
1985	4	Feeder breakers failed to close on demand	Mechanical assembly	Dirty and dry lubricant on the trip latch adjustment parts
1986	2	Feeder breakers were binding	Mechanical assembly	Dirty hardened grease
1987	2	Breakers found not operational, CBs would not trip	Mechanical assembly	Lack of lubrication of the internal moving parts
1988	1	The normal feeder breaker from a transformer would not close when transferring from alternate to normal power	Relay	Lack of lubrication
1989	1	The alternate breaker failed to close when the normal breakers were tripped	Mechanical assembly	Lack of proper lubrication of the trip rod bearings
1991	2	Breakers failed to close due to mechanical binding	Mechanical assembly	Dried out, hardened lubricant
1992	2	The normal supply breaker failed to close on demand. The alternate feed breaker failed to close during a hot transfer.	Mechanical assembly	Lack or hardening of lubrication
1997	3	Breakers failed to close on demand	Mechanical assembly	Hardened grease on the stop and main drive link rollers, the rollers were not cleaned and lubricated during PM
1997	N/A	Several breakers failed to trip	Mechanical assembly	Lack of lubrication, lubricant was removed during refurbishment and not reinstalled
1997	N/A	Several breakers on all three phases did not trip in the required time	Mechanical assembly	Aging and degraded lubricants resulting from ineffective maintenance program

Source: Modified from *Common-Cause Failure Event Insights Circuit Breakers*, NUREG/CR-6819, Vol. 4, INEEL/EXT-99-00613, May 2003, Online. Available: www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr6819/.

No deposit was found on or around the contact area of the blades and the contact area on jaws on the other two phases where arcing occurred.

Finding out why the parts look so different may help to identify the cause of overheating. The brown deposit is most likely composed of the residues of the dried-out grease applied to the surfaces of the blades around the contact area. The appearance



FIGURE 4.1 The blades of the switch. (This picture and associated copyrights are proprietary to, and used with the permission of Schneider Electric.)



FIGURE 4.2 The jaws of the switch. (This picture and associated copyrights are proprietary to, and used with the permission of Schneider Electric.)

and locations of the deposit allow inferring that the grease was heated above the lubricant maximum working temperature, causing the grease to melt and leak down towards pivoted points at the bottom of the blade.

To determine the cause of the overheating, the plant maintenance records have been reviewed. It was found that the switch was installed 13 years before the overheating happened. OEM Instruction Manual for this type of switch defines the maintenance terms, procedure and lubrication products. However, the annual maintenance log showed that the maintenance tasks did not include any adjustment or

relubrication of the disconnect assembly. Therefore, during the 13-year period of the switch being in service, the switch contacts have not been properly lubricated and a new lubricant has never been added to the switch. It is well known that no lubricant can survive 13 years in service. After 13 years in service most of the lubricant presumably applied on the contacts during the assembly of the switch will have disappeared, with some dry grease still visible on one of the phases.

With the lack of lubrication, three different deterioration processes could have caused the rise in electrical resistance on the switch contacts. First, on the blades on two phases with the least amount of lubricant, tin plating was exposed to atmospheric oxygen and thus not protected from *oxidation*. Due to heavy oxidation, a thick layer of highly resistant gray tin oxide covered the contact areas, which resulted in high resistance on the switch electrical contacts.

Secondly, the role of the lubricants is very important in protection of the contact from fretting, another damaging type of corrosion to which tin plating is specifically subjected [112]. Therefore, a lack of lubricants on tin-plated surfaces could lead to surface damage by *fretting corrosion*, resulting in additional resistance growth (see Section 2.5).

There is another possible cause of the growing resistance. While oxidation and fretting corrosion led to growing CR, they in turn caused more heat generation on the energized contacts and a temperature increase on the contacts during the service. An extended exposure of the contacts made of tin-plated copper to elevated temperatures usually induces the formation of intermetallic compounds (IMCs) on the interface between the plating (tin) and the base metal (copper) [113]. IMCs have a very high electrical resistance (see Section 2.5). This factor added to further growth of contacts resistance, which in turn further increased the amount of heat generated.

In the scenario of the switch overheating suggested in Ref. [111], a major cause of the overheating was an improper maintenance procedure and lack of lubrication, which resulted in severe atmospheric and fretting corrosion of the contacts, and the formation of a copper–tin IMC. All these deteriorating factors together led to the growth of contact electrical resistance. Abnormally resistant contact areas produced a continuous flow of extreme heat. Continuous overheating led to decreased jaw spring strength and thus to a decreased contact pressure, which all together resulted in arcing.

4.8 INFORMATIONAL SOURCES FOR LUBRICANTS

There are many valuable information resources on the subject of lubrication [23].

- a. *Operations and maintenance manuals.* The primary information sources are the manufacturer's installation, operation, and maintenance manuals. The information contained in these manuals applies specifically to the equipment requiring servicing. The operation and maintenance manual will usually outline the required characteristics of the lubricants as well as a recommended schedule for replacement or filtering. If the maintenance manual is not available, or is vague in its recommendations, lubricant manufacturers and distributors are other sources of information.

- b. *Lubricant manufacturers* are probably the most valuable source of information and should be consulted for specific application situations, surveys, or questions [114]. The details of the companies are easily available via the Internet and phone services (Table 4.13).
When choosing a lubricant for a particular piece of equipment, all the pertinent information on the equipment, such as operating speed, frequency of operation, operating temperature, and any other special or unusual conditions, should be provided to the lubricant manufacturer or distributor so that a lubricant with the proper characteristics can be chosen. Some discretion should be used when dealing with a lubricant salesperson in order to prevent purchasing an expensive lubricant with capabilities in excess of what is required.
- c. *Industry standards* organizations such as ANSI, ASTM, AGMA, and IEEE publish standard specifications for lubricants and lubricating standards for various types of equipment.
- d. *Engineering and trade publications and journals* such as Lubrication, Lubrication Engineering, and Wear specialize in the area of lubrication and tribology. Articles featured in these publications are generally technical in nature and describe the results of current research. Occasionally research results are translated into practical information that can be readily applied. General trade publications and magazines such as *Power*, *Power Engineering*, *Hydraulics and Pneumatics*, *Machine Design*, *Pump and*

TABLE 4.13
Web Sites, E-mail Addresses, and Technical Service Phone Numbers of Major Lubricant Manufacturers in the United States

Company	Web Site (www. prefix)	Technical Service Numbers
Dow Corning (live help available)	dowcorning.com/content/support/	989-496-7881
Klueber Lubrication NA	klueber.com	800-447-2238
British petroleum	bplubricants.com	877-582-3727
Castrol industrial	castrollhdl.com	800-462-0835, ext. 3
Chevron	chevron-lubricants.com chevron.com/products/customerservices/	
Texaco	texaco.com	800-582-3835
ConocoPhillips	conocophillips.com	800-255-9556 (Conoco) 800-766-0050 (Phillips) 800-368-1267 (Kendall)
ExxonMobil	exxonmobil.com/lubes/	800-443-9966, ext. 3
Lubriplate	lubriplate.com	800-347-5343
Pennzoil-Quakerstate	pennzoil-quakerstate.com	800-458-4998
Shell	shell-lubricants.com	800-231-6950
Nye synthetic lubricants	http://www.nyelubricants.com/techhelp@nyelubricants.com	508-996-6721
Anderol	info@anderol.com (e-mail)	888-263-3765

Systems, and *Plant Engineering* magazine frequently contain practical articles pertaining to lubrication of bearings, gears, and other plant equipment.

- e. *Lubrication charts.* *Plant Engineering* magazine publishes “Exclusive Guide to Synthetic Lubricants” and “Exclusive Interchangeable Industrial Lubricants” [15,115]. Each of these charts is updated every 3 years. These charts cross-reference lubricants by application and the company producing the product. *Plant Engineering* magazine product names are provided by the manufacturers, and the publishing of the data does not reflect the quality of the lubricant, imply the performance expected under particular operating conditions, or serve as an endorsement.

As an example of the information contained in the interchangeable lubricant chart, the 2004 chart identifies available products from 118 lubricant companies in nine categories. Fluid products in each category are listed within viscosity ranges. Greases comprise NLGI 2 only. Included is a chart titled “Viscosity/Grade Comparison Chart” that tabulates viscosity equivalents for ISO viscosity grade, kinematic viscosity (CSt), Saybolt viscosity (SUS), gear lubricant (AGMA) specifications, EP gear lubricant, and worm gear lubricant (Comp). *Plant Engineering* magazine notes that the synthetic lubricant products presented in each category are not necessarily interchangeable or compatible. Interchangeability and compatibility depend on a variety of interrelated factors, and each application requires an individual analysis.

- f. *The Internet* offers access to a large amount of information, including lubrication theory, product data, and application information. The Internet also provides a means of communicating and sharing information with personnel at other facilities. Problems, causes, and solutions are frequently described in great detail, although caution should be used when evaluating information obtained through the Internet. The amount of information located depends on the user’s skills at applying the most pertinent keywords on any of the search engines. Hyperlinks are usually available and lead to other information sources. Users should note that broad search categories, such as “lubrication,” will provide the greatest returns but will undoubtedly include much extraneous data. Generally, inserting too many words in the search field narrows the scope of the search and may produce little or no useful information. The search field must be adjusted until the desired information is obtained or the search is abandoned for another reference source.
- g. *Libraries.* In a manner similar to the Internet searches, librarians can also help locate information within their collections or outside their collections by conducting book and literature searches. Unlike the Internet, literature searches rely on large databases that require password entry not available to the general public. Therefore, these searches are usually conducted by a reference librarian. The search process is a very simple method used for locating books on a specific subject, or specific articles that have been included in technical publications. Again, the amount of information located depends on using the proper search keywords. Searches can be expanded or contracted until the desired information is obtained.

4.9 LUBRICATION GLOSSARY

A

Additive: A compound that enhances some property of, or imparts some new property to, the base fluid. In some hydraulic fluid formulations, the additive volume may constitute as much as 20% of the final composition. The more important types of additives include antioxidants, antiwear additives, corrosion inhibitors, viscosity index improvers, and foam suppressants.

Additive stability: The ability of additives in the fluid to resist changes in their performance during storage or use.

Adhesion: The property of a lubricant that causes it to cling or adhere to a solid surface.

ANSI: American National Standards Institute.

Antifoam agent: One of two types of additives used to reduce foaming in petroleum products: silicone oil to break up large surface bubbles, and various kinds of polymers that decrease the number of small bubbles entrained in the oils.

Antioxidants: Prolong the induction period of base oil in the presence of oxidizing conditions and catalyst metals at elevated temperatures. The additive is consumed and degradation products increase not only with increasing and sustained temperature, but also with increases in mechanical agitation or turbulence and contamination (water, metallic particles, and dust).

Antiwear additives: Improve the service life of tribological elements operating in the boundary lubrication regime. Antiwear compounds (e.g., ZDDP and TCP) start decomposing at 90–100°C and even at a lower temperature if water (25–50 ppm) is present.

ASTM: American Society for Testing Materials.

B

Base stock: The base fluid, usually a refined petroleum fraction or a selected synthetic material, into which additives are blended to produce finished lubricants.

Boundary lubrication: Form of lubrication between two rubbing surfaces without development of a full-fluid lubricating film. Boundary lubrication can be made more effective by including additives in the lubricating oil that provide a stronger oil film, thus preventing excessive friction and possible scoring. Antiwear additives are commonly used in more severe boundary lubrication applications. The more severe cases of boundary lubrication are defined as extreme pressure conditions; they are met with lubricants containing EP additives that prevent sliding surfaces from fusing together at high local temperatures and pressures.

C

Centipoise (cp): A unit of absolute viscosity. 1 centipoise = 0.01 poise.

Centistoke (cst): A unit of kinematic viscosity. 1 centistoke = 0.01 stoke.

Centralized lubrication surfaces: A system of lubrication in which a metered amount of lubricant or lubricants for the bearing of a machine or group of machines is supplied from a central location.

Chemical stability: The tendency of a substance or mixture to resist chemical change.

Cloud point: The temperature at which waxy crystals in an oil or fuel form a cloudy appearance.

Compound: (1) Chemically speaking, a distinct substance formed by the combination of two or more elements in definite proportions by weight and possessing physical and chemical properties different from those of the combining elements. (2) In petroleum processing, generally connotes fatty oils and similar materials foreign to petroleum added to lubricants to impart special properties.

Compounded oil: Petroleum oil to which has been added other chemical substances.

Consistency: The degree to which a semisolid material such as grease resists deformation. (See ASTM Designation D 217.) Sometimes used qualitatively to denote viscosity of liquids.

Contaminant: Any foreign or unwanted substance that can have a negative effect on system operation, life or reliability.

Corrosion: The decay and loss of a metal due to a chemical reaction and its environment. It is a transformation process in which the metal passes from its elemental form to a combined (or compound) form.

Corrosion inhibitor: Additive for protecting lubricated metal surfaces against chemical attack by water or other contaminants. There are several types of corrosion inhibitors. Polar compounds wet the metal surface preferentially, protecting it with a film of oil. Other compounds may absorb water by incorporating it in a water-in-oil emulsion so that only the oil touches the metal surface. Another type of corrosion inhibitor combines chemically with the metal to present a nonreactive surface.

D–E

Degradation: The progressive failure of a machine or lubricant.

Detergent: In lubrication, a detergent is either an additive or a compounded lubricant having the property of keeping insoluble matter in suspension, thus preventing its deposition where it would be harmful. A detergent may also redisperse deposits already formed.

Dielectric strength: A measure of the ability of an insulating material to withstand electric stress (voltage) without failure. Fluids with high dielectric strength (usually expressed in volts or kilovolts) are good electrical insulators. (ASTM Designation D 877.)

Emulsibility: The ability of a nonwater-soluble fluid to form an emulsion with water.

Emulsifier: An additive that promotes the formation of a stable mixture, or emulsion, of oil and water. Common emulsifiers are: metallic soaps, certain animal and vegetable oils, and various polar compounds.

Emulsion: Intimate mixture of oil and water, generally of a milky or cloudy appearance. Emulsions may be of two types: oil-in-water (where water is the continuous phase) and water-in-oil (where water is the discontinuous phase).

Environmental: All material and energy present in and around an operating contaminant system, such as dust, air moisture, chemicals, and thermal energy.

EP additive: Lubricant extreme pressure additive that prevents sliding metal surfaces from seizing under conditions of extreme pressure. At the high local temperatures associated with metal-to-metal contact, an EP additive combines chemically with the metal to form a surface film that prevents the welding of opposing asperities, and the consequent scoring that is destructive to sliding surfaces under high loads. Reactive compounds of sulfur, chlorine, or phosphorus are used to form these inorganic films.

EP lubricants: Extreme Pressure (EP) lubricants that impart to rubbing surfaces the ability to carry appreciably greater loads than would be possible with ordinary lubricants without excessive wear or damage.

F–G

Film strength: Property of a lubricant that acts to prevent scuffing or scoring of metal parts.

Fire point: Temperature to which a combustible liquid must be heated so that the released vapor will burn continuously when ignited under specified conditions.

Fire-resistant fluid: Lubricant used especially in high-temperature or hazardous hydraulic applications. Three common types of fire-resistant fluids are: (1) water–petroleum oil emulsions, in which the water prevents burning of the petroleum constituent; (2) water–glycol fluids; and (3) nonaqueous fluids of low volatility, such as phosphate esters, silicones, and halogenated hydrocarbon-type fluids.

Flash point: Temperature to which a combustible liquid must be heated to give off sufficient vapor to form a flammable mixture with air when a small flame is applied under specified conditions. (ASTM Designation D 92.)

Force feed: A system of lubrication in which the lubricant is supplied to lubrication the bearing surface under pressure.

Friction: Resisting force encountered at the common boundary between two bodies when, under the action of an external force, one body moves or tends to move relative to the surface of the other.

Graphite: A crystalline form of carbon having a laminar structure, which is used as a lubricant. It may be of natural or synthetic origin.

Grease: A lubricant composed of oil or oils thickened with a soap or other thickeners to a semisolid or solid consistency.

H

Hydraulic fluid or oil: Fluid serving as the power transmission medium in a hydraulic system. The most commonly used fluids are petroleum oils, synthetic lubricants, oil–water emulsions, and water–glycol mixtures. The principal requirements of a premium hydraulic fluid are proper viscosity, high viscosity index, antiwear protection (if needed), good oxidation stability, adequate pour point,

good demulsibility, rust inhibition, resistance to foaming, and compatibility with seal materials. Antiwear oils are frequently used in compact, high-pressure, and capacity pumps that require extra lubrication protection.

Hydrocarbons: Compounds containing only carbon and hydrogen. Petroleum consists chiefly of hydrocarbons.

Immiscible: Incapable of being mixed without separation of phases. Water and petroleum oil are immiscible under most conditions, although they can be made miscible with the addition of an emulsifier.

Inhibitor: Any substance that slows down or prevents such chemical reactions as corrosion or oxidation.

Insolubles: Particles of carbon or agglomerates of carbon and other materials. Indicates deposition or dispersant drop-out in an engine. Not serious in a compressor or gearbox unless there has been a rapid increase in these particles.

ISO: International Standards Organization, sets viscosity reference scales.

ISO viscosity: A number indicating the nominal viscosity of an industrial fluid grade lubricant at 40°C/104°F as defined by ASTM Standard Viscosity System for Industrial Fluid Lubricants D 2422 (identical to ISO Standard 3448).

L–M–N

Liquid: Any substance that flows readily or changes in response to the smallest influence. More generally, any substance in which the force required to produce a deformation depends on the rate of deformation rather than on the magnitude of the deformation.

Load-carrying: Property of a lubricant to form a film on the lubricated surface, which resists rupture under given load capacity conditions. Expressed as the maximum load the lubricated system can support without failure or excessive wear.

Lubricant: Any substance interposed between two surfaces in relative motion for the purpose of reducing the friction and/or the wear between them.

Lubricity: Ability of an oil or grease to lubricate; also called film strength.

Mineral oil: Oil derived from a mineral source, such as petroleum, as opposed to oils derived from plants and animals.

Miscible: Capable of being mixed in any concentration without separation of phases; for example, water and ethyl alcohol are miscible.

Moly: Molybdenum disulfide (MoS_2), a solid lubricant and friction reducer, colloiddally dispersed in some oils and greases.

Multigrade oil: An oil meeting the requirements of more than one SAE viscosity grade classification, and may therefore be suitable for use over a wider temperature range than a single-grade oil.

Naphthenic: A type of petroleum fluid derived from naphthenic crude oil, containing a high proportion of closed-ring methylene groups.

O

Oil: A greasy, unctuous liquid of vegetable, animal, mineral, or synthetic origin.

Oil ring: A loose ring, the inner surface of which rides a shaft or journal and dips into a reservoir of lubricant from which it carries the lubricant to the top of a bearing by its rotation with the shaft.

Oiliness: That property of a lubricant that produces low friction under conditions of boundary lubrication. The lower the friction, the greater the oiliness.

Oxidation: Occurs when oxygen attacks petroleum fluids. The process is accelerated by heat, light, metal catalysts, and the presence of water, acids, or solid contaminants. It leads to increased viscosity and deposit formation.

Oxidation inhibitor: Substance added in small quantities to a petroleum product to increase its oxidation resistance, thereby lengthening its service or storage life; also called antioxidant. An oxidation inhibitor may work in one of these ways: (1) by combining with and modifying peroxides (initial oxidation products) to render them harmless, (2) by decomposing the peroxides, or (3) by rendering an oxidation catalyst inert.

Oxidation stability: Ability of a lubricant to resist natural degradation upon contact with oxygen.

P–R

Paraffinic: A type of petroleum fluid derived from paraffinic crude oil and containing a high proportion of straight chain saturated hydrocarbons. Often susceptible to cold flow problems.

Poise: A measure of absolute viscosity numerically equal to the force required to move a plane surface of 1 cm²/s when the surfaces are separated by a layer of fluid 1 cm in thickness. It is the ratio of the shearing stress to the shear rate of a fluid and is expressed in dyne seconds per square centimeter (dyne sec/cm²); 1 centipoise is equal to 0.01 poise.

Polymerization: The chemical combination of similar-type molecules to form larger molecules.

Pour point: The lowest temperature at which an oil or distillate fuel is observed to flow, when cooled under conditions prescribed by the test method ASTM D 97. The pour point is 3°C (5°F) above the temperature at which the oil in a test vessel shows no movement when the container is held horizontally for 5 s.

Pumpability: The low temperature, low shear stress–shear rate viscosity characteristics of an oil that permit satisfactory flow to and from the engine oil pump and subsequent lubrication of moving components.

Refining: A process of reclaiming used lubricant oils and restoring them to a condition similar to that of virgin stocks by filtration, clay adsorption, or more elaborate methods.

Ring lubrication: A system of lubrication in which the lubricant is supplied to the bearing by an oil ring.

Rings: Circular metallic elements that ride in the grooves of a piston and provide compression sealing during combustion. Also used to spread oil for lubrication.

S

SAE: Society of Automotive Engineers, serving the automotive industry.

Saybolt universal viscosity: The time in seconds (SUV or SUS) required for 60 cm³ of a fluid to flow through the orifice of the Standard Saybolt Universal Viscometer at a given temperature under specified conditions. (ASTM Designation D 88.)

Semisolid: Any substance having the attributes of both a solid and a liquid. Similar to semiliquid but more closely related to a solid than a liquid. More generally, any substance in which the force required to produce a deformation depends both on the magnitude and on the rate of the deformation.

Sludge: Insoluble material formed as a result either of deterioration reactions in oil or of contamination of oil, or both.

Solid: Any substance having a definite shape which it does not readily relinquish. More generally, any substance in which the force required to produce a deformation depends upon the magnitude of the deformation rather than upon the rate of deformation.

Specific gravity: The ratio of the weight of a given volume of material/liquid to the weight of an equal volume of water.

SSU: Saybolt universal seconds (SUS), a unit of measure used to indicate viscosity at 100°F.

Stoke (St): Kinematic measurement of a fluid's resistance to flow defined by the ratio of the fluid's dynamic viscosity to its density.

Surfactant: May increase the oil's affinity for metals and other materials.

Synthetic hydrocarbon: Oil molecule with superior oxidation quality tailored primarily out of paraffinic materials.

Synthetic lubricant: A lubricant produced by chemical synthesis rather than by extraction or refinement of petroleum to produce a compound with planned and predictable properties.

T

Thermal conductivity: Measure of the ability of a solid or liquid to transfer heat.

Thermal stability: Ability of a fuel or lubricant to resist oxidation under high temperature operating conditions.

Thin film lubrication: A condition of lubrication in which the film thickness of the lubricant is such that the friction between the surfaces is determined by the properties of the surfaces as well as by the viscosity of the lubricant.

Tribology: The science and technology of interacting surfaces in relative motion, including the study of lubrication, friction, and wear. Tribological wear is wear that occurs as a result of relative motion at the surface.

V

Vapor pressure: Pressure of a confined vapor in equilibrium with its liquid at specified temperature thus, a measure of a liquid's volatility.

Varnish: When applied to lubrication, a thin, insoluble, nonwipeable film deposit occurring on interior parts, resulting from the oxidation and polymerization of fuels and lubricants. Can cause sticking and malfunction of close-clearance moving parts. Similar to, but softer, than lacquer.

Viscometer or viscosimeter: An apparatus for determining the viscosity of a fluid.

Viscosity: Measurement of a fluid's resistance to flow. The common metric unit of absolute viscosity is the poise, which is defined as the force in dynes required to move a surface 1 cm² in area past a parallel surface at a speed of 1 cm/s, with the surfaces separated by a fluid film 1 cm thick. In addition to kinematic viscosity, there are other methods for determining viscosity, including the Saybolt universal viscosity (SUV), Saybolt Furol viscosity, Engier viscosity, and Redwood viscosity. Since viscosity varies inversely with temperature, its value is meaningless until the temperature at which it is determined is reported.

Viscosity grade: Any of a number of systems which characterize lubricants according to viscosity for particular applications, such as industrial oils, gear oils, automotive engine oils, automotive gear oils, and aircraft piston engine oils.

Viscosity index (VI): A commonly used measure of a fluid's change of viscosity with temperature. The higher the viscosity index, the smaller the relative change in viscosity with temperature.

Viscosity index improvers: Additives that increase the viscosity of the fluid throughout its useful temperature range. Such additives are polymers that possess thickening power as a result of their high molecular weight and are necessary for the formulation of multigrade engine oils.

Viscosity modifier: Lubricant additive, usually a high-molecular-weight polymer that reduces the tendency of an A148 viscosity to change with temperature.

Viscosity, absolute: The ratio of the shearing stress to the shear rate of a fluid. It is usually expressed in centipoise.

Viscosity, kinematic: The time required for a fixed amount of oil to flow through a capillary tube under the force of gravity. The unit of kinematic viscosity is the stoke or centistoke (1/100 of a stoke). Kinematic viscosity may be defined as the quotient of the absolute viscosity in centipoises divided by the specific gravity of a fluid, both at the same temperature.

Viscosity, SUS: Saybolt universal seconds (SUS), which is the time in seconds for 60 mL of oil to flow through a standard orifice at a given temperature. (ASTM Designation D88-56.)

Viscous: Possessing viscosity. Frequently used to imply high viscosity.

Volatility: This property describes the degree and rate at which a liquid will vaporize under given conditions of temperature and pressure.

W-Z

Wear: The attrition or rubbing away of the surface of a material as a result of mechanical action.

ZDDP: Zinc dialkyldithiophosphate, an antiwear additive found in many types of hydraulic and lubricating fluids.

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5 Insulation, Coatings, and Adhesives in Transmission and Distribution Electrical Equipment

5.1 INSULATING MATERIALS IN POWER EQUIPMENT

A dielectric material that resists the flow of electric charge is called an insulator. In an electrical machine, the electrical insulation ensures that current flows only along the conductors and not between individual conductors or between the conductor and the ground. Insulating materials are used in electrical equipment not only for separation of current-carrying parts from each other and from the environment, but also for support of electrical conductors. Insulating materials can serve as practical and safe insulators for low to high voltages (up to thousands of volts).

In electrical systems insulators are commonly used as a flexible coating on electric wire and cable to avoid wires from touching each other and be touched, and therefore preventing electrocution and fire hazards. In coaxial cables the center conductor must be supported exactly in the middle of the hollow shield in order to prevent electromagnetic wave reflections. An insulated wire or cable has a voltage rating and a maximum conductor temperature rating. It may not have an ampacity (current-carrying capacity) rating, since this depends on the surrounding environment (e.g., ambient temperature).

5.1.1 INSULATING MATERIALS USED IN THE ELECTRICAL INDUSTRY

Dielectric materials do not conduct electricity; they have a very low electrical conductivity. Three classes of solid dielectric materials are used for insulation: inorganic, organic, and composites [1]. Inorganic materials are *ceramics*, such as porcelain, alumina, and so on, *glass*, and *cements* or *minerals* (mica). *Polymer* insulators, or non-ceramic insulators (NCI), were first developed in the 1960s and installed in the 1970s, and developed into mature products in the 1980s. Polymers made of organic materials or *composites* such as Kevlar, carbon, and fiberglass are used for insulation. Lower overall cost, easy installation and light weight are among the major reasons for using polymer insulators, although there are some concerns, such as reduced life expectancy and lack of knowledge about polymers' aging. There are also many nonsolid dielectric materials that are used in the electrical industry, for example, oil,

gas, and vacuum. These insulating media will be discussed in Section 5.6 in more detail.

Solid organic insulating materials may be divided into two subclasses: thermoplastic and thermosetting (Table 5.1). A thermoplastic material is a polymer that softens or melts on heating, and becomes rigid again on cooling. Thermosetting insulation made of plastic that, when cured by heat or other means, such as radiation, catalysts, and so on, changes into a substantially infusible and insoluble product hardened by heating.

In electronic systems, printed circuit boards (PCB) are made from epoxy plastic and fiberglass. The nonconductive boards support layers of copper foil conductors. In electronic devices, the tiny and delicate active components are embedded within nonconductive epoxy or phenolic plastics, or within baked glass or ceramic coatings. In microelectronic components such as transistors and integrated circuits (ICs), the silicon material is normally a conductor because of doping, but it can easily be selectively transformed into a good insulator by the application of heat and oxygen. Oxidized silicon is quartz, that is, crystalline silicon dioxide.

In high voltage (HV) systems containing transformers and capacitors, using oil as a liquid insulator is the typical method of preventing arcs. The oil replaces the air in any spaces, which must support a significant voltage without electrical breakdown. Other methods of insulating HV systems are by using ceramic or glass wire holders, gas, or vacuum, and simply placing the wires with a large separation, using air as the insulation.

The safety and longevity of electrical power equipment strongly depend on the technical performance of multiple insulating materials used in the design of electro-mechanical machines. It is important to choose and apply insulating materials that

TABLE 5.1
Organic Insulating Materials

Type of Solid Insulation	Material	Chemical Variety, Abbreviated Name or Trademark
Thermoplastic	Rubber	Natural, butyl, and silicone
	Polyamide	PA, Nylon
	Polyester	PE, Mylar
	Polypropylene	PP
	Polystyrene	PS
	Polyvinyl chloride	PVC
	Polymethylmetacrylate	PMMA
	Polycarbonate	PC
	PTFE	PTFE, Teflon
Thermosetting	PE	PE, LDPE, MDPE, HDPE, XLPE
	Ethylene-Propylene	EPR
	Polyimide	PI
	Polyetheretherketone	PEEK
	Epoxy	Phenolic, silicone, and polyester resins

perform well and do not fail in various environments. Insulating materials should withstand environmental parameters such as humidity, dust, temperature, and contamination for practical applications of electrical apparatus indoor and outdoor.

Insulating materials should endure working and environmental conditions such as mechanical stresses, electrical fields, moisture, ozone, UV light, surface arcing, and contamination. In the following sections, the aging issues of some insulating materials used in power distribution and transmission will be discussed.

In electric power transmission, suspended wires are bare except where they enter buildings, and they are insulated by the surrounding air. Insulators are required at points where they are supported by utility poles or pylons. Insulators are also required where the wire enters buildings or electrical devices, such as transformers or CBs, to insulate the wire from the case. These hollow insulators with a conductor inside them are called bushings.

Insulators used for HV power transmission are made from glass, porcelain, or composite polymer materials (Figure 5.1). Porcelain insulators are made from clay, quartz, or alumina and feldspar, and are covered with a smooth glaze to shed water. Insulators made from porcelain rich in alumina are used where high mechanical strength is a criterion. Porcelain has a dielectric strength of about 4–10 kV/mm [2]. The advantages of porcelain insulators include superior electrical properties, good mechanical properties (especially tensile strength), good creep resistance at room



FIGURE 5.1 Insulators made of dielectric composite material (silicone). (Piedmont Bushings & Insulators, Online. Available: http://www.pbi.com/insulator_pbi.html. With permission.)

temperature, high corrosion resistance, minimal leakage problems, and less adverse effects from changing temperatures.

Glass has a higher dielectric strength, but it attracts condensation and the thick irregular shapes needed for insulators are difficult to cast without internal strains [3]. Some insulator manufacturers stopped making glass insulators in the late 1960s, switching to ceramic materials.

Recently, some electric utilities have begun switching to *polymer composite* materials for some types of insulators. These are typically composed of a central rod made of *fiber-reinforced plastic* and an outer weather shed made of *silicone rubber* or *EPDM (ethylene propylene diene monomer) rubber*. EPDM is a type of synthetic rubber, an elastomer used in a wide range of applications. Composite materials have been utilized for several years to replace porcelain as insulation media.

There are proven advantages of the composites such as lower weight, pollution resistance, and weather and explosion proof. An additional advantage is that composite insulation allows for a more compact and reliable design of lines and substations for higher ratings. Composite material may have different properties depending on the mixture of substances, manufacturing process, surface and mechanical design, and so on. Composite insulators are less costly, are lighter in weight, and have excellent hydrophobic capability. This combination makes the composites ideal for service in polluted areas. However, these materials do not yet have the long-term proven service life of glass and porcelain.

To confirm better performance of composite insulators, a thorough testing including dielectric and long-term “field test” is required [4]. The composite insulation property of “hydrophobicity” (an ability to repel water) significantly improves the insulation’s pollution resistance behavior, but this should also be confirmed by accelerated pollution and stress aging tests for composite insulation in comparison with porcelain.

Insulators made of silicone rubber have been tested to find out whether the insulators could permanently work when electrically stressed beyond the recommended limits in polluted and clean tropical environments. The tested insulators included eight types of silicone rubber composite insulators, one type of hybrid silicone ceramic insulator and one semiconducting glazed porcelain insulator, while ordinary porcelain and glass insulators were used as the reference [5]. The tests showed that there is a possibility to increase the electric stress on silicone rubber insulators to levels higher than those used today on glass and porcelain insulators.

Insulation of electrical conductors (bus bars) in transformers and CBs is often composed of silicone rubber or epoxy resin, while the supporting insulator and bushing are made of glass, porcelain, ceramic, hybrid silicone ceramic, and semiconducting glazed porcelain (or their combinations).

For bus bar insulation, heat shrinkable tubing (Figure 5.2a), sleeves, tapes (Figure 5.2b), and sheets are used. This insulating material is made of specially formulated, cross-linked, flame-retardant, track-resistant polyolefin that will shrink to fit rectangular, square or round bus bars. It will also cover and insulate inline bolted connections of regular bus bars. Other heat-shrinkable materials are made of fluoropolymers and elastomers.

Often bus bars and CBs in switchgear may be insulated with glass-reinforced plastic insulation, treated to have low flame spread and to prevent tracking of current

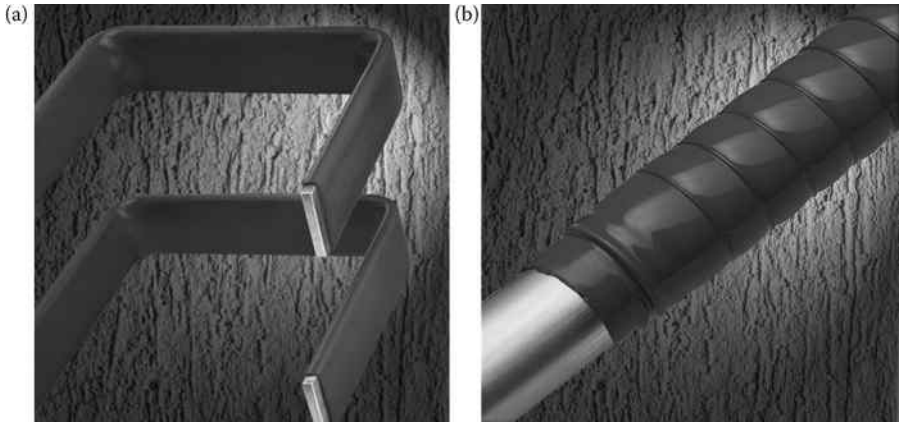


FIGURE 5.2 (See color insert.) A 5–35 kV bus with heat shrinkable tubing (a) and tape (b). Users should independently evaluate the suitability of the insulating material pictured above for their particular use. (From TE Connectivity, Online. Available: http://energy.te.com/index.asp?act=page&pag_id=2&pri_id=5&pls_id=29&prf_id=135&prp_parent=968. Photographs reprinted with permission.)

across the material. Thermosetting *epoxy* powders are specially formulated for electrical insulation applications. The epoxy is applied to a preheated metal surface by the fluidized-bed process. A dry epoxy powder melts, cures and produces a uniform film of insulating coating with excellent adhesion, corrosion and chemical resistance, and a good combination of mechanical, thermal and electrical properties.

Epoxy powder-coated bus bar insulation allows for closer component location in a system, which is ideal for single conductors or multiple conductor assemblies that may have numerous forms (Figure 5.3). Epoxy powder coating is also well suited for insulating thick conductors, in addition to conductors with multiple electrical contact points. The material has a high dielectric strength and is a durable insulator, impervious to most elements. Epoxy powder coating's high dielectric strength can be varied based on the application process and component preparation.

Insulation of bus bar shrouds and boots is usually made of polyvinyl chloride (PVC) material, which is formulated specially for electrical applications at HV. These insulators are flexible and reusable electrical insulating covers for bus and switchgear connections with special buttons making it easy to install, remove or replace them during maintenance.

5.1.2 THERMAL LIMITATION FOR ELECTRICAL INSULATION

Power electrical equipment when in service is a source of thermal energy. Its conductors may be heated up to very high temperatures, particularly in systems with high currents flowing through the conductors. On the other hand, every electrical insulation material has its own working temperature range beyond which it may melt or become flammable. Either event would cause a disastrous failure. Even at minor overheating of insulation above the working temperature maximum, the aging of insulation would accelerate and create defects and a decrease of insulating properties [6].

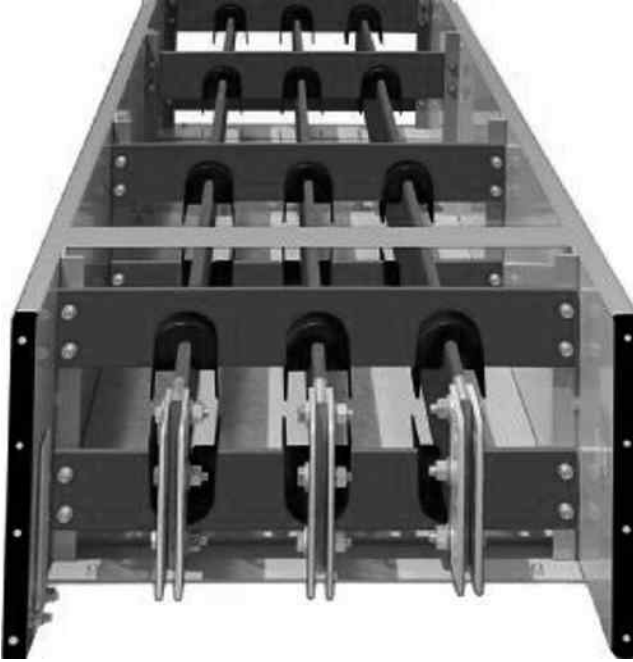


FIGURE 5.3 (See color insert.) Epoxy powder insulated MV bus. (From Park Electric Company Busway, Online. Available: <http://www.parkdetroit.com/What-We-Do/Busways>. With permission.)

IEEE Standard 1-1986, “IEEE Standard General Principles for Temperature Limits in the Rating of Electric Equipment and for the Evaluation of Electrical Insulation” [7], was developed to guide in the preparation of IEEE and other standards that deal with the selection of temperature limits and the measurement of temperature for specific types of electric equipment. Principles are included for the development of test procedures for thermal evaluation of electrical insulating materials (EIMs), insulation systems, and thermal classification for use in the rating of electric equipment.

IEEE Standard 1-2001, “IEEE Recommended Practice—General Principles for Temperature Limits in the Rating of Electrical Equipment and for the Evaluation of Electrical Insulation” [8], is intended to help in the preparation of standards that are principally concerned with the thermal endurance of EIM and simple combinations of such materials, with the establishment of limiting temperatures of electrical insulation system (EIS), and with the provision of general principles for thermal classification of EIS.

According to these standards and to ensure the safety and long life of electrical power equipment, a system of choosing a suitable insulating material in the electrical design has been developed. This system classified insulating materials based on the material thermal properties and the temperature working range and introduced the so-called *temperature classes of insulation*.

In the past, the temperature classes of electric insulators were simply divided into natural organics, inorganics, and their combinations. In the late 1930s, various types of synthetic resins have been developed and their application range gradually expanded to insulation. IEC issued a recommendation on the temperature classes of electric insulators, followed by IEC Publication 85 (1957), which established the classification system that is currently in use [9]. Later, when silicone resin became a popular insulator material, the new class (H) of insulators was added to the temperature classes (Table 5.2), and it became increasingly necessary to find applications for heat-resistant materials in electric instruments. The IEC standards [9,10] established several insulation classes (Y, A, E, B, F, and H).

According to these standards, insulation in each class cannot be exposed to temperatures higher than the *maximum allowed operation temperature*. In other standards, such as the National Electrical Manufacturers Association (NEMA) standard, classifications also rated insulation systems according to maximum allowable operating temperatures for motor insulation, where this classification is named “temperature tolerance classes” (A, B, F, and H). The testing techniques for the high-temperature life of new materials for temperature classification were investigated intensively in the United States [11].

TABLE 5.2
Thermal Class of Insulation Based on IEEE and IEC Standards

Thermal Class IEEE	Thermal Classification	
	IEEE	IEC
90	None	Y
105	A	A
120	E	E
130	B	B
155	F	F
180	H	H
200	N	200
220	R	220
240	S	240
>240	C	—

Sources: Modified from IEEE Standard 1–2001. *Recommended Practice—General Principles for Temperature Limits in the Rating of Electrical Equipment and for the Evaluation of Electrical Insulation*. IEEE Publishing, New York, NY. © 2001, IEEE; IEC Publication 85. *Recommendations for Classification of Materials for the Insulation of Electrical Machinery and Apparatus in Relation to their Thermal Stability in Service*, Publication of International Electrotechnical Commission (IEC), Geneva, Switzerland, 1957; IEC standards 60085. *Electrical Insulation—Thermal Evaluation and Destination*. Publication of International Electrotechnical Commission (IEC), Geneva, Switzerland, 2007.

Low-temperature Class-Y insulation (not classified in the United States) is typically made of cotton, silk, or paper; and its maximum temperature is 90°C , while high-end temperature (Class H) insulation is made of inorganic material glued with silicone resin or adhesives of equivalent performance with a maximum operating temperature of 180°C . Class C insulation is made of 100% inorganic material and its temperature limit is over 180°C .

International Standard IEC 60034-1 [12] classifies the temperature rise (TR) limits of insulation materials based on the maximum permissible temperatures that the various classes of insulation materials could withstand. The TR of the electrical machine is the increase in temperature that is permissible above this maximum ambient temperature. IEC standard [12] specifies a maximum ambient temperature of 40°C . A safe temperature is the sum of the maximum specified ambient temperature and the permitted TR due to the mechanical load. For example, for Class E insulation with a maximum permissible temperature of 120°C , the maximum allowed TR is 80°C .

The importance of applying a proper insulation in the design of a specific electrical apparatus is hard to overestimate. The limit of temperature which the insulation is allowed to reach during service is also a limit to which a conductor under this insulation or touching this insulation may be heated. The whole design of electrical apparatus would be regulated and determined by this limit to not allow the temperature of the conductors surrounded by insulation to rise above this limit under any circumstances.

5.1.3 THERMAL DEGRADATION OF INSULATORS

The weakest and the fastest degrading component of any electrical equipment is the insulation. In cables, transformers, reactors, trip coils of CBs, operating coils of contactors, motors, and capacitors, the type of insulation used is solid synthetic and paper. The degradation of this insulation depends strongly upon the maximum temperature to which it is subjected. Various types of insulation are deteriorating at different rates while being exposed to elevated temperature, and an aging process is going on even if the exposure temperature is below the maximum temperatures defined by standards.

The longer the insulation material is under elevated temperature, the shorter the useful life of the insulation. In the electrical industry, there are some widely accepted terms that define the thermal performance of a material based on an accepted test method for electrical insulation materials.

Thermal endurance of insulation is defined as the relationship between temperature and the time spent at that temperature required for producing such degradation of an electrical insulation that it fails under specified conditions of stress, electric or mechanical, in service or under test (IEEE Standard Dictionary of Electrical and Electronic Terms [13]). The point of failure, also referred to as the “*Thermal Life*,” is typically considered the time at which the measured property falls below 50% of its original untreated value.

The so-called *relative temperature index* (RTI) characterizes an insulation system [14] and is obtained when a candidate insulation system is simultaneously tested with a known insulation system using identical conditions (e.g., the same

temperatures, time intervals, and oven). The *temperature index* according to ASTM Standard D2304 [15] is a number that permits a comparison of the temperature/time characteristics of an electrical insulation material, or a simple combination of materials, based on the temperature in degrees Celsius that is obtained by extrapolating the Arrhenius plot of life versus temperature to a specified time, usually 20,000 h.

Any analysis of the thermal performance of electrical insulation material should be based on the established test methods covered in IEEE, UL, NEMA, and ASTM standards. Table 5.2 shows the thermal class designations of insulation based on IEEE and IEC standards [8–10].

International IEC Standard 60216, “Electrical Insulating Materials—Thermal Endurance properties” [16], defines thermal aging processes and specifies the testing techniques for determining thermal endurance properties of electrical insulation materials. Temperature limits for paper insulation in liquid-immersed distribution, power, and regulating transformers have been established in IEEE Standard C57.12.00-2010 [17].

Test programs and methods for the determination of thermal performance of insulation materials were developed based on the assumption that heat is the chief cause of insulation degradation. Other factors being equal, thermal degradation is accelerated as the temperatures increases, and the other mechanical and electrical properties deteriorate with increasing temperature.

According to ASTM D2304, “Thermal degradation is often a major factor affecting the life of insulating materials and the equipment in which they are used.” The Standard also states that “Experience has shown that the thermal life is approximately halved for a 10°C increase in exposure temperature.”

Losing insulating properties under the influence of increased temperature is a major cause of insulation failure. For example, certain glasses and ceramics exhibit large increases in dielectric loss with increasing temperature. To determine thermal failure of solid electrical insulating material (EIM), various test procedure have been developed and standardized [18]. ASTM [19] established a method to determine thermal degradation of solid EIM.

5.1.4 TEMPERATURE LIMITATIONS FOR SWITCHGEAR ASSEMBLY BASED ON INSULATION CLASS

An example of temperature limitations for distribution power equipment determined by applied insulation can be learned from ANSI/IEEE Standard C37.20.2-1999, “IEEE Standard for Metal-Clad Switchgear” [20]. The metal-clad (MC) MV switchgear contains drawout electrically operated CBs; it is compartmentalized to isolate all the components such as instrumentation, main bus, and both incoming and outgoing connections with grounded metal barriers. In this Standard, temperature limitations and classification of the insulating materials used in switchgear are specified (Table 5.3).

The limiting temperature for the MC switchgear is the maximum temperature permitted for: (a) any component, such as insulation, buses, IT, and switching and interrupting devices; (b) air in cable termination compartments; (c) any noncurrent-carrying structural parts; and (d) the air surrounding the devices. The total

TABLE 5.3
Thermal Limits for Insulating Materials in MC Switchgear Assemblies

Class of Insulating Material	Limit of Hottest-Spot Total Temperature (°C)	Limit of Hottest-Spot Temperature Rise (°C)
90	90	50
105 (A)	105	65
130 (B)	130	90
155 (F)	155	115
180 (H)	180	140
220 (R)	220	180

Source: Modified from ANSI/IEEE Standard C37.20.2–1999, *IEEE Standard for Metal-Clad Switchgear*.
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temperature to which insulating materials are subjected shall not exceed the values defined for the various classes of insulating materials, based on the maximum ambient temperature 40°C.

5.2 AGING OF INSULATING MATERIALS DUE TO ELECTRICAL STRESS

Life of insulating materials strongly depends on the ability to resist deterioration under the influence of environmental factors, such as humidity, pollution (corrosive gases, particles, and dust), temperature changes, and others. In the case of electrical insulation, it is important to note that when in service, the insulation is exposed to multiple stresses: electric, thermal, and mechanical stresses (bending, vibration, etc.).

All the stresses the insulation is exposed to irreversibly change the material properties with the onset of time and thus reduce progressively the ability of the insulation to endure the stress itself. This process is called aging and ends when the insulation is no more able to withstand the applied stress. In the following sections several particularly damaging effects caused by the presence of electromagnetic field are described that shorten the life of the insulation. Various methods for monitoring the presence of harmful phenomena, maintenance techniques and corrective action to extend the life of insulation will be presented in the following parts of the book.

5.2.1 ELECTRICAL BREAKDOWN IN INSULATION

When the electric field is high enough, a dielectric material may suddenly lose its property of nonconduction, permanently or temporarily, showing an electrical breakdown. In other words, electrical breakdown is the result of a rapid reduction in the resistance of an electrical insulator that can lead to a spark jumping around or through the insulator. It may be a momentary event (as in an electrostatic discharge), or may lead to a continuous arc discharge if protective devices fail to interrupt the current in a high-power circuit.

The breakdown of the insulation of an electrical wire or other electrical components usually results in a short circuit or a blown fuse. This occurs at the breakdown voltage. Actual insulation breakdown is more generally found in HV applications, where it sometimes causes the opening of a protective CB. Electrical breakdown is often associated with the failure of solid or liquid insulating materials used inside HV transformers or capacitors in the electricity distribution grid. Electrical breakdown can also occur across the insulators that suspend overhead power lines, within underground power cables, or lines arcing to nearby branches of trees.

Under a sufficient electrical stress, electrical breakdown can occur within solids, liquids, gases, or vacuum. However, the specific breakdown mechanisms are significantly different for each kind of dielectric medium. All this leads to catastrophic failure of power equipment. During electrical “flashover”—arcing between conductors—the insulation is penetrated and usually destroyed by the particles of conducting material boiled off the conductors during the passage of current.

5.2.2 CORONA

5.2.2.1 Destructive Nature of Corona

This phenomenon received its name because it is visible to the unaided eye under certain conditions. A partial breakdown of the air occurs as a corona discharge on HV conductors at those points with highest electrical stress. Conductors which configuration includes sharp points, or balls with small radii, are more prone to dielectric breakdown.

Corona is sometimes seen as a glow around HV wires and heard as a sizzling sound along HV power lines. Corona also generates radio frequency noise that can also be heard as “static” or buzzing on radio receivers. A true corona involves only dielectric breakdown—ionization—of the air adjacent to a conductor. The heat that is generated during corona is too little to thermally break down the insulation material or to melt the conductors. No dielectric failure occurs within the insulation.

However, corona is destructive [21]. During corona, ionization of air converts oxygen to ozone, a highly reactive gas that chemically attacks insulation materials. In addition, physical bombardment of insulation surfaces by ionized air particles wears away the solid material as by sandblasting. This deterioration has several consequences. In coil insulation, prior to complete winding breakdown, a whitish residue, like mildew, may appear on end turn surfaces. This “powdering” consists of fine particles of insulation eroded away from coil surfaces. Coils later removed from the stator can show tape or wrapper sections eaten away as metal would be by corrosion. That is particularly true for polyesters. Corona discharges on rubber-based insulators, tape, and insulation board leave a white, fibrous power residue or dust (Figure 5.4) [22]. This dust is the result of physical breakdown of the material. The white power left by corona is conductive and it can support arcing conditions. Inside electrical components such as transformers, capacitors, electric motors, and generators corona progressively damages the insulation, leading to premature equipment failure. One form of attack is ozone cracking of elastomer items such as like O-rings.



FIGURE 5.4 White powder/dust residue formed on 13 kV power cables that are tie-wrapped together, forming tight air spaces between each other. (From Brady J. *Corona and Tracking Conditions in MC Switchgear Case Studies*, Online. Available: http://www.irinfo.org/articles/article_8_1_2006_Brady.pdf. With permission.)

5.2.2.2 Corona Tracking

The term “surface discharge” is also used for the sparking associated with “tracking” or current flow along the contaminated surfaces or end windings. Such tracking quickly leads to carbonization of insulation through local overheating. It will cause insulation damage much sooner than the mechanical or chemical erosion caused by air ionization (Figure 5.5a). Practically, once corona becomes active, it leaves behind a conductive “tracking” path on surfaces and also creates a very conductive cloud of air around itself. A flash-over can occur once a tracking pathway is completed

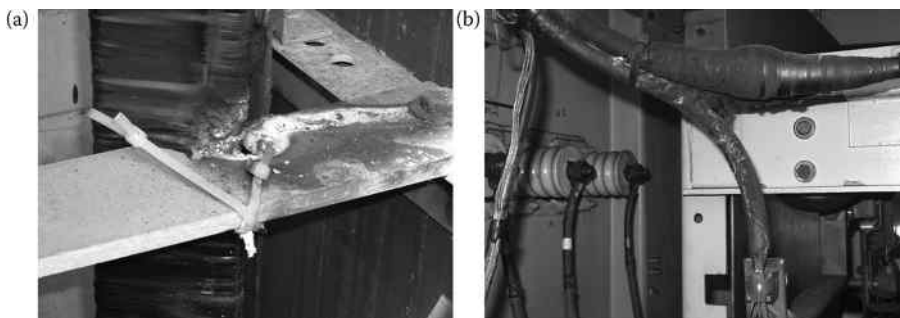


FIGURE 5.5 Advanced stage of carbon tracks on insulation board and insulated tape wrap on 4160 V bus (a); severely deteriorated power feed cable in 4160 V switchgear cabinet displaying white power and carbon tracks (b). (From Brady J. *Corona and Tracking Conditions in MC Switchgear Case Studies*, Online. Available: http://www.irinfo.org/articles/article_8_1_2006_Brady.pdf. With permission.)

from phase to phase or phase to ground [22]. It can also occur from the conductive cloud of the surrounding air once it finds a path to the ground. Three major causes for corona development should be considered: geometric factors, spatial factors, and contamination [22,23].

5.2.2.3 Corona in Switchgear

Geometric factors causing corona in switchgear include sharp edges on conductors, connections, and switchgear cabinet components. There are multiple locations within switchgear where corona may develop, such as sharp or squared tape wraps in conductor terminations, tag ends on conductors, and corners and points on cabinet bracing and support shelves. Spatial factors in switchgear include small air spaces between conductors, insulation board, and switchgear cabinet components. Lack of space may result from conductors being tie-wrapped together as well as from conductors touching insulators, conduit, and edges of cabinets. Corona may be initiated near nonshielded cables in contact with grounded surfaces or on bus bars in close proximity to fiber-resin supports and insulator material. Contamination such as dust, oils/fluids, and other particulates on conductors and insulators will also create corona.

Humid and wet conditions are very favorable for developing corona. Humid and wet conditions inside switchgear cabinets will allow nitric acid to form, which attacks the copper surface, leaving unusual weathering patterns. Cabinets lacking heaters, cabinets with poor weather seals, and those next to wet industrial processes are especially vulnerable to corona conditions.

As the corona condition worsens, carbon tracks develop on conductors and insulators. The distance between the phase and the ground will determine the time to reach a flash-over. In worst case scenarios, cables will be severely deteriorated (Figure 5.5b). Other indicators include discoloration and pitting on cable insulation. Usually, dull finishes and micro-crack stains on cable insulation will be noticed. Unusual weathering patterns on copper bus and conductors are also good indicators of corona (Figure 5.6).

5.2.3 PARTIAL DISCHARGE

In electrical engineering, *partial discharge* (PD) is a localized dielectric breakdown of a small portion of a solid or fluid electrical insulating system (EIS) under HV stress, which does not bridge the space between two conductors. While a corona discharge is usually revealed by a relatively steady glow or brush discharge in air, PDs within solid insulation system are not visible. PD can occur in a gaseous, liquid, or solid insulating medium. It often starts within gas voids, such as voids in solid epoxy insulation or bubbles in transformer oil. Protracted PD can erode solid insulation and eventually lead to the breakdown of insulation.

Therefore, the existence of the defects in insulating material, particularly the presence of voids and pores, usually leads to PD, which accelerates the process of aging of the insulator. PD usually begins not only within voids, cracks, or inclusions in a solid dielectric, but also at conductor–dielectric interfaces within solid dielectrics (Figure 5.7) [24,25]. PD can also occur along the boundary between different

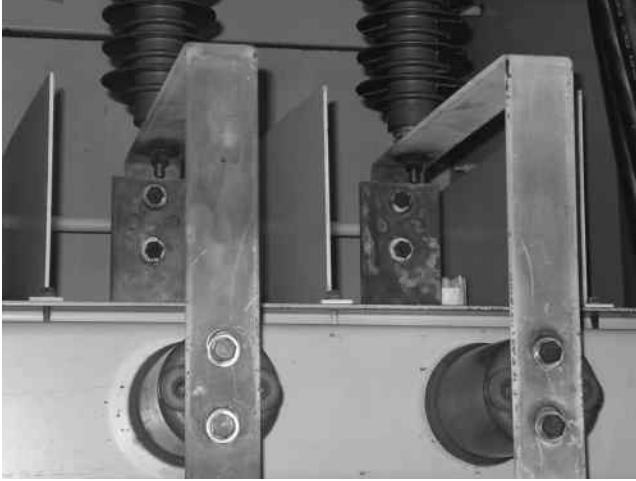


FIGURE 5.6 (See color insert.) Unusual weathering pattern on 13 kV copper bus under attack by corona produced nitric acid. (From Brady J. *Corona and Tracking Conditions in MC Switchgear Case Studies*, Online. Available: http://www.irinfo.org/articles/article_8_1_2006_Brady.pdf. With permission.)



FIGURE 5.7 (See color insert.) PD damage on a cast resin CB spout. (From Neil D. *Why PD measurement can pay dividends*, Online. Available: http://www.pennenergy.com/index/power/display/8315670195/articles/power-engineering-international/volume-18/Issue_3/features/Why_partial_discharge_measurement_can_pay_dividends.html. With permission.)

insulating materials and along the surface of solid insulating materials if the surface tangential electric field is high enough to cause a breakdown along the insulator surface.

This phenomenon commonly manifests itself on overhead line insulators, particularly on contaminated insulators during days of high humidity. Overhead line insulators use air as their insulation medium. Once begun, PD causes progressive deterioration of insulating materials, ultimately leading to electrical breakdown. The effects of PD within HV cables and equipment can be very serious, ultimately leading to complete failure. The cumulative effect of PDs within solid dielectrics is the formation of numerous, branching partially conducting discharge channels, a process called treeing.

Repetitive discharge events cause irreversible mechanical and chemical deterioration of the insulating material. The chemical transformation of the dielectric also tends to increase the electrical conductivity of the dielectric material surrounding the voids. This increases the electrical stress in the as yet unaffected gap region, accelerating the breakdown process. Damage is caused by the energy dissipated by high-energy electrons or ions, UV light from the discharges, ozone attacking the void walls, and cracking as the chemical breakdown processes liberate gases at high pressure.

The first solid insulation used for electrical applications was porcelain. A number of inorganic dielectrics, including glass, porcelain, and mica materials are very good insulators; they are also basically immune to electrical degradation, being significantly more resistant to PD damage than organic and polymer dielectrics. Nowadays solid insulation is often replaced by polymeric materials, which generally offer good electrical insulation properties. However, these materials are subject to surface aging and degradation processes. Any electrical activity on the surface of such materials causes tracking damage.

In practice, PD in HV/MV insulation exists in two forms, surface PD and internal PD. When surface PD is present, tracking occurs across the surface of the insulation, which is intensified by airborne contamination and moisture, leading to erosion of the insulation.

Surface degradation occurs as a result of the charring of the insulating material by electrical discharge according to the following scenario. The degradation is promoted by the presence of contaminants and/or moisture on the surface forming a conducting film on insulating parts, which allows a leakage current to permeate through the film. When this current is interrupted at a narrow point in the film, it results in a small discharge arc. High localized heating of the surface at the point of the arc produces a small spot of charred material. Further contamination of the surface allows the process to repeat until the spot becomes extended in lines in the direction of the field. Multiple permanent carbonized paths or lines caused by the degradation of the insulating material are formed on the surface of an insulator, resulting in a phase to earth fault.

Internal PD occurs within the bulk of insulation materials and is caused by age, poor materials, or poor-quality manufacturing processes. If allowed to continue unchecked, either mechanism of PD will lead to the failure of the insulation system, potentially resulting in catastrophic failure of the equipment.

5.2.3.1 Partial Discharge in Switchgear

PD activity has long been accepted as a major cause of failure of HV/MV switchgear [24,25], where during a temporary over-voltage, during an HV test, or under transient voltage conditions during operation PDs may occur on nonself-restoring insulation, which includes gas, liquid, and solid materials.

IEEE Standard 493-1997, “IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems—Gold Book” [26], concludes that “If these partial discharges are sustained due to poor materials, design, and/or foreign inclusions in the insulation, degradation and possible failure of the insulation structure may occur.” It has been found [27,28] that environmental conditions play a significant role in the inception and development of PD in switchgear.

High levels of relative humidity (RH) lead to an almost instantaneous increase in the levels of recorded surface PD, particularly when the moisture is condensed on the surfaces of the CB. It was observed that the PD activity could cease during dry periods, even during the advanced stages of damage to the cast resin insulation. It was also observed that the levels of RH correlate with the presence and magnitude of PD activity.

5.2.3.2 Partial Discharge in Paper-Insulated HV Cables

PD in HV cables begins as small pinholes penetrating the paper windings that are adjacent to the electrical conductor or outer sheath. As PD activity progresses, the repetitive discharges eventually cause permanent chemical changes within the affected paper layers and impregnating dielectric fluid [29]. Over time, partially conducting carbonized trees are formed. This places greater stress on the remaining insulation, leading to further growth of the damaged region, resistive heating along the tree, and further charring (also called *tracking*) (Figure 5.8). This eventually culminates in the complete dielectric failure of the cable and, typically, an electrical explosion.

PD generally dissipates energy in the form of heat. Sometimes, however, the energy is lost in the form of sound and light, such as the hissing and dim glowing from the overhead line insulators. Heat energy dissipation may cause thermal degradation of the insulation, although the level is generally low. For HV equipment, the integrity of the insulation can be confirmed by monitoring the PD activities that occur through the equipment’s life.

To ensure supply reliability and long-term operational sustainability, PD in HV electrical equipment should be monitored closely with early warning signals for inspection and maintenance. PD can be prevented through careful design and material selection. In critical HV equipment, the integrity of the insulation is confirmed using PD detection equipment during the manufacturing stage as well as periodically through the equipment’s useful life. PD prevention and detection are essential to ensure reliable, long-term operation of HV equipment used by electric power utilities.

There are several national and international Standards that define the techniques of PD evaluation and testing: (1) EC 60270:2000/BS EN 60270:2001, “High-Voltage Test Techniques—Partial Discharge Measurements”; (2) IEEE 400-2001, “IEEE Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems”; (3) IEEE 1434-2000, “IEEE Trial-Use Guide to the Measurement of Partial Discharges in Rotating Machinery.”

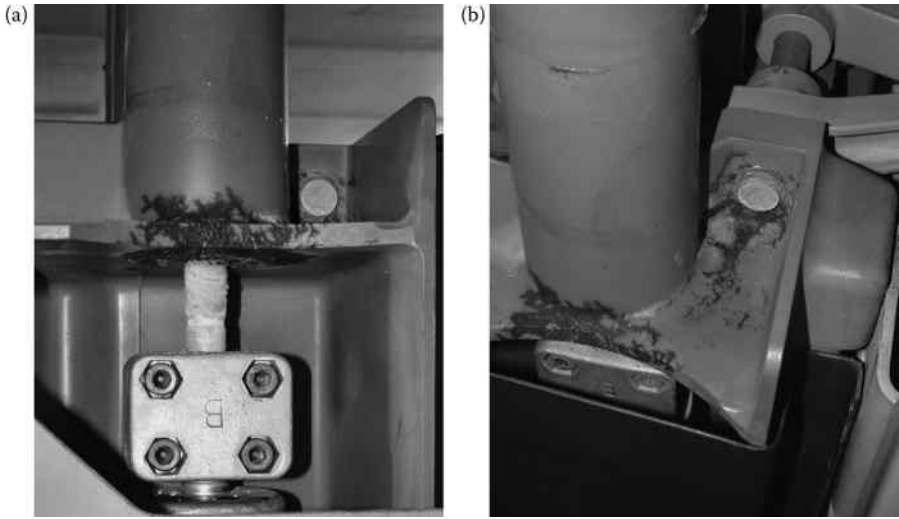


FIGURE 5.8 (See color insert.) Partial discharge tracking on CB insulation (a and b). (From Davies N. and Goldthorpe S. Testing distribution switchgear for partial discharge in the laboratory and the field, *Proceedings of 20th International Conference on Electricity Distribution*, CIRED 2009, Prague, 8–11 June 2009, paper 0804, Online. Available: http://www.cired.be/CIRED09/pdfs/CIRED2009_0804_Paper.pdf. With permission.)

5.3 ENVIRONMENTAL AGING OF INSULATING MATERIALS

The polymer insulator is constructed from two basic components, a core and weather shed. The core consists of a rod made of glass-fiber reinforced resin (Silicone Resin—SID) coupled to metal fittings at both ends. The rod is protected against external agents by polymeric sheds, which also provide the shape and leakage distance required for the rod to withstand electrical stresses.

The working and environmental conditions such as mechanical stresses, electrical fields, moisture, ozone, UV light, surface arcing, and contamination affect the performance of the polymeric insulators.

5.3.1 INSULATION DETERIORATION UNDER ENVIRONMENTAL CONDITIONS

Longevity of insulators depends on ability of the material to withstand detrimental effects of the environment, such as high humidity, pollution (corrosive gases, particles, and dust), cold and hot temperature, and their fast changes and other naturally existing factors. UV radiation and acid rain are the other sources of the aging caused by the surface chemical and structural changes derived from these stresses. Particulates deposited on the insulator surfaces can induce corona discharge and local TR may speed up insulator aging [30].

Different areas where electrical equipment is installed may differ significantly in what kind of pollution may be found on the surfaces of insulators, which cause destructive electrical discharges.

These areas are usually divided into several pollution categories: natural, industrial, and mixed. Natural surroundings are also different. In the inland environment, the source of pollution is mostly soil dust, which is not very conductive and adhesive and usually can be easily removed by natural and artificial washing. In the desert, sand may deposit on the surfaces and might have a high conductivity; some sands contain >20% of soluble material. In coastal areas where the wind carries sea water, salt crystals may form on the insulating surfaces. This deposit is not very adhesive and could be easily removed by natural and artificial washing.

In industrial areas, pollution is much worse. If electrical equipment is installed near or at steel mills, coke plants, cement factories, chemical plants, paper mills, generating stations, quarries, and so on, the deposits coming from the industrial atmosphere may be highly conductive and often combine with insoluble materials. When an industrial facility is located close to the sea coast or in the desert, these pollution factors combine and may produce very adhesive and very conductive deposits.

In the study of aging of silicon rubber (SIR) [5], it was shown that oxidation and formation of by-products of oxidation are the most dominant chemical reactions during the aging of SIR.

5.3.2 BIOLOGICAL CONTAMINATION AND CORROSION OF INSULATORS

In the tropical condition, bio-films may grow on silicone rubber insulators. The earlier experience was with finding a biological growth [31] on SIR insulators in Sri Lanka, but a similar contamination is frequent in other parts of the world [32,33]. Intensive biological growth of algae and fungus was found on energized insulators. The contaminants are usually present on the upper sides of the sheds, except for the top ones. In most cases, the contaminant covered the shed area almost completely.

In the marine environment, sea spray, mist or fog can carry sodium chloride several miles from the coast, which makes the installations located a substantial distance from the ocean vulnerable. It is found that exposure to high humidity and intensive salt contamination leads to corrosion of metallic connections between the tower and the insulator end-fittings as well as insulator end-fittings [31], although the salt deposits are not often visible on the insulators because it is easily removed by rains.

5.3.3 ENVIRONMENTAL AGING OF INSULATORS IN TRANSMISSION LINES

Overhead transmission or distribution lines are widely used in the present power system to transmit electric power from generation stations to customer points. Their proper function largely depends on the insulation system with the supporting structures [34]. The performance of outdoor insulators, as the main insulating material, is influenced by many environmental parameters. Two of these parameters are pollution and humidity.

Transmission lines sometimes pass through many polluted or emitted areas, such as coastal, industrial, and even geothermal areas. In the particular case of geothermal areas, transmission lines are used to transmit electric energy from a geothermal power plant (GTPP) to a switchyard of distribution. Geothermal power stations

TABLE 5.4
The Composition of Pollution Deposit on Insulator Surface

Element	Amount (%)	Element	Amount (%)	Element	Amount (%)
C	61.23	Cu	5.82	S	2.40
Si	11.92	Fe	5.63	K	1.33
Al	6.81	Ca	4.32	V	0.54

Source: Modified from Waluyo, Ngapuli I. S., Suwarno, and Djauhari M. A., *ECTI Trans. Electr. Eng. Electron. Commun.* 8(1), 126–145, 2010.

create emission as chemical materials. Most chemical compounds are present in gaseous form, especially CO₂ (94–98%) and H₂S (1%) [33].

Geothermal liquids (steam or hot water) usually contain gases, such as CO₂, H₂S, NH₃, CH₄, and trace amounts of other gases, as well as dissolved chemicals whose concentrations usually increase with temperature. For examples, sodium chloride (NaCl), boron (B), arsenic (As), and mercury (Hg) are sources of pollution if discharged into the environment [35].

GTPP could release the following pollutants: CO₂ (98%), H₂S (1.5%), methane (0.4%), and hydrogen (0.1%). The oxidation of H₂S to SO₂ and its subsequent reaction with sulfate ions produces aerosols representing a major component of acid rain. GTPP could also release trace amounts (0.001%) of ammonia, radon, boron, arsenic, cadmium, and antimony. Ammonia and mercury may also enter local waters from geothermal steam condensation [35].

All these pollutants dissolved in water could easily deposit on the surface of insulators and eventually destroy it. An example of the composition of sticky pollutants found on the surface of insulators in Kamojang switchyard (in Thailand) is given in Table 5.4 [35], which shows that pollution contains many elements (metallic and nonmetallic), whose compounds could be very chemically active and harmful.

5.3.4 STRESS CORROSION CRACKING IN COMPOSITE INSULATORS

Non-ceramic insulators (NCI), also referred to as composite or polymeric insulators, are used in overhead transmission lines (OHTL) with line voltages in the range of 69–735 kV. Despite the many benefits that NCI offer in comparison with their porcelain counterparts, they can fail mechanically in service by rod fracture. One of the mechanical failure modes of the insulators is a failure process called brittle fracture, which is caused by the SCC of the glass-reinforced plastic (GRP) rods.

It was found [36] based on experimental evidence that brittle fracture failures of composite (nonceramic) HV insulators could be caused by water and mechanical stresses. However, in refs. [37,38], it has been clearly shown that only water, in the absence of electrical field, cannot cause SCC of unidirectional E-glass/polymer composites and thus brittle fracture of composite NCI. It was rather seen as a cumulative

effect of the formation of nitric acid in service through corona discharges, ozone, and moisture.

The process is catastrophic and unpredictable, leading to the drop in energized transmission lines. The most important characteristic of the brittle fracture process is that it can occasionally affect HV nonceramic transmission line insulators, leading to their catastrophic in-service failures [39,40].

To prevent brittle fracture, water or nitric acid must never be allowed inside the insulators; however, it is difficult to effectively provide for long periods of time considering the harsh nature of the environment in the vicinity of the energized ends of the insulators (nitric acid, pollution, acid rain, ozone, corona discharges, etc). It can be expected that even the best shielding against moisture ingress will sooner or later fail to protect the insulators. Some manufacturers are making every effort to design such a protection in the best way they can [39]. However, it might be a better solution to develop an insulator with a high resistance to brittle fracture.

5.4 HV BUSHINGS IN TRANSFORMERS AND CBs

Bushing is a very important component in the design of switchgear, CBs and transformers. It is a hollow insulator, allowing a conductor to pass along its center and connect at both ends to other conductive elements. Bushings are often made of wet-process fired porcelain, and may be coated with a semiconducting glaze to assist in equalizing the electrical stress along the length of the bushing. The inside of the bushing may contain paper insulation and the bushing is often filled with oil to provide additional insulation.

Bushings for MV and LV apparatus may be made of resins reinforced with paper. The use of polymer bushings for HV applications is becoming more common. The largest HV bushings made are usually associated with HV direct-current converters.

Some of the HV types are called capacitor bushings because they form a low-value capacitor between the conductor and the wall. They are made of layers of conductive paper, film, ink or aluminum foil with an insulating medium. This is done to reduce the electrical field stress that would otherwise occur and cause breakdown.

5.4.1 TYPES OF BUSHINGS

HV bushings manufactured for use on transformers and breakers are of several types [41]:

- A. *Composite Bushing*—A bushing in which insulation consists of two or more coaxial layers of different insulating materials.
- B. *Compound-Filled Bushing*—A bushing in which the space between the major insulation (or the conductor where no major insulation is used) and the inside surface of a protective weather casing (usually porcelain) is filled with a compound having insulating properties.
- C. *Condenser Bushing*—A bushing in which cylindrical conducting layers are arranged coaxially with the conductor within the insulating material. The length and diameter of the cylinders are designed to control the distribution



FIGURE 5.9 Porcelain dry-type bushings in ratings from 15 to 38 kV. (From Piedmont Bushings & Insulators, Online. Available: http://www.pb-i.com/images/4bushings_1.jpg. With permission.)

of the electric field in and over the outer surface of the bushing. Condenser bushings may be one of several types: resin-bonded paper insulation; oil-impregnated paper insulation; or others.

- D. *Dry or Unfilled Type Bushing*—Consists of porcelain tube with no filler in the space between the shell and conductor. These bushing are usually available from 38 kV and below (Figure 5.9).
- F. *Oil-Filled Bushing*—A bushing in which the space between the major insulation (or the conductor where no major insulation is used) and the inside surface of a protective weather casing (usually porcelain) is filled with insulating oil.
- G. *Oil Immersed Bushing*—A bushing composed of a system of major insulations totally immersed in a bath of insulating oil.
- H. *Oil-Impregnated Paper-Insulated Bushing*—A bushing in which the internal structure is made of cellulose material impregnated with oil.
- I. *Resin-Bonded, Paper-Insulated Bushing*—A bushing in which the major insulation is provided by cellulose material bonded with resin.

5.4.2 BUSHINGS: POSSIBLE CAUSES OF FAILURES

About 90% of all preventable bushing failures are caused by moisture entering the bushing through leaky gaskets or other openings according to operating records [41]. Table 5.5 shows the defects found in the bushings and common causes of bushing failures. Bushing failures may cause very costly outages. HV bushings, if allowed to

TABLE 5.5
Bushing Defects and Possible Causes of the Failure

Bushing Defects	Possible Causes of the Failure
Cracks in porcelain, deterioration of cemented joints	Moisture inside bushing, oil, gas or filler leaks.
Gasket leaks, moisture in insulation, solder seal leak	Moisture inside bushing, oil, gas or filler leaks.
Broken connection between ground sleeve and flange	Sparking in apparatus tank or within bushing.
	Discolored oil.
Voids in compound	Internal corona.
Oil migration	Filler contamination.
No oil	Oil leaks out. Moisture enters.
Displaced grading shield	Internal sparking discolors oil.
Electrical flashover, lightning	Cracked or broken porcelain.
Corona	Internal breakdown. Radio interference. Treeing along surface of paper or internal surfaces.
Short-circuited condenser sections	Increased capacitance. Reduced voltage at capacitance tap terminal. Internal stress to insulation.
Darkened oil	Radio interference, poor test results.

Source: From Facilities instructions, standards, and techniques. In *Testing and Maintenance of High-Voltage Bushings*, Vol. 3–2, US Department of the Interior Bureau of Reclamation, 1991.

deteriorate, may explode with considerable violence and cause extensive damages to adjacent equipment.

After long exposure to all stresses, multiple chips, cracks, and contamination may be found on the surface of porcelain bushings. Minor chips may be painted with an insulating varnish to obtain a glossy finish which will shed dirt and moisture. Bushings with major chips or cracks can no longer stay in service since these defects significantly decrease the creepage distance.

Deposits of dirt on the bushings, particularly in areas where there are contaminants such as salts or conducting dusts in the air, may cause flashovers. These deposits should be removed by periodic cleaning of the surface of the porcelain to remove dirt, oil, and other deposits that may reduce the flashover value. Multiple tests are recommended to determine the physical condition of the bushings [41,42].

5.5 POWER CABLE INSULATION

The power cable is an essential part of any electrical system. Power cables may be installed as permanent wiring within buildings, buried in the ground, made to run overhead, or exposed. Cables consist of three major components: conductors, insulation, and a protective jacket.

The construction and material of individual cables vary according to the application and are determined by several major factors: working voltage, current-carrying capacity, and environmental conditions such as temperature, water, chemical, or sunlight exposure, and mechanical impact. The thickness of the insulation is determined

by working voltage, while the cross-sectional size of the conductor(s) is determined based on the current-carrying capacity. The form and composition of the outer cable jacket is usually chosen based on the environmental conditions where the cable would be installed.

Power cables use stranded copper or aluminum conductors, although small power cables may use solid conductors. Some power cables for outdoor overhead use may have no overall sheath. Other cables may have a plastic or metal sheath enclosing all the conductors. The materials for the sheath will be selected for resistance to water, oil, sunlight, underground conditions, chemical vapors, impact, or high temperatures.

In nuclear industry applications, the cable may have to meet special requirements for ionizing radiation resistance. It may be specified that the cable materials should not produce large amounts of smoke if burned. Cables intended for underground use or direct burial in earth will have heavy plastic or metal, most often lead sheaths, or may require special direct-buried construction. When cables must run where they are exposed to mechanical impact damage, they may be protected with flexible steel tape or wire armor, which may also be covered by a water-resistant jacket.

There are many types of cables depending on voltage and application. MV cables may be used for underground residential distribution (URD) (15–35 kV), as cable in conduit (CIC), as a single or multiconductor (5–69 kV), as armored submarine cable, mining cable, and so on. A paper-insulated underground distribution cable carries power ranging from 5 to 46 kV, and a paper-insulated underground transmission cable carries power ranging from 69 to 345 kV.

5.5.1 CABLE INSULATION TYPES

Electrical insulation materials are used over the metallic conductors of underground cables at all voltage ratings. *Paper* insulation was used first in the power industry, and was later replaced in LV and MV applications with polymeric materials, but the nature of the polymer may vary with the voltage class. After synthetic polymer development, *PE* and *cross linked polyethylene* (XLPE) have been used as insulation material; the latter version is used in most countries.

XLPE is considered to be the material of choice due to its ease of processing and handling. A version of XLPE insulation is Tree-Retardant Cross-Linked Polyethylene (TR-XLPE). Another insulation synthetic material used for insulation is *ethylene propylene rubber* (EPR).

Cables for transmission are operating above 46 kV; they have traditionally used paper and oil systems as the insulation. The paper is applied as a thin film wound over the cable core. A variation of paper insulation was developed as a *laminate of paper with polypropylene* (PPP or PPLP), and PILC cables are paper insulated with lead-sheathed cables. MV power cables operate in the voltage range of 5–45 kV and the following types of cables are used more often than others: XLPE insulated power cables; paper-insulated power cables; EPR trailing cables for mines; and bundle conductors MV XLPE types.

Cables with paper-impregnated insulation have served the consumers and industry extremely well; they are reliable and continue operating for up to 40 years. With

the introduction of the cables with XLPE insulation, the sales pitch was that these cables could be laid into an unprepared trench and would survive.

The first generation of XLPE cables (before 1980) were badly constructed with tape or loose core screens. The latest PVC or XLPE cables can be as reliable as cables with paper-impregnated insulation, provided they are correctly installed and maintained. Solid dielectric cables will eventually replace the cables with paper-impregnated insulation.

5.5.2 AGING OF CABLE INSULATING MATERIALS

Many cables as a part of electric power systems have been manufactured and installed over many decades. The oldest oil-paper insulated cables still in use were installed in the 1940s. Installation of XLPE cables started in the middle of the 1970s. Some of the oil-paper insulated cables are rather old and the first XLPE cables are old enough to show possible degradation results. The insulation systems of power cables and their accessories are subject to different kinds of stresses during their service life and thus suffer degradation. This can lead to a reduction of life, which in turn can lower the reliability of electrical power systems.

Aging of insulation in MV and HV cables is caused by the same factors as solid insulation: electrical and mechanical stresses and environmental deterioration. One of the most serious electrical stresses leading to significant deterioration of insulation in power cables is PD, which eventually results in failure.

5.5.2.1 XLPE Cable Insulation Degradation

The degradation processes of XLPE insulation can be categorized into two main groups: (1) due to voids, contaminants, physical imperfections, or poorly dispersed components; and (2) due to physical or chemical changes or trapped charges in the cables [43–46], many of them leading to *thermal* degradation of the insulation. During normal operation, cable XLPE insulation temperatures should be below 90°C, while during fault conditions cables should withstand temperatures of up to 120°C. At temperatures between 150°C and 225°C, chemical changes are activated in the polymer, which decrease the mechanical strength and the density of insulation. At temperatures higher than 225°C, chemical deterioration is detected, which further damages the insulating properties.

Residual internal *mechanical* stresses from manufacturing have a significant effect on the breakdown strength of cable insulation [44].

The most dangerous defects in polymeric insulation are caused by *electrical* degradation. PDs, electrical trees and water trees are the most important mechanisms. Defects in insulation structure increase the effect of electrical degradation and the risk of electrical breakdown. Polymeric insulation is sensitive even to small PDs [45]. Small cavities or gas bubbles can form inside the insulation or in the surface between insulation layers during the manufacturing or installation of accessories on the cable. When the electric field inside a cavity or bubble is high enough, partial breakdown will occur.

PDs in one location within the cable insulation will lead to an electrical degradation that affects the insulation locally and randomly. Electrical degradation does not affect the whole cable as thermal degradation does. The defect leading to final

breakdown will usually be a local phenomenon. Low electric field intensity and long development time are common for electrical degradation mechanisms in MV cables.

5.5.2.2 Electrical and Water Treeing

An electrical tree is a network of fine conductive channels that spreads relatively quickly through the insulation to cause failure. *Electrical trees* can “grow” from the eroded surface of the void or in the micro cavities of the polymer. They develop further from the expanded void due to the PDs within the branches. The tree growth rate depends on the applied electrical stress, the temperature, and the environmental and mechanical stresses [45,46].

The majority of XLPE insulated cables installed in the ground are exposed to moisture. The result is another degradation process called *water trees*. Water trees are generally found to initiate and grow in XLPE insulation exposed to an alternating electric field and humidity. Impurities inside the insulation material increase the risk of water tree formation. Water can penetrate the insulation from the outside of the cable if water-blocking barriers are not used. Water can also enter cable insulation from termination or joint faults. Moisture inside the insulation will start to propagate in the direction of the electric field in a bush or tree form.

Growth of the water trees depends on the presence of water, the intensity and frequency of the electric field, the insulation material, temperature, and mechanical stresses. Total breakdown of the insulation can happen when a branch of a water tree bridges the electrodes. The underground cables installed in moist environments should be protected against moisture penetration into the insulation.

5.6 OTHER INSULATING MEDIA

5.6.1 INSULATING OIL

The dielectric oil functions are to insulate, suppress corona and arcing, and to serve as a coolant. Therefore, insulating oil should remain stable at high temperatures for an extended period of time. Insulating oil is usually a highly refined mineral, vegetable or synthetic oil that is stable at high temperatures and has excellent electrical dielectric properties. It is used in oil-filled transformers, some types of HV capacitors, and some types of HV switches and CBs.

5.6.1.1 Transformer Oil

The purpose of using oil in a transformer is to cool it. To improve the cooling of large power transformers, the oil-filled tank may have external radiators through which the oil circulates by natural convection. Very large or high-power transformers (with the capacities of thousands of KVA) may also have cooling fans, oil pumps, and even oil-to-water heat exchangers. To ensure that the transformer is completely free of water vapor before the cooling oil is introduced, large HV transformers undergo prolonged drying processes, using electrical self-heating, the application of a vacuum, or both. This helps prevent corona formation and subsequent electrical breakdown under load. The oil also provides electrical insulation between internal live parts.

Multiple gases are produced in the oil as a side effect of corona or an electric arc in the windings. Oil-filled transformers with a conservator (an oil tank above the transformer) tend to be equipped with safety devices (Buchholz relays) that detect the build-up of gases (such as acetylene) inside the transformer and switch off the transformer. Transformers without conservators are usually equipped with sudden pressure relays, which perform a similar function as the Buchholz relay.

5.6.1.2 Oil Switches and CBs

Mineral transformer oil is used for interrupting and cooling an electrical arc. Oil circuit breakers (OCBs) are CBs that have their contacts immersed in oil. Current interruption takes place in oil, which cools the arc developing during interruption, and thereby oil quenches the arc. Because of the high temperature of the arc, the oil is evaporated rapidly and oil vapors are partially decomposed, producing ethylene, methane, and other gases. A gas bubble is formed in the arcing zone; the pressure in the bubble is very high. The arc is then extinguished, both because of its elongation upon the parting of contacts and because of intensive cooling by the gases and oil vapor.

There are two types of oil-filled switches and CBs: (1) tank-type oil and (2) oil-minimum or low-oil-capacity. In the first type, the main contacts and the arc-quenching devices are located in a grounded metal tank; in the second type, they are in an insulating or ungrounded metal enclosure filled with oil. Tank-type OCBs are inferior to other types of HV breakers in many respects. However, their low cost and high reliability have led to their continued use.

5.6.1.3 Aging of Transformer Oil

Where oil is used as insulating media, there are multiple mechanisms of oil aging and deterioration, such as ingress of moisture, ingress of air, and over-saturation with gas. Aging oil displays thermal instability and is often contaminated with metal-containing colloids and particles. All these oil-deteriorating processes affect the performance of the electrical machine. One of the most important aging mechanisms is decomposition of the oil itself during arc interruption and overheating, which leads to deterioration of its dielectric properties. The second important aging problem is the deposition of conductive and polar particles accumulating in oil during the service. These particles form a deposit on the solid insulation of the parts, leading to insulation surface contamination, which causes a distortion of electrical field and a reduction in the electrical strength of the insulation system [47,48]. For more about transformer oil aging, see Section 7.3.

There are several transformer oil tests that should be periodically performed to determine the condition of a transformer oil.

5.6.1.3.1 Dissolved Gas Analysis

Determines the types and concentrations of the gases dissolved in transformer oils. The gases are generated in the oil due to the breakdown of the paper or oil under stress or degradation. With regular dissolved gas analysis (DGA) testing, multiple problems can be detected months in advance.

5.6.1.3.2 *Furanic Analysis*

Determines the concentration of furans in transformer oils. Furans are degradation products of the insulation paper found in transformers. Analysis of furans is important in predicting the degradation of the insulating paper.

5.6.1.3.3 *Polychlorinated Biphenyl Analysis*

Determines the amount of Polychlorinated biphenyl in transformer oils. Polychlorinated biphenyls are toxic compounds; their quantity in transformer oils is usually regulated and should not be exceeded.

5.6.1.3.4 *Corrosive Sulfur Analysis*

Determines the amount of sulfur in the oil. Sulfur reacts with copper conductors and silver contacts to form metal sulfides that contaminate the insulating paper; sulfur also forms acidic conditions in transformers. If corrosive sulfur is found, oil will need to be replaced.

5.6.1.3.5 *Moisture Content*

Determining the moisture content in transformer oils allows finding out whether there are any leaks in the transformer, and the increase in moisture indicates insulating paper degradation.

5.6.1.3.6 *Total Acid Number*

Total acid number (TAN) is the quantity of base (mg of KOH) that is required for neutralizing acid constituents in 1 g of a sample. An increase in acid indicates that sludge formation is beginning to occur or is occurring.

5.6.1.3.7 *Dielectric Strength*

Dielectric strength is the voltage at which breakdown of the oil occurs. Insulating power decreases as the amount of contaminants in the transformer oil increases, so the insulating quality of the oil can be predicted.

5.6.1.4 **Thermal and Electrical Faults of Transformer Oil**

At high temperatures, a transformer oil ages rapidly; however, there are multiple factors that accelerate oil aging, such as moisture, copper, paint, varnish, and oxygen. There are limits for the oil temperature of transformers and bushings that are defined by the standards.

ANSI/IEEE Standard C57.12.00-2010, “General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers” [17], states that the ambient temperature shall average 30°C, and the average winding temperature rise (TR) shall not exceed 65°C. This would mean that the top transformer oil will average 95°C in a 24 h period. Another transformer standard ANSI/IEEE C57.12.10-1997 determines top-liquid temperature-range limits. It states that the transformer shall be suitable for operation over a range of top-liquid temperatures from -20°C to +105°C, provided that the liquid level has been properly adjusted to the indicated 25°C level. The bushing standard ANSI/IEEE C57.19.00-2004, “General Requirements and Test

Procedure for Power Apparatus Bushings,” states that the temperature of the ambient air should not be above 40°C or below -30°C, and the temperature of the transformer insulating oil in which the lower end of the bushing is immersed and the bushing mounting surface does not exceed 95°C averaged over a 24 h period. This means that exceeding the maximum standard temperature 95°C of transformer oil for prolonged periods of time would lead to accelerated aging of the oil.

The principal mechanism of transformer oil aging is oxidation, which results in the formation of acids and other polar compounds. A transformer oil, when subjected to thermal and electrical stresses in an oxidizing atmosphere, gradually loses its stability and becomes decomposed and oxidized; its acidity increases and finally it begins to produce mud [49].

At oil temperatures from 150°C to 300°C, relatively large quantities of the low-molecular-weight gases, such as hydrogen (H_2) and methane (CH_4), and trace quantities of the higher-molecular-weight gases ethylene (C_2H_4) and ethane (C_2H_6) are produced by poor cooling or stray losses in winding or leads; between core laminations or in core, tank, or supporting structures.

As the temperature of mineral oil increases from 300°C to 700°C, the hydrogen concentration exceeds that of methane and is accompanied by significant quantities of higher-molecular-weight gases, first ethane and then ethylene. Beyond 700°C (the upper end of the thermal fault range), increasing quantities of hydrogen and ethylene and traces of acetylene (C_2H_2) may be produced. In general, nonelectrical thermal faults produce temperatures below 700°C; however, welding on oil-filled equipment or oily surfaces produces acetylene due to the very high temperature [50].

Under the conditions of normal transformer functioning, aging can occur at a slow pace; however, this process is accelerating under continuous electrical and thermal faults. Aging transformer oil contains various soluble hydrocarbon gases, such as methane, ethane, ethylene, acetylene, and propane, along with carbon monoxide, carbon dioxide, hydrogen, oxygen, and nitrogen [49]. Concentration and the rate of gas generation usually depend on fault characteristics, such as type and intensity.

The most important dissolved gases in transformer oil to watch are combustible gases such as hydrogen, acetylene, carbon monoxide, and carbon dioxide. An increase in the generation of dissolved combustible gases is also caused by high temperatures of transformer oil, which may happen if the cooling system failed or is not operating automatically.

Electrical faults range in energy and temperature from intermittent low-energy PDs to steady discharges of high energy (arcing). As the discharge progresses from low energy to higher energy, the acetylene and ethylene concentrations rise significantly. PDs at low temperature (150–300°C) mainly produce hydrogen, with lesser quantities of methane and trace quantities of acetylene. Some thermal decomposition of oil and cellulose is observed in this temperature range.

Arcing and continuing discharge at low and high energy generate temperatures ranging from 700°C to 1800°C, at which acetylene is produced. National and international Standards are developed to define the factors of oil deterioration and the means of testing and controlling the degree of oil aging [50,51]. Typical defects and failure mechanisms of oil-filled electrical equipment and various means of testing will be presented in the following parts of the book.

5.6.2 SULFUR HEXAFLUORIDE (SF_6) AS INSULATING AND COOLING MEDIA

SF_6 is used as an insulating gas in substations, as an insulating and cooling medium in transformers, and as an insulating and arc-quenching medium in switchgear for HV and MV applications. These are all closed systems which are extremely safe and unlikely to leak.

The gas-insulated substations (GIS) use a superior dielectric gas, sulfur hexafluoride (SF_6), at moderate pressure for phase-to-phase and phase-to-ground insulation. Because of much better dielectric properties of SF_6 gas, GIS can be much smaller than air-insulated substations (AIS). A GIS is mostly used where space is expensive or not available. In a GIS the active parts are protected from the deterioration caused by exposure to atmospheric air, moisture, contamination, and so on. As a result, a GIS is more reliable and requires less maintenance than AIS.

In the breakers filled with SF_6 , the gas provides electrical insulation and effectively controls arcing. The HV conductors, CB interrupters, switches, current transformers, and voltage transformers (VTs) are enveloped in SF_6 gas inside grounded metal enclosures.

5.6.2.1 Insulating Properties and Decomposition of SF_6

SF_6 is an inert, nontoxic, colorless, odorless, tasteless, and nonflammable gas consisting of a sulfur atom surrounded by and tightly bonded to six fluorine atoms. It is about five times as dense as air. SF_6 has a dielectric withstand capability 2.5 times better than air. Usually the gas is used at 3–5 times atmospheric pressure and then the dielectric properties are 10 times better than for air. The pressure is chosen so that the SF_6 will not condense into a liquid at the lowest temperatures the equipment experiences. It is the universally used interrupting medium for HV CBs, replacing the older media of oil and air [52,53].

SF_6 gas is very stable, but it will partly decompose in association with electric discharges and arcs, for example, in a breaker. Some reactive decomposition by-products are formed because of the trace presence of moisture, air, and other contaminants. Then, gaseous and solid decomposition products are produced. Normally the level of gaseous decomposition products is kept low through the use of absorbers built into the switchgear. In large concentrations, the decomposition products are corrosive and poisonous. Therefore, there are established routines for service personnel when opening SF_6 -filled equipment for maintenance or scrapping.

The solid decomposition products are mainly metal fluorides in the form of a fine grey powder. The powder only appears where arcing has occurred, for instance in used CBs. The powder can be easily taken care of as separate waste. The decomposition products are reactive, which means that they will decompose quickly and disappear without any long-term effect on the environment.

In modern GIS, SF_6 gas is contained for the entire lifetime of the equipment; there is no need to open the equipment for servicing and no gas can escape. The quantities of decomposition products are very small. Molecular sieve absorbents inside the GIS enclosure eliminate these reactive by-products. Small conducting particles significantly reduce the dielectric strength of SF_6 gas. The particles are moved by the electric field, possibly to the higher-field regions inside the equipment or deposited

along the surface of the solid epoxy support insulators, leading to dielectric breakdown at operating voltage levels. Cleanliness in assembly is therefore very important for GIS [54].

5.6.2.2 SF₆ as a Greenhouse Gas

SF₆ is a strong greenhouse gas that could contribute to global warming. At an International Treaty Conference in Kyoto in 1997, SF₆ was listed as one of the six greenhouse gases whose emissions should be reduced. SF₆ is a very minor contributor to the total amount of greenhouse gases due to human activity, but it has a very long life in the atmosphere (the half-life is estimated at 3200 years), so the effect of SF₆ released to the atmosphere is effectively cumulative and permanent [55].

The major use of SF₆ is in electrical power equipment. However, SF₆ gas is contained in closed systems—in many cases, sealed for life. Major manufacturing companies produce the products with guaranteed leakage rates below 0.5%/year and the next generation should lose <0.1%/year. Accidental escapes of SF₆—due to mistakes during manufacturing, installation, maintenance, and decommissioning—are a bigger problem than leaks. In GIS, SF₆ is contained and can be recycled. According to international guidelines on the use of SF₆ in electrical equipment, the contribution of SF₆ to global warming can be kept at <0.1% over a 100-year horizon [56].

The emission rate of SF₆ due to the use in electrical equipment has been reduced over the last several years. Most of this reduction has been simply due to the adoption of better handling and recycling practices. Standards now require GIS to leak <1%/year. The leakage rate is normally much lower. Field checks of GIS in service for many years indicate that the leak rate objective can be as low as 0.1%/year when GIS standards are revised.

5.6.3 AIR AND VACUUM AS INSULATING MEDIA

The atmospheric *air* is used in air-insulated CB and substations (AIS) as insulating media. Miniature LV CBs use the air alone to extinguish the arc. Larger ratings will have metal plates or nonmetallic arc chutes to divide and cool the arc. Magnetic blowout coils or permanent magnets deflect the arc into the arc chute. Air CBs use compressed air (puff) to blow out the arc, or alternatively, the contacts are rapidly swung into a small sealed chamber escaping displaced air by blowing out the arc (air-magnetic and air-blast CBs).

The development of medium and high CBs using *vacuum* as arc interrupting media began in the United States and England in the 1950s. The benefits of using vacuum in circuit interrupters are all based on the unusual dielectric properties of vacuum. Vacuum has a minuscule number of possible charge carriers (atoms and molecules); therefore, there is practically no capability to have an electrical breakdown or lower vacuum ability of quenching an arc between electrical contacts when they separate. Vacuum has a very high dielectric strength and a high natural interruption capability [57].

The principle of interrupting of AC currents by vacuum arcs is mainly used in LV and MV CBs at voltage rating up to 40.5 kV; application of vacuum at very high

voltage above 72 kV is rare [58]. When the contacts separate in vacuum circuit breakers (VCB), the current flowing through electrodes initiates a metallic vapor discharge in the contact called the vacuum arc. The arc is then extinguished and the conductive metal vapor condenses on the metal surfaces. Another benefit of using vacuum in CBs is that there is no risk to the environment compared with SF₆ CBs [59].

The worst cause of failure of vacuum interrupters is the leak that allows air to get inside the vacuum interrupter, thus increasing the pressure inside and creating the means for electrical breakdown. Failures related to the CB interrupter chamber losing vacuum are very rare, and these devices are very reliable and safe. However, vacuum arc creates metallic vapor, which deposits on the surfaces of insulation in vacuum interrupters, thus significantly decreasing the dielectric performance of the ceramic envelope usually made of high-purity alumina (Al₂O₃). This deposition may eventually lead to the failure of the insulation; however, the density of the vapor in the arc is extremely low [60] and various designs of vacuum interrupters may confer protection of the ceramic surface against metal vapor condensation [61].

5.7 POWDER COATING AND PAINT FOR ELECTRICAL ENCLOSURES

5.7.1 ELECTRICAL ENCLOSURES: TYPES AND MATERIALS

Electrical equipment should be protected from the adverse influence of the environment, particularly when they are exposed to a polluted industrial atmosphere or installed outdoor. Therefore, electrical machines are locked in boxes or enclosures that are made from many different materials, such as steel, aluminum, polyester, polycarbonate, and so on [62]. The NEMA and UL established a rating system that guarantees that an enclosure meets certain minimum conditions of corrosion resistance [63]. In [Tables 5.6](#) and [5.7](#), different types of outdoor and indoor enclosures are listed together with the degree of protection from specific conditions.

Some types of electrical enclosures are not listed in [Table 5.6](#). In hazardous locations, Type 7 and 10 enclosures are designed to contain an internal explosion without causing an external hazard. Type 8 enclosures are designed to prevent combustion through the use of oil-immersed equipment. Type 9 enclosures are designed to prevent the ignition of combustible dust [63].

The NEMA Standard 250-2003 for Enclosures for Electrical Equipment does test for environmental conditions such as corrosion, rust, icing, oil, and coolants. IEC Standard 60529 [64] also provides a system for specifying the enclosures of electrical equipment, using IP code on the basis of the degree of protection provided by the enclosure. However, it does not specify degrees of protection against mechanical damage of equipment, risk of explosions, or conditions such as moisture (produced, e.g., by condensation), corrosive vapors, fungus, or vermin. For this reason, and because the test and evaluations for other characteristics are not identical, the IEC Enclosure Classification Designations cannot be exactly equated with the enclosure Type numbers in NEMA Standard. In 2004 IEC Standard was adopted by ANSI and a comparison of the two rating systems has been provided [64,65].

The various materials used for building enclosures are listed in [Table 5.8](#).

TABLE 5.6
Comparison of Specific Applications of Enclosures for Indoor Nonhazardous Locations

Provides a Degree of Protection Against the Following Conditions	Type of Enclosure									
	1 ^a	2 ^a	4	4X	5	6	6P	12	12K	13
Access to hazardous parts	X	X	X	X	X	X	X	X	X	X
Ingress of solid foreign objects (falling dirt)	X	X	X	X	X	X	X	X	X	X
Ingress of water (Dripping and light splashing)	...	X	X	X	X	X	X	X	X	X
Ingress of solid foreign objects (Circulating dust, lint, fibers, and flyings ^b)	...	...	X	X	...	X	X	X	X	X
Ingress of solid foreign objects (Settling airborne dust, lint, fibers, and flyings ^b)	...	...	X	X	X	X	X	X	X	X
Ingress of water (Hosedown and splashing water)	...	...	X	X	...	X	X	...	...	...
Oil and coolant seepage	...	...	...	..	...	...	...	X	X	X
Oil or coolant spraying and splashing	...	...	...	...	...	...	...	...	...	X
Corrosive agents	...	...	...	X	...	...	X	...	...	...
Ingress of water (Occasional temporary submersion)	...	...	...	...	...	X	X	...	...	...
Ingress of water (Occasional prolonged submersion)	...	...	...	...	...	...	X	...	...	...

Source: NEMA Standards Publication 250-2003. *Enclosures for Electrical Equipment (1000 Volts Maximum)*, Online. Available: <http://www.global.ihs.com>. With permission.

^a These enclosures may be ventilated.
^b These fibers and flyings are nonhazardous materials and are not considered Class III type ignitable fibers or combustible flyings. For Class III type ignitable fibers or combustible flyings see the National Electrical Code, Article 500.

5.7.2 POWDER COATING/PAINT USED FOR ENCLOSURES

Enclosures made of aluminum and stainless steel usually do not require additional protection. The choice of coating for steel depends on what kind of environmental chemicals the equipment might be exposed [62]. To protect steel enclosures from corrosive solvents, fumes and gases, various powder coatings (polyester, epoxy), polyurethane paint, or galvanized steel is recommended.

5.7.2.1 Criteria for Paint Type Selection

Various criteria and their order of importance need to be established when selecting the best coating for enclosures, which basically performs two functions: protection and decoration. It is important to know the exposure conditions, which are subdivided into three categories:

- *Severe* conditions including total immersion in chemicals or salt water, coastal situations, areas of high industrial pollution, and areas close to chemical processing plants.

TABLE 5.7
Comparison of Specific Applications of Enclosures for Outdoor Nonhazardous Locations

Enclosure Provides a Degree of Protection Against the Following Conditions	Type of Enclosure									
	3	3X	3R ^a	3RX ^a	3S	3SX	4	4X	6	6P
Access to hazardous parts	X	X	X	X	X	X	X	X	X	X
Ingress of water (Rain, snow, and sleet ^b)	X	X	X	X	X	X	X	X	X	X
Sleet ^c	...	...	...	...	X	X	...	...	...	...
Ingress of solid foreign objects (Windblown dust, lint, fibers, and flyings)	X	X	...	...	X	X	X	X	X	X
Ingress of water (Hosedown)	...	...	...	...	...	...	X	X	X	X
Corrosive agents	...	X	...	X	...	X	...	X	...	X
Ingress of water (Occasional temporary submersion)	...	...	...	...	...	...	...	...	X	X
Ingress of water (Occasional prolonged submersion)	...	...	...	...	...	...	...	...	...	X

Source: NEMA Standards Publication 250-2003. *Enclosures for Electrical Equipment (1000 Volts Maximum)*, Online. Available: <http://www.global.ihs.com>. With permission.

^a These enclosures may be ventilated.
^b External operating mechanisms are not required to be operable when the enclosure is ice covered.
^c External operating mechanisms are operable when the enclosure is ice covered.

- *Moderate* conditions are found in outdoor exposure to heavy rainfall and continuous humidity in light industrial and urban conditions, rural areas and inland areas more than two miles from industrial districts, and coastal areas.
- *Mild* conditions are experienced in interiors subject to condensation, as well as interiors where there is a source of pollution. Very mild conditions are found in warm, dry interiors not subject to condensation or pollution.

Additionally, the coating choice also depends on whether or not the enclosure will be exposed to bright sunlight and high temperatures. According to the application and service conditions, the paint and powder coatings usually recommended are presented in [Table 5.9](#).

5.7.2.2 Techniques of Applying a Powder Coating/Paint to Metal Panels

To improve corrosion resistance of a powder coating, primer coating is usually used. For example, either zinc phosphate (for outdoor application) or iron phosphate (for indoor applications) is used as a primer under polyester powder coating to improve the corrosion resistance of the paint.

Zinc-rich primers are used to protect steel surfaces from corrosion. Unlike regular paints or epoxies, which resist corrosion by forming an impermeable barrier between the metal and atmospheric moisture, zinc-rich primers provide corrosion

TABLE 5.8
Materials Used for Enclosures and Applications

Material	Application
Hot Rolled Pickled and Oiled Steel (ASTM A569)	General indoor and outdoor use after a suitable finish has been applied to protect against corrosion.
Cold Rolled Steel (ASTM A366)	General indoor and outdoor use after a suitable finish has been applied to protect against corrosion.
Galvanized Steel (ASTM A653)	Indoor or outdoor use in neutral pH. Resists oil, gas, glycerine, dichromates, borates, and silicates. The most frequent application is outdoor including seacoast atmospheres. Additional finishes may be applied to improve corrosion resistance.
18–8 Stainless Steel (Type 302–304)	Indoor and outdoor use. Ideally suited for use in food processing areas, dairies, breweries, or any wet area. Also works well in areas where caustic elements or alkalies are present.
316 or 316 L Stainless Steel	Indoor or outdoor use in almost any environment. Provides improved resistance to salt, some acids, and high temperature. Resistance to sulfates and chlorine is less than Type 304. These stainless steels are the most corrosion resistant metal materials for enclosures. A superior material choice for marine environments.
5052 Aluminum	Indoor or outdoor use, particularly in marine environments. Also an excellent choice for enclosures exposed to solvents, petrochemicals, some acids, most sulfates and nitrates.
Monel	Frequently specified for marine and chemical plant applications. Monel hardware is used on many of nonmetallic enclosures. High cost.
Galvannealed Steel (ASTM A653)	Indoor or outdoor use where a painted finish is important. Used in the automotive industry. Corrosion resistant, excellent paintability, easy weldability. The combined paint/galvannealed coating is resistant to peeling and/or blistering with properly selected paints and primers.

Source: Modified from Enclosure Metal Specifications Technical Data, Online. Available: <http://www.hubbell-wiegmann.com/catalog/sectionL.pdf>.

protection by electrical means. The zinc and steel form a tiny electrical cell that protects the steel at the expense of the zinc, forming the so-called “sacrificial” layer. A zinc primer under a top coat of powder coating provides a backup or secondary method of protecting the steel from corrosion.

After applying primer, either through automatic or manual electrostatic application, a dry coating powder is charged as it passes through an ionized field and is attracted by the grounded part. After application, the paint is cured; this thermal curing causes cross linking that produces a hard and durable finish with above average physical properties.

There are a number of different powder coating specifications that vary depending on the manufacturer of electrical equipment and the type of equipment. For example, pad-mounted equipment is designed for mounting on a concrete pad with

TABLE 5.9
Types and Properties of Different Powder Coatings and Paints for Enclosures

Coating Type	Properties	Max Service Temperature	Use	Applications
Polyester Urethane	Good adhesion, flexibility, corrosion and weather resistance.	120°C/250°F	Indoor or outdoor	Mild steel, aluminum, or stainless steel. UL approved.
Polyester TGIC	Good adhesion and flexibility, corrosion and weather resistance.	80°C/180°F	Indoor or outdoor	Mild steel, aluminum, or stainless steel. UL approved
Epoxy	Good adhesion and flexibility, corrosion and weather resistance	150°C/300°F	Indoor	Mild steel, aluminum, or stainless steel
Hybrids (blend of polyester and epoxy resins)	Excellent mechanical strength and corrosion resistance, chemically resistant to many acids, oils, and solvents		Indoor	Mild steel, aluminum, or stainless steel
Polyurethane paint	Excellent corrosion resistance and good outdoor performance	80°C/180°F	Indoor or outdoor	Meets UL Type 4 ^a requirements
Epoxy enamel coating	Excellent protection against corrosion and chemicals	120°C/250°F	Indoor	Meets UL Type 4 ^a requirements
Polyamide Epoxy	Excellent protection against corrosion and chemicals	95°C/200°F	Indoor or outdoor	Meets UL Type 4 ^a requirements

^a NEMA Type 4 Enclosures constructed for either indoor or outdoor use to provide a degree of protection to personnel against incidental contact with the equipment enclosed within; to provide a degree of protection against falling dirt, rain, sleet, snow, windblown dust, splashing and hose-directed water; and that will not be damaged by the formation of ice on the exterior of the enclosure (see [Tables 5.5](#) and [5.6](#)).

underground connecting cables, with the enclosures usually made of galvanized, galvannealed, or stainless steel. To provide superior corrosion resistance of these enclosures primers are usually used, such as zinc-rich epoxy, high-solid epoxy, and electrodeposited epoxy. Also two, and not one, finish coats are applied. Some examples of OEM coating specifications are given in [Table 5.10](#) for outdoor pad-mounted equipment with the enclosures made of different types of steel.

5.7.3 DEFECTS AND FAILURES OF POWDER COATINGS AND PAINTS

Signs of paint and coating failure may differ depending on the type of coating and especially on the type of environment the coating is exposed to. The coating may be metallic as in galvanized and galvannealed steel. The failure of the metallic coating may be defined as an excessive corrosion of the coating and steel under the coating. The failure may be caused by the inappropriate metallic coating type and its

TABLE 5.10
Powder Coating Specifications for Pad-Mounted Equipment

Equipment Type	Base Steel	Primer Type, Thickness	Paint, Thickness	Salt Fog Test, h
MV 3-phase capacitor bank	Hot-roll 12 gauge	Zinc rich epoxy coating, 50 μm (2 mils) ^a	Polyester TGIC, 50 μm (2 mils)	N/A
MV capacitor bank	Hot-roll 12 gauge, stainless steel optional	Primer, 25 μm (1 mil)	Two finish coats, 50 μm (2 mils)	N/A
MV gear PMH	Hot-roll 12 gauge, stainless steel optional	N/A	Super Durabake II finish ^c	1500 ^d
MV switchgear	A-60 galvaneal steel	N/A	N/A	4000
MV capacitor bank	11-gauge A-60 galvaneal steel	N/A	N/A	4000
Equipment substation transformers	N/A	Electro-deposited epoxy ^b	Two-component urethane paint, 50–100 μm (2–4 mils)	N/A

^a Pre-paint procedure—Iron Phosphate conversion, plus polymeric coating.

^b Pre-paint procedure—Iron Phosphate conversion coating.

^c Durabake—spray polyurethane coat, applied to firearms, marine surfaces, and so on.

^d 3000 h on stainless steel.

thickness, the type of pre-treatment and its compatibility with the metallic coating, the type of primer and its thickness.

The coating may be either organic or inorganic, thermoset or thermoplastic material in powder coating or paint. Different mechanical defects (blisters, pinholes, tearing) could be found on the powder coating or paint, such as pinholes, which appear as small spots without any coating [66]. Blisters in the coating are caused by entrapped air, gases, or moisture during the coating process. Pinhole in a powder coating is caused by entrapped moisture from the pretreatment which evaporate during the curing process. Another defect—cissing or nonuniform wetting of the surfaces—appears as areas or spots without any coating.

The coating may also have too low thickness, which results in poor surface finish. If the coating has too high thickness the profile surface may get an orange peel appearance. A rough surface finish may be caused by coarse powder particles which have been cured before melting and the formation of a smooth coating layer. All these defects in coating may result in its premature failure.

If corrosion of painted steel is observed, the failure may be explained by the wrongly chosen type of paint and its thickness, or defects in the paint caused by improper painting techniques. The specific environmental conditions must also be taken into account. An example of a failed powder coating which resulted in corrosion of a steel enclosure is shown in [Figure 5.10](#).

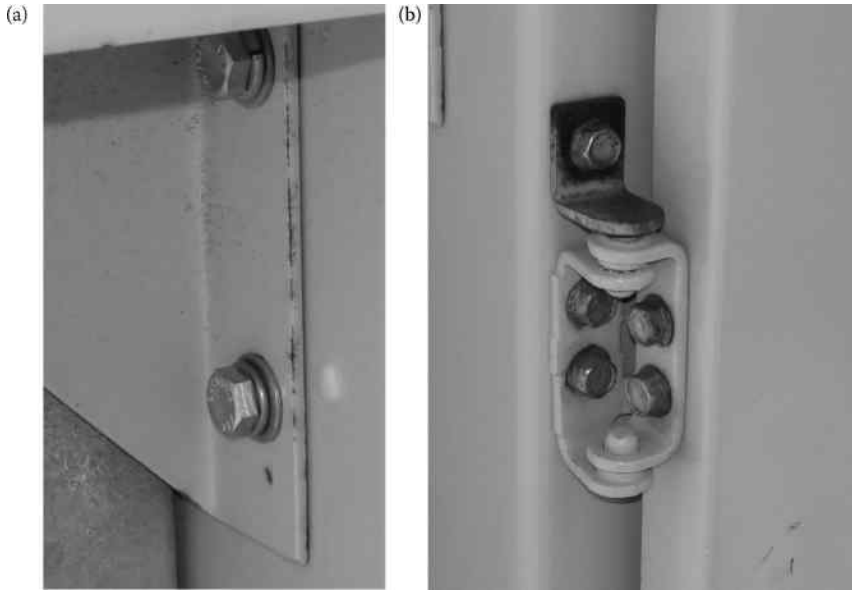


FIGURE 5.10 (See color insert.) Corrosion of steel panels (a) and brackets and bolts (b) of CB enclosure caused by coating failure.

ASTM Standard D1654 [67] defines a means of evaluating and comparing the basic corrosion performance of paint including the substrate, pretreatment, or coating system, or combinations thereof, after exposure to corrosive environments. The test method covers the treatment of previously painted or coated specimens for accelerated and atmospheric exposure tests and their subsequent evaluation with respect to corrosion, blistering associated with corrosion, loss of adhesion at a scribe mark, or other film failures. Salt Spray (SS) testing is usually used for determining corrosion protection properties of the coating [68].

5.7.4 HV RTV COATING

In 1970 Dow Corning was approached by major U.S. utilities to develop and supply a permanent and longer-term solution to protect HV glass and porcelain insulators from pollution that causes severe flashovers, resulting in power outages and losses together with reduced reliability of power lines. The ideal coating would be the one that cannot be easily contaminated. The concept of using an RTV (Room Temperature Vulcanization Silicone) as a permanent coating was developed by Dow Corning in the form of high-voltage insulator coatings (HVIC) [69].

RTV coating is used to protect outdoor porcelain and glass HV insulators from environmental contamination, which has been a long-term source of severe flashover problems that have resulted in power outages and losses together with reduced reliability. HVIC was extensively tested by major U.S. utilities between 1974 and 1984.

Global applications of RTV coating included the Americas, Europe, and Asia and with voltages ranging from 11 to 500 kV DC.

IEEE developed a guide [70] that summarized various important aspects that are needed for satisfactory long-term performance of HVIC. Various possible application scenarios, maintenance issues on coated insulators, factors affecting long-term performance, the question of aging, laboratory accelerated tests, and functional outdoor evaluation are described in this guide.

RTV coating when applied to the insulator modifies the surface properties of the glass or porcelain insulator by creating a hydrophobic material surface that interrupts the flashover mechanism at an early stage. RTV prevents the formation of a conductive water film, thereby limiting and successfully managing surface leakage currents. Arc track resistant additives are used to control surface temperature and avoid surface damage under high electrical activity.

RTV coating has been mostly applied as a retrofit solution to existing substation insulators which are in highly polluted environments. However, lately, a number of new OHTL have also been RTV-coated prior to installation; these have been mostly in the Middle and Far East.

5.7.4.1 Aging of RTV Insulation

Since its introduction in the eighties of the last century, RTV coatings have been modified and manufactured by many companies, and have also been tested in the field and the laboratory to determine the moisture absorption properties of the coating and aging factors [71–73]. It was found [72] that RTV silicone coatings applied to the porcelain outdoor insulators darkened in color and the cracks had developed in the RTV coating on all energized insulators. The cracks extended to the surface of the porcelain insulator after the coating had been subjected to 345 kV system voltage and exposure to weather conditions for a period of 7 years. Most of the original mechanical strength and elasticity of the RTV silicone coatings had been lost. It was suggested the aging process was accelerated by acid rain, which is not rare along coast lines.

5.7.4.2 The Role of Fillers in RTV Coatings

The factors having a significant influence on the aging performance of RTV coatings include the composition of the polymer and inorganic material (filler), which is an essential part of the coating affecting its dielectric and hydrophobic properties [74]. Inorganic fillers in silicone rubber dielectrics enhance the properties of thermal conductivity, relative permittivity, and electrical conductivity, making them useful in outdoor HV insulation applications. The addition of alumina trihydrate (ATH) or silica (SiO_2) fillers to silicone polymers produces binary composites with enhanced thermal conductivity.

The filler type, particle size, shape, and concentration also play an important role in improving the coating performance. The enhanced relative permittivity of silicone dielectrics is obtained through additional fillers, such as barium titanate powder, which can be further increased with the addition of aluminum powder, also improving the dielectric properties of RTV. The use of antimony-doped tin oxide filler binary composites when the coating is applied to outdoor bushings greatly enhances the pollution performance of the coating.

The way the filler is bonded to the polymer matrix and the existence of other fillers can improve the performance of RTVs in severe ambient conditions. The study [75] indicated that the initial loss of hydrophobicity can be correlated to the surface discharges that develop on the material surface due to the droplets formed. The hydrophobicity loss was observed for silica-filled coating, which also have the lowest value of heat conductivity. Lower levels of surface activity and material deterioration were observed for the ATH-filled coatings in comparison to the SiO_2 -filled ones.

5.8 ELECTRICAL INSULATION STANDARDS AND GLOSSARY

5.8.1 NATIONAL AND INTERNATIONAL STANDARDS AND REGULATIONS ON INSULATION

The following national and international standards specify the requirements for various insulation materials and types of insulators, and they are only a partial list of the standards on insulation. Other Standards describe the procedures for testing insulation.

For example, in ANSI C29.1-1988 (R2002), “American National Standard for Electrical Power Insulators—Test Methods,” procedures for conducting tests to determine the characteristics of the insulators used on electric power systems are given.

European Standard IEC 60156 Ed. 2.0 b:1995, “Insulating liquids—Determination of the Breakdown Voltage at Power Frequency (PF)—Test Method,” describes an empirical test procedure intended to indicate the presence of contaminants such as water and solid suspended matter, and the advisability of carrying out drying and filtration treatment. Standardized testing procedures and equipment are essential for the unambiguous interpretation of test results.

5.8.1.1 North American Standards for Solid Insulation

ANSI/IEEE Standard C29.1-1988 (R2002), “American National Standard for Electrical Power Insulators—Test Methods”

ANSI/IEEE Standard C29.2-1992 (R1999), “Wet-Process Porcelain and Toughened Glass Suspension Type”

ANSI/IEEE Standard C29.5-1984 (R2002), “Wet-Process Porcelain Insulators—Low and Medium Voltage Types

ANSI/IEEE Standard C29.7-1996, “Wet Process Porcelain Insulators, High-Voltage Line-Post Type”

ANSI/IEEE Standard C29.8-1985, “Wet Process Porcelain Insulators, Apparatus, Cap and Pin Type”

ANSI/IEEE Standard C29.9-1983, “Wet Process Porcelain Insulators, Apparatus, Post-Type”

ANSI/IEEE Standard C29.10-1989 (R2002), “Wet Process Porcelain Insulators, Indoor Apparatus Type”

ANSI/IEEE Standard C29.11-1989 (R1996), “Composite Suspension Insulators for Overhead Transmission Lines, Tests”

- ANSI/IEEE Standard C29.12-1997 (R2002), “Insulators Composite, Suspension Type”
- ANSI/IEEE Standard C29.13-2000, “Insulators Composite, Distribution Dead End Type”
- ANSI/IEEE Standard C29.17-2002, “Insulators Composite, Line Post Type”
- ANSI/IEEE Standard C29.18-2003, “Insulators Composite, Distribution Line Post Type”
- ANSI/IEEE Standard C57.19.00-2004, “General Requirements and Test Procedure for Power Apparatus Bushings”
- ANSI/IEEE Standard 1572 (2004), “Guide for Application of Composite Line Post Insulators”
- ANSI/IEEE Standard 95-2002, “IEEE Recommended Practice for Insulation Testing of AC Electric Machinery (2300 V and Above) with High Direct Voltage”
- ANSI/IEEE Standard 1313.2-1999, “IEEE Guide for Application of Insulation Coordination”
- ANSI/IEEE Standard C57.12.00-2010, “General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers”
- IEEE 400-2001, “IEEE Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems”
- IEEE 1434-2000, “IEEE Trial-Use Guide to the Measurement of Partial Discharges in Rotating Machinery”.
- NEMA Standards Publication No. HV 2-1991 (R1996, R2002), “Application Guide for Ceramic Suspension Insulators”
- UL 1446, “Standard for Safety of Systems of Insulating Materials— General”
- CAN411.1-10, “AC Suspension Insulators”
- CAN411.4, “Composite Insulators for A.C. Overhead Lines”
- CAN411.6, “Line Post Composite Insulators for Overhead Distribution Lines”
- CAN411.7, “Composite Insulator for Guy Wires”

5.8.1.2 International Standards for Solid Insulation

- European Standard EN 50151, “Fixed installations—Electric traction— Special Requirements for Composite Insulators”
- IEC 120 third edition (1984), “Dimensions of Ball and Socket Couplings of String Insulator Units”
- IEC 273 third edition (1990-02), “Characteristics of Indoor and Outdoor Post Insulators for Systems with Nominal Voltages Greater than 1000 V”
- IEC 305 fourth edition (1995-12), “Insulators for Overhead Lines with A Nominal Voltage Above 1000 V. Ceramic or Glass Insulator Units for A.C. Systems. Characteristics of Insulator Units of the Cap and Pin Type”
- IEC 720 first edition (1981), “Characteristics of Line Post Insulators”
- IEC 60085, “Electrical Insulation—Thermal Evaluation and Designation”
- IEC 60137 fifth edition (2003-08), “Insulated Bushings for Alternating Voltages Above 1000 V”
- IEC 60216-1 ed5.0 (2001-07), “Electrical Insulating Materials—Properties of Thermal Endurance—Part 1: Ageing Procedures and Evaluation of Test Results”

- IEC 60216-2 ed4.0 (2005-08), "Electrical Insulating Materials—Thermal Endurance Properties—Part 2: Determination of Thermal Endurance Properties of Electrical Insulating Materials—Choice of Test Criteria"
- IEC 60270:2000/BS EN 60270:2001, "High-Voltage Test Techniques—Partial Discharge Measurements"
- IEC 60433 third edition (1998-08), "Insulators for Overhead Lines with A Nominal Voltage Above 1000 V. Ceramic Insulators for AC Systems. Characteristics of Insulator Units of the Long Rod Type"
- IEC 60471 second edition (1977-01), "Dimensions of Clevis and Tongue Couplings of String Insulator Units"
- IEC 60660 second edition (1999-10), "Tests on Indoor Post Insulators of Organic Material for Systems with Nominal Voltages Greater than 1000 V Up to But not Including 300 kV"
- IEC 60672-1, IEC 60672-2 and IEC 60672-3, "Specification for Ceramic and Glass Insulating Materials"
- Part 1 second edition (1995-07), "Definitions and Classification"
- Part 2 second edition (1999-12), "Methods of Tests"
- Part 3 second edition (1997-10), "Specifications for Individual Materials"
- IEC 60815, "Selection and Dimensioning of High-Voltage Insulators Intended for Use in Polluted Conditions"
- IEC 61109 second edition (2008-05), "Composite Suspension and Tension Insulators for AC Systems with A Nominal Voltage Greater than 1000 V. Definitions, Test Methods and Acceptance Criteria"
- IEC 61466-1 and IEC 61466-2, "Composite String Insulator Units for Overhead Lines with A Nominal Voltage Greater than 1000 V"
- Part 1 first edition (1997-02), "Standard Strength Classes and End Fittings"
- Part 2 edition 1.1 (2002-02), "Dimensional and Electrical Characteristics"
- IEC 61857, "Electrical Insulation Systems—Procedures for Thermal Evaluation—Part 1: General Requirements—Low Voltage"
- IEC 61858, "Electrical Insulation Systems—Thermal Evaluation of Modification to an Established Wire-Wound EIS"
- IEC 61952 second edition (2008-05), "Insulators for Overhead Lines. Composite Line Post Insulators for Alternative Current with A Nominal Voltage Greater than 1000 V—Definitions, Test Methods and Acceptance Criteria"
- IEC TS 62073 Technical Specification first edition (2003-06), "Guidance on the Measurement of Wettability of Insulator Surfaces"
- IEC 62217 second edition (2005-10), "Polymeric Insulators for Indoor and Outdoor Use with A Nominal Voltage Greater than 1000 V—General Definitions, Test Methods and Acceptance Criteria"
- IEC 62231 Ed. 1.0, "Composite Station Post Insulators for Substations with A.C. Voltages Greater than 1000 V Up to 245 kV—Definitions, Test Methods and Acceptance Criteria"
- DIN VDE0302, "German Standard for Testing and Requirements of Electrical Insulating Materials in General"
- DIN VDE0441, Part 2 and Part 2, "German Standard for Testing & Material Requirements of Composite Insulators."

5.8.1.3 National and International Standards for Transformer Oil

- ANSI/IEEE Standard C57.12.00-1993, “General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers”
- ANSI/IEEE Standard C57.104-1991, “IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers”
- ANSI/IEEE Standard C57.106.2002, “IEEE Guide to Acceptance and Maintenance of Insulation Oil in Equipment”
- ANSI/IEEE Standard PC57.127/D10.0, 2007, “Draft Guide for the Detection and Location of Acoustic Emissions from Partial Discharges in Oil-Immersed Power Transformers and Reactors
- ASTM D877-02(2007), “Standard Test Method for Dielectric Breakdown Voltage of Insulating Liquids Using Disk Electrodes”
- ASTM D1533-00(2005), “Standard Test Method for Water in Insulating Liquids by Coulometric Karl Fischer Titration”
- ASTM D1816-04, “Standard Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Using VDE Electrodes”
- ASTM Standard D3612-02(2009)—Standard Test Method for Analysis of Gases Dissolved in Electrical Insulating Oil by Gas Chromatography
- IEC 60156 Ed. 2.0 b: 1995, “Insulating liquids—Determination of the breakdown voltage at PF—Test method”
- IEC 60296, “Mineral Insulating oils for transformers & switchgear”
- AS 1767.1—1999, “Australian Standard for insulating liquids. Part 1: Specification for unused mineral insulating oils for transformers and switchgear.”

5.8.1.4 National Standards for Paints and Coatings for Steel

- ASTM D610, “Standard Test Method for Evaluating Degree of Rusting on Painted Steel Surfaces”
- ASTM D714, “Standard Test Method for Evaluating Degree of Blistering of Paints”
- ASTM D1654, “Standard Test Method for Evaluation of Painted or Coated Specimens Subjected to Corrosive Environments
- ASTM D4228, “Standard Practice for Qualification of Coating Applicators for Application of Coatings to Steel Surfaces”
- IEEE Standard 1523-2002, “Guide for the Application, Maintenance, and Evaluation of Room Temperature Vulcanizing (RTV) Silicone Rubber Coatings for Outdoor Ceramic Insulators.”

5.8.2 INSULATION GLOSSARY

5.8.2.1 Solid Insulation Glossary

C-D

Carbon black: A black pigment. It imparts useful ultraviolet protective properties, and hence is frequently suspended into plastic and elastomeric compounds intended for outside weather exposure.

Chlorinated polyethylene (CPE): A synthetic rubber jacketing compound.

Chlorosulfonated polyethylene (CSPE): A synthetic rubber jacketing compound manufactured by Du Pont under trade name of Hypalon.

Chlorinated polyethylene (CPE): Jacketing material.

Dielectric breakdown: The voltage at which a dielectric material is punctured; which is divisible by thickness to give dielectric strength.

Dielectric constant: A physical property of an insulating material which is the ratio of the parallel capacitance (C) of a given configuration of electrodes with the material as the dielectric, to the capacitance of the same electrode configuration with vacuum as the dielectric.

Dielectric strength: The voltage which an insulating material can withstand before breakdown occurs, usually expressed as a voltage gradient (such as volts per mil).

Dielectric tests: (1) Tests which consist of the application of a voltage higher than the rated voltage for a specified time for the purpose of determining the adequacy against breakdown of insulating materials and spacings under normal conditions. (2) The testing of insulating materials by the application of constantly increasing voltage until failure occurs.

Double insulation: Insulation comprising both basic insulation and supplementary insulation.

Durabake: Spray polyurethane coat, applied to firearms, marine surfaces, and so on.

E

EIS: Electrical insulation systems.

EIM: Electrical insulating materials.

Epoxy: Also known as *polyepoxide*, epoxy is a thermosetting polymer formed from the reaction of an epoxide “resin” with a polyamine “hardener.” Epoxy has a wide range of applications, including fiber-reinforced plastic materials and general-purpose adhesives. Two part epoxy coatings were developed for heavy-duty service on metal substrates; they use less energy than heat-cured powder coatings.

ETFE: Modified Ethylene Tetrafluoroethylene compound used for insulation and jackets.

Ethylene propylene rubber (EPR): Synthetic rubber insulation based upon ethylene propylene hydrocarbon.

F-H

Fluorinated ethylene propylene (FEP): Insulation and jacket compound having specific electrical characteristics.

Functional insulation: Insulation needed for correct operation of the equipment.

Fibrous filler: A material used to fill interstices in cables made from fibers, such as jute, polypropylene, cotton, glass, and so on.

Filler: Any material used in multiconductor cables to occupy interstices between insulated conductors or form a core into a desired shape (usually circular).

Also, any substance, often inert, added to a plastic or elastomer to improve its properties or decrease its cost.

Flame resistance: The ability of a burning material to extinguish its own flame, once its flame-initiating heat source is removed.

Flame retardance: Ability of a material to prevent the spread of combustion by a low rate of travel so the flame will not be conveyed.

Hygroscopic: Attracting or absorbing moisture from the ambient atmosphere.

Hypalon: Du Pont trademark for chlorosulfonated polyethylene (CSPE) synthetic rubber.

I-J

Insulation level-100%: Cable for use on grounded systems or where the system is provided with relay protection such that grounds faults will be cleared as rapidly as possible but in any case within 1 min.

Insulation level-133%: Cable for use on ungrounded or grounded systems or where the faulted section will be de-energized in a time not exceeding 1 h.

Insulation resistance: The amount of leakage current that will flow through when a voltage is applied across a layer of insulation. It is determined by the voltage divided by the insulation resistance.

Jacket: A material covering over a wire insulation or an assembly of components, usually an extruded plastic or elastomer.

M-N-O

Metal-clad cable: NEC type designation for power and control cables enclosed in a smooth metallic sheath (Okoclad), welded and corrugated metallic sheath (C-L-X), or an interlocking tape armor (Loxarmor). (NEC Article 330.)

Medium-voltage cable: NEC designation for single and multiple conductor insulated cables rated 2001–35,000 V. (NEC Article 328.)

Migration: The loss of plasticizer from a plastic, usually due to heat or aging. It is undesirable since it will make the plastic hard and brittle. It is also called leaching.

Mining cable: A flame retardant cable especially constructed to withstand rough handling and exposure to moisture for underground use in the environment of a mine or tunnel, or surface use where it is exposed to sunlight and extremes of temperature.

Moisture absorption: The amount of water that an insulation or jacket, which is initially dry, will absorb under specified conditions. It is expressed as the percentage ratio of the absorbed water's weight to the weight of the jacket or insulation alone.

Neoprene: Trade name for polychloroprene, used for jacketing (see polychloroprene).

Nitrile rubber: A rubbery copolymer of butadiene and acrylonitrile. It is usually compounded and vulcanized.

Nordel: Du Pont trademark for EPDM synthetic rubber.

Oxygen bomb test: A test to determine the ability of conductors and insulations to withstand physical and electrical change when immersed in pure oxygen gas of a specified temperature and pressure for a specified time.

P

Plastic: Any solid material employing organic matter of a high molecular weight as a principal constituent, which can be shaped by heat and pressure during manufacturing or processing into a finished article.

Plasticizer: A substance incorporated into a material to increase its workability or flexibility.

Polychloroprene: Chemical name for neoprene A, a rubber-like compound used for jacketing where the wire and cable will be subjected to rough usage, moisture, oil, greases, solvents, and chemicals.

Polyester: A resin generally used as a thin film in tape form. Depending on the chemical structure, polyester can be a thermoplastic or thermoset; however, the most common polyesters are thermoplastics.

Polyester, thermoset: A family of resins formed by the reaction of a dibasic organic acid and a polyhydric alcohol. Notable for fast cure, the unusual variety of processing methods available, and its combination of excellent physical, electrical, heat, and chemical properties at reasonable cost. Particularly compatible with reinforcing glass fibers.

Polyethylene: A thermoplastic material composed of polymers of ethylene.

Polymer: A material formed by the chemical combination of monomers having either the same or different chemical compositions.

Polypropylene: A thermoplastic polymer of propylene.

Polyvinyl chloride (PVC): A thermoplastic material composed of polymers of vinyl chloride, which may be rigid or elastomeric, depending on specific formulation. *PVC* is used as insulating and jacketing material which is usually flame-retardant and resistant to many chemicals.

Power-limited circuit: A circuit that is either inherently limited requiring no over-current protection or limited by a combination of a power source and over-current protection.

Primer: A preparatory coating put on materials before painting. Priming ensures better adhesion of paint to the surface, increases paint durability, and provides additional protection for the material being painted.

R

Reinforced insulation: A single insulation system which provides a degree of protection against electric shock equivalent to double insulation under the conditions specified in IRC 60950 Standard.

RTV: Room temperature vulcanization silicone (RTV).

Rubber: A material that is capable of recovering from large deformations quickly and forcibly and that can be, or already is, modified to a state in which it is essentially insoluble (but can swell) in boiling solvent.

S

Salt spray (fog) test: Standard test method for evaluation of painted or coated specimens subjected to corrosive environments (ASTM Standard D1654-08). A salt spray test is an accelerated corrosion test that produces a corrosive

attack to the coated samples in order to predict its suitability for use as a protective finish.

Screen: A semiconducting nonmetallic layer used under and over the insulation of power cables rated over 2 kV to reduce electrical stresses and corona.

Secondary insulation: Any extremely high resistance material which is placed over the primary insulation to protect it from abrasion.

Semiconducting: An extruded layer or tape of such a resistance that, when applied between two elements of a cable, the adjacent surfaces of the two elements will maintain almost the same potential.

Specific dielectric strength: The dielectric strength per millimeter of thickness of an insulating material.

Specific inductance capacitance: That property of a dielectric material which determines how much electrostatic energy can be stored per unit volume when unit voltage is applied.

Stabilizer: Any ingredient added to plastics to preserve their physical and chemical properties.

Supplementary insulation: Independent insulation applied in addition to basic insulation in order to ensure protection against electric shock in the event of failure of the basic insulation.

T

Tear strength: The force required to initiate or continue a rip in a jacket or other insulation under specified conditions.

Temperature rating: The maximum temperature at which a given insulation or jacket may be safely maintained during continuous use, without incurring any thermally induced deterioration.

Thermocouple cable: A cable consisting of two dissimilar metals or alloys that, when electrically joined at one end, can be used to measure the temperature. These cables have no voltage rating.

Thermoplastic: A plastic that can be formed or melted repeatedly when heated enough. The change with temperature is physical rather than chemical. Some examples are nylon, polycarbonate, and polyethylene.

Thermoset: A plastic that undergoes a nonreversible chemical reaction when it is cured. Subsequent heating will not melt it. Examples are polyester, phenolic, melamine, epoxy, and silicone.

Thermoplastic polyolefin (TPPO): A thermoplastic jacket material with low smoke characteristics and free of halogens.

TPR: A trade name of Uniroyal Inc. for their thermoplastic rubber.

V-W-X

Vulcanization: An irreversible process during which a rubber compound through a change in its chemical structure (for example, cross-linking), becomes less plastic and more resistant to swelling by organic liquids and the elastic properties are conferred, improved, or extended over a greater range of temperature.

Water absorption: The ratio of the weight of water absorbed by a given material under specified conditions, to the weight of that material when dry. It is generally expressed as a percentage. Materials such as electrical insulation that absorbs little or no water will also be more dimensionally stable and have a smaller reduction of electrical properties when wet.

XLPE: Cross-linked polyethylene, an insulating compound.

XLPO: Cross-linked polyolefin, a thermoset jacket material with low smoke characteristics and free of halogens.

5.8.2.2 Insulating Oil Glossary

D-F

Degasification: Degasification removes harmful gases and water from the oil. This is an essential aspect of transformer maintenance since water decreases the dielectric strength of the oil, and dissolved gases cause arcing and corrosion, resulting in overheated connections. The amount of water held in suspension changes in relation to the temperature of the oil. Degasification is routinely performed in conjunction with all other oil reclamation services.

Dissipation factor: This test measures the dielectric losses in insulating oils due to heat dissipation in an electric field. High values indicate the presence of contaminants, oxidation products, and metal particles.

Fuller's earth systems: Fuller's earth removes both acid and particulates from the oil, including sludge and other contaminants. Sludging is a direct result of high acid content, and over time, sludge can harden over internal parts of the transformer, preventing the oil from circulating properly. Reclamation of oil with a high acid content requires Fuller's earth filtration and degasification. If reclamation is done in the early stages of acid build-up before sludging occurs, the oil will retain its properties longer under normal operating conditions.

H-I

Hot oil dryout: Once the used oil is removed from the transformer, the core and coil assembly are rinsed with clean oil to remove sludge or sediment caused by oxidation. The transformer is then partially filled with hot oil which is circulated to remove water and contaminants from the insulation. By cleaning the transformer in this manner, the cause of the oil contamination is addressed. Following this, the replacement oil will retain its properties longer under normal operating conditions.

Inhibitor: A number of organic chemical compounds are known to slow down the oxidation when added to lubricating or insulating oils. Such additives are known as antioxidants or oxidation inhibitors. Unfortunately, all known oxidation inhibitors become depleted with time. When all of the inhibitor has been used up, the oil starts to deteriorate again, and deterioration proceeds in the same way at the same (or greater) rate as in the uninhibited oil. The useful life of the oil is extended by the amount of time the inhibitor remains effective, before it becomes depleted.

Insulating oil (dielectric oil, transformer oil): Usually a highly refined mineral (petroleum-based) oil that is stable at high temperatures and has excellent electrical insulating properties. It is used in oil-filled transformers, some types of HV capacitors, fluorescent lamp ballasts, and some types of HV switches and CBs. Its functions are to insulate, suppress corona and arcing, and to serve as a coolant.

O

Oil circuit-breaker: A CB in which the contacts open and close in insulating oil.

Oil condition tests: A series of oil tests and analysis required to determine the condition of the insulating oil or as specified in the maintenance standards.

Oil leakage sump: A receptacle which is intended to receive the oil of a transformer or other oil-filled equipment in case of leakage.

Oil pass: The quantity of oil indicated on the transformer or tap-changer name plate which is circulated through the oil treatment plant.

Oil reclaiming: An oil treatment process which removes soluble and insoluble contaminants. Heated oil is vacuum dehydrated and then percolated through Fuller's earth and filtered. Additionally, the vacuum process will degas the oil.

Oil reconditioning: An oil treatment process where water and solids are removed by filtration, centrifuging, and vacuum dehydration. Additionally, the vacuum process will degas the oil and remove some of the more volatile acids.

Oil regeneration: A proprietary process which uses refining and blending techniques to produce insulating oil with essentially new oil characteristics.

Oil spray nozzle: A device that sprays oil into a transformer to degasify the oil while under vacuum and to uniformly distribute the hot oil over the core and windings.

Oil treatment: A term used in this standard to include the processes of reconditioning oil, reclaiming oil, and the de-sludging of transformers.

Oil water valve: A valve that automatically closes when an effluent with a quantity of oil flows through it. The oil may be sensed by a change in the specific gravity of the effluent or by an oil-in-water detector.

Oil-immersed-type transformer: A transformer of which the magnetic circuit and windings are immersed in oil [IEC 76-1].

Oily effluent: A mixture of oil and water.

Oily tighten: Tightening of oiled windings and major insulation after dry-out and oil impregnation.

P-R

Polychlorinated biphenyl: Polychlorinated biphenyls are very toxic and persistent in the environment. Polychlorinated biphenyls are widely used in electrical equipment, including transformers. Many transformers will still contain traces of Polychlorinated biphenyl-contaminated oil even after the oil has been changed several times.

PPM: Parts per million.

Retro filling: Involves removing the used oil from the transformer and replacing it with reclaimed oil.

T-V-W

TAN: Total Acid Number is the amount of potassium hydroxide (KOH) in milligrams that is needed to neutralize the acids in 1 g of oil. When transformer oils oxidize they begin to produce acids. These acids can adversely affect the insulation and inner components of the transformer. When significant amounts of acid are produced they will polymerize with each other or react with the metallic surfaces inside the transformer to form sludge. A low total acid number (<0.3 mg KOH/g oil) is necessary to maximize the life of the insulating system, and prevent sludge.

Vacuum filling: Vacuum filling is a critical step in ensuring that the new quality oil does not become contaminated during retro filling of the transformer.

Water content: Excessive water in the oil destroys the lubricant's ability to separate moving parts, allowing severe wear to occur. In addition, water increases corrosion rates and accelerates oil degradation. Degradation of oil results in loss of lubrication quality. The presence of water leads to premature plugging of filters, minimizing the effect of additives and supporting the growth of bacteria. A procedure that extracts water from an oil sample and determines the amount of water is called the Karl–Fisher method.

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6 Electrical Equipment Life Expectancy, Aging, and Failures

6.1 LIFE EXPECTANCY FOR DISTRIBUTION AND TRANSMISSION EQUIPMENT

6.1.1 ESTIMATION OF ELECTRICAL EQUIPMENT LIFETIME

A power system is composed of a number of components, such as lines, cables, transformers, circuit breakers (CBs), disconnectors, and so on. Every component in a power system has an inherent risk of failure. Multiple outside factors influence the possibility of component failure; for example, the current-loading of the component, damage by third parties (human or animal), and trees. Atmospheric conditions such as temperature, humidity, pollution, wind, rain, snow, ice, lightning, and solar effect may play a significant role in the component failure [1].

It is often assumed that the lifetime of installed electrical equipment is about 35–40 years [2].

However, when trying to estimate the life of equipment it is necessary to consider multiple factors such as the range of extreme operating conditions and environments, and the different levels of past maintenance.

For example, if the electrical equipment is located in a high-rise, modern office building, there is a good chance that the environment is very clean and temperatures are moderate. For the same equipment working in a paper mill or in a dust-filled environment, or in a hot and humid climate, the life expectancy cannot be the same [3]. Therefore, the typical life expectancy of the equipment may vary dramatically depending on the conditions of service and the environment [4].

Generally, the useful life of such power system components depends upon the level of care given to them and their duty cycles. For example, a CB on mainly switching duty can last 40–50 years. The majority of transformers at the utilities serve about 40 years if none of the catastrophic events such as lightening happen. On the other hand, on-load tap changers in HV transformers are prone to failure.

HV bushings are accounted for as one of the most significant single causes of failure in HV substations. The failure mechanisms tend to develop to a critical level at a mid-life point for the surrounding assets and such mechanisms generally result in a sudden and catastrophic failure of an explosive nature, thus significantly shortening the life span of HV substations [5].

Models used for the estimation of lifetime are based on stress tests (electrical, mechanical, and thermal) specified in the standards [6–8] and on the mathematical model of the mean time to first fail [9,10].

6.1.2 OVERLOADING AND ESTIMATED LIFE OF ELECTRICAL EQUIPMENT

Electric power components are typically assigned a capacity rating and an estimated life. The two parameters are related, and it is assumed that if the component does not experience overloading (an excess of its rating), it will stay in service in the stated useful life, whereas if it experiences excessive loading, its useful life will be decreased [11].

6.1.2.1 Circuit Breakers

A CB's function is to operate properly to interrupt fault currents. When a CB detects a fault, it acts to open its contacts, across which an electrical arc will develop. The arc either extinguishes itself, as in the case of an oil-filled breaker, or, as in the case of a gas-filled breaker, a blast of air or other gases (e.g., SF_6) is directed at the arc to extinguish it. Failure to interrupt the current within the required time will not only destroy the CB, but will probably also severely damage the equipment that it is designed to protect (transmission line, generator, etc.). Even if the fault currents are within the design parameters of the breaker, each breaker operation results in some mechanical erosion of the contacts and in the production of contaminants in the oil or gas insulation. The higher the fault current, the greater the degree to which the contacts are eroded and contaminants are produced and the sooner the breaker will fail or must be overhauled. Therefore, the higher the fault current level, the lesser the number of operations the CB is expected to perform before failure occurs [12,13].

6.1.2.2 Transformers

The negative effect on a transformer is mainly produced by the excess heat caused by overloading [14–16]. A transformer consists of an iron core around which are wrapped various coils of insulated wires. The core is positioned inside a tank filled with insulating oil, along with connectors, bushings, and various other small components.

Excess heat produced by overloading on a transformer causes degradation of the Kraft paper insulation around the wires, leading to internal failures of the coils. Another negative effect of the transformer overloading is in generating an excessive tank pressure and degradation of the insulating oil, either of which can cause catastrophic failures, even explosions, and leaking gaskets and seals. Overloading also generates harmonics, resulting in thermal cycling and mechanical vibration of the transformer, which cause physical damage by loosening electrical connections.

Any faults near the transformer, when they occur, will be greater than normal at overload, leading to an increased chance of damage to the transformer from fault currents. These include coil failures, bushing flashovers, blown gaskets and seals, connector failures, oil explosions and fires, and physical displacement of internal components due to electromechanical torques.

6.1.2.3 Conductors

The principal component of transmission and distribution lines is the conductor: a wire or bundle of wires made of aluminum, copper, or steel. If the overloading is severe enough and protection systems do not act properly to disconnect the line, only a few minutes or hours of overloading could lead to severe overheating. During these periods the conductor temperature will increase due to the heat generated by the resistive losses.

Too much high-temperature operation will cause annealing of the wires when they lose their elasticity and strength. The conductors will sag and violate clearance limits, which will require premature replacement with new conductors. Sometimes, splices or connectors in the line will overheat faster than the conductor itself, causing the connectors to fail, in which case the conductor may fall to the ground [17,18].

6.1.2.4 Underground Transmission

Transmission cables for underground circuits consist of copper conductors surrounded by paper or polyethylene (PE) insulation, and jacketed by layers of PVC or metal cladding. High-temperature operation will cause generally the same type of insulation degradation as in transformers. Exposure to high temperature will also result in connector failures and the leakage of fluid or gas. In underground transmission the conductors are not under tension; therefore annealing is not a concern.

6.1.3 TEMPERATURE AND ESTIMATED LIFE OF ELECTRICAL EQUIPMENT

In the previous section, it was explained that overloading conditions may lead to elevated temperature of all components. Elevated temperature is one of the most serious deteriorating factors for any component of transmission and distribution equipment and decreases the useful life of the electrical apparatus.

The majority of electrical distribution equipment are designed to operate properly and achieve normal life expectancy under ambient conditions if the temperature does not go below 0°C (32°F) and does not rise above 40°C (104°F) at RH levels from 0 to 99%.

Unless serious extremes of temperature are anticipated, heating requirements are limited to maintaining equipment surfaces above the dew point to avoid condensation and providing an acceptable work environment for service. It can be accomplished using electrical resistance heaters installed inside the enclosures, making it possible to install even medium-voltage (over 600 V and less than 72 kV) equipment in unheated spaces or outdoors.

The effect of exceeding the 40°C (104°F) ambient temperature varies with the type of equipment. For example, uninterruptible power supply (UPS) systems may shut down if the entering air temperature or internal temperature exceeds certain limits. Electronic devices such as relays and meters that are intended to be used in electrical switchgear may have ambient temperature specifications up to 70°C (158°F). In some cases, elevated temperatures require de-rating of the equipment.

Protective devices such as fuses and thermal-magnetic CBs, which detect overloads based on the heat produced by the current flowing through them, will trip at lower-than-rated currents in an elevated ambient. Less sophisticated equipment, such

as motors, switchgear bus, and transformers, will continue to operate properly in an elevated ambient, but will develop higher internal temperatures that can cause insulation deterioration and reduce life expectancy [19]. As a rule of thumb, the life of the insulation will decrease by 50% for every 10°C rise in temperature. It is evident that the higher the temperature, the shorter the life expectancy of the insulation [20,21].

Another cause of the temperature increase in an electrical machine is because of a rise in the electrical resistance of different components of the current-carrying path, which may be of many different origins [13]. The primary circuit resistance rise may be caused by the loosening of an electrical connection in the primary circuit as well as by a reduction of spring pressure within the fixed main contacts assembly of the interrupter. The resistance rise may be caused by chemical contamination, deposits of particles of dirt or grit, or oxidation (corrosion) of the surfaces of contact surfaces. Mechanical damage of the surfaces of main contacts may also lead to a significant electrical resistance rise of the current-carrying path. All these deteriorating processes in an electrical machine lead to the temperature rise (TR) shortening its useful life.

6.2 SIGNATURES OF AGING OF ELECTRICAL EQUIPMENT IN NUCLEAR, INDUSTRIAL, AND RESIDENTIAL ENVIRONMENTS

6.2.1 AGING FACTORS

During its useful life, electrical equipment experiences multiple stresses that affect its performance. These factors are electrical stresses (voltage, current, on–off cycling, overloading), electrostatic discharges (PD and corona), mechanical stresses (vibrations, shocks), extreme temperatures and temperature changes, humidity, corrosive environment, dust, and so on.

The effect of all these stresses gradually build up, leading to mechanical damage to the parts, corrosion of conductive parts, deterioration of insulation and eventually to failure of one or several components of the structure. The most significant aging is found on connectors when they are exposed to oxidation and contamination, high humidity or fretting corrosion. Cables may be mechanically damaged and chemically attacked. The insulation may degrade due to moisture, high temperature or radiation. Electromechanical components may get corroded, the contacts may be oxidized or contaminated, and the coils may burn out.

The longer the electrical equipment is subjected to all these stresses without due attention and maintenance, the shorter its useful life. However, aging of power equipment seldom leads to a sudden, catastrophic failure. Instead, the effect of all stress factors is cumulative; it is a slow but inevitable worsening each year.

To keep aging power equipment in good condition, to extend its useful life as much as possible, and to prevent a catastrophic failure, it is important to know how to timely identify the different modes, types, and outcomes of deterioration of electrical equipment.

Material fatigue and other losses of mechanical strength, losses of electrical properties like insulation strength or conductivity, increased friction and binding of moving mechanical parts—these are some electrical equipment deterioration modes.

It is essential to identify the causes of deterioration, either internal (overloading, lack of lubrication, mechanical stresses, overheating) or external (environmental factors such as contamination, dust, corrosive gases, humidity, etc.). Depending on the type of industry where the electrical equipment is serving, there may be significant differences in the causes and signs of deterioration.

6.2.2 AGING EQUIPMENT IN AN INDUSTRIAL ENVIRONMENT

6.2.2.1 Nuclear Facilities

The necessity of maintaining the electrical equipment in a nuclear power plant in safe and proper conditions is intensified by an elevated risk of any even minor failures at such facilities to the environment and the population. At a nuclear power plant, a special program called Aging Management Guidelines (AMGs) provides guidance on how to perform detailed evaluations of aging mechanisms and aging management strategies applicable to critical groups of equipment, among which are motor control centers (MCC), transformers, switchgear, cables, battery chargers, inverters, and UPS [22]. In Table 6.1, the aging factors for electrical equipment at nuclear power plants are summarized.

6.2.2.2 Aviation

Aging electrical equipment in the aviation industry poses an actual danger to aircraft since even minor defects in the electrical system may threaten the lives of the passengers and crew. The Federal Aviation Administration (FAA) developed a special research program for investigating aging electrical systems [23]. It was specified that the severity of an electrical system failure is related to both the loss of functionality and the potential for fire or other physical damage to the aircraft. The most often found aging mechanisms in aviation are arc faults, cable degradation, some inconsistent mechanical connections (loose screws), and degradation of connections at high-temperature conditions.

TABLE 6.1
Aging Factors of Electrical Equipment at Nuclear Facilities

Electrical Equipment	Document	Aging Factors
Motor control centers	June 1994 (SAND93-7069)	“Harsh” environments and/or subject to a high number of operating cycles
Electrical switchgear	July 1993 (SAND93-7027)	Lubrication practices, “harsh” environments and/or subject to a high number of operating cycles
Power and distribution transformers	May 1994 (SAN093-7068)	Insulation, insulating fluid, bushing contamination, “harsh” environments and/or subject to a high number of operating cycles

Source: Data from Nakos J.T. and Rosinski S.T. Research on U.S. Nuclear Power Plant Major Equipment Aging, SAND94-2400C, DOE’s. Office of Scientific and Technical Information (OSTI), 1994, Online. Available: <http://www.osti.gov/bridge/servlets/purl/10190825-J7vdeV/webviewable/10190825.pdf>.

6.2.2.3 Chemical and Oil Refining Industries

Degradation of electrical equipment at chemical plants proceeds much faster owing to the presence of higher amounts of various corrosive fumes and gases and very often a higher density of corrosive particles and dust than at other types of industrial facilities. It was found that the electrical equipment at a chemical plant usually has a shorter life than other kinds of equipment of the plant. Modern electrical equipment contain many electronic components, which are very sensitive to their environmental conditions, to chemically and mechanically active substances in particular. The environmental factors included in the specific designs of ventilation and air conditioning systems for control rooms at chemical industrial facilities are climatic and biological conditions and chemically and mechanically active substances. The major aging mechanism of electrical machines in the chemical and oil processing industries is corrosive deterioration of the current-carrying paths, accelerated by the elevated temperature and humidity in the environment of industrial facilities.

6.2.3 AGING EQUIPMENT IN POWER GENERATION AND TRANSMISSION AND DISTRIBUTION

6.2.3.1 Overhead Power Transmission

Overhead transmission lines structures include many components, but not all of them may be defined as actual electrical equipment. However, all these components should be considered when evaluating the degree of aging. The performance and safety of transmission lines strongly depend on the aging of supporting structures, such as wood poles and concrete poles with steel enforcement. Wood poles deteriorate fast because of humidity, losing their mechanical strength. Concrete supports are degraded by corrosion of the steel reinforcement. When steel is corroded, rust forms on steel beam surfaces and triggers the splitting of concrete cover because it is more bulky than steel, which decreases the pole mechanical strength.

Conductors (transmission cables) are exposed to harsh weather conditions such as high temperatures and their variations, rains, sleet, wind, lightning, and so on. Therefore, the climatic condition is a parameter that defines not only the mechanical strength of the transmission network but also causes its degradation. These degradation factors may differ according to the geographic zones.

The deterioration modes of transmission cables include creep, the nonelastic nonlinear behavior of conductors, as well as broken strands caused by sunshine, lightning impacts, and vibration. The cable fittings wear due to the insulator sets swinging caused by wind action [24].

6.2.3.2 Power Plant

At a power plant, there are a number of critical components whose failure could endanger plant safety, could cause an extended forced outage, a long lead time in maintenance and repair, and lost revenues. In a power production plant, the cables and station main transformers are critical components. Power cables and electrical equipment such as motors and transformers must operate as long as possible within reliability and safety standards, which require timely recognition of signs of equipment aging.

The other equipment is called the influence component. This is the equipment whose failure would probably not result in an extended outage, would not endanger plant safety, and is unit specific.

Power cables are used for supplying power to plant equipment, such as large motors, auxiliary transformers, precipitators, and backup diesel generators. These cables are rated from 2 to 15 kV and are single-conductor or three-conductor cables, of shielded or unshielded construction. Before the year 1970, power cables were insulated with extruded dielectrics, such as XLPE, and butyl rubber. In some cases, the PILC cable was also used. The majority of cable failures in an extruded cable system are related to water treeing, which then progresses to electrical trees. Once a water tree progresses to an electrical tree, the time to failure is normally very short because the initiated electrical tree propagates rapidly through the already weakened dielectric (see Section 5.5).

In PILC cables, failures are commonly associated with moisture ingress. Moisture in PILC cables increases the dielectric losses, resulting in localized heat generation that thermally degrades the paper insulation and normally leads rapidly to a cable failure. PD may only be present at advanced stages of such degradation. Cable accessories such as splices and terminations are most likely to fail because of PD that causes degradation [25].

In a *power transformer*, several operating and physical conditions, such as high temperature and high load currents above name plate rating, degrade the transformer cellulose and oil insulation system. Other aging and damaging factors are: moisture inside the transformer, oxidation of cellulose and oil; voltage surges, lightning; and physical damage due to moving and re-locating. As cellulose and oil age, their insulating properties degrade. Degraded insulation produces gases that can form bubbles in the insulating oil (see Section 5.6). These bubbles are where PD may occur. Aging can progress to a level that will lead to failure of the transformer, most commonly in the coil structure.

In addition to insulation aging, the laminated core of a transformer can degrade. Discharge may take place between laminations at locations where the lamination insulation (usually a metal oxide layer) has broken down. Core discharge can take place over a long time period, but usually does not lead to catastrophic failure of the transformer. Transformers typically fail in the core structure.

6.2.4 AGING POWER EQUIPMENT IN A RESIDENTIAL ENVIRONMENT

Examples of distribution electrical equipment include: transformers, fuses, CBs, and other overcurrent protection devices, fixed wiring, switches, outlets, and receptacles, cords and plugs, meters and meter boxes, and so on.

Factors affecting the service life of industrial and residential electrical equipment [26] may be divided into several groups, such as electrical and mechanical stresses and environmental factors. Electrical stresses are excessive loads, overvoltage, harmonics, electrical surges, glowing contacts, and arcing faults. Environmental factors include water and humidity damage, corrosion, heat-related damage.

Important factors in aging of distribution industrial and residential equipment are age-related deterioration, insulation deterioration, and physical damage of wiring or

devices. Added would be other defects initially superimposed by improper original installations, improper additions and modifications, and loose connections and poor workmanship.

In residential areas, aging of residential wiring causes great concerns for fatalities, personal injuries, and loss of property [27]. In 2002, in response to questions regarding the influence of aging and installation quality on the fire safety of electrical systems, the Fire Protection Research Foundation initiated a collaborative research and development project designed to address the issue through a comprehensive survey of the conditions of representative samples of residential electrical components installed in different time periods and U.S. locations. A total of 30 homes were selected from across the United States ranging in age from 30 to 110 years. The report [28] presents a summary of the results of that study; it provides critical information to code writers, especially for NFPA 73, “Standard for Electrical Inspections for Existing Dwellings” [29], and NEC® (The National Electrical Code) [30].

It was reported [28] that the disproportionately high incidence of fire in the electrical systems of older homes can be attributed to one or more of the following factors:

- Inadequate and overburdened electrical systems
- Thermally reinsulated walls and ceilings burying wiring
- Defeated or compromised overcurrent protection
- Misuse of extension cords and makeshift circuit extensions
- Worn-out wiring devices not being replaced
- Poorly done electrical repairs

Apart from the natural effects that age can have on wire insulation and electrical equipment over time, residential electrical systems are seldom inspected after their original installation. In addition to the above, the quality of the original installation may also be a factor, as well as inappropriate upgrades or additions that may have

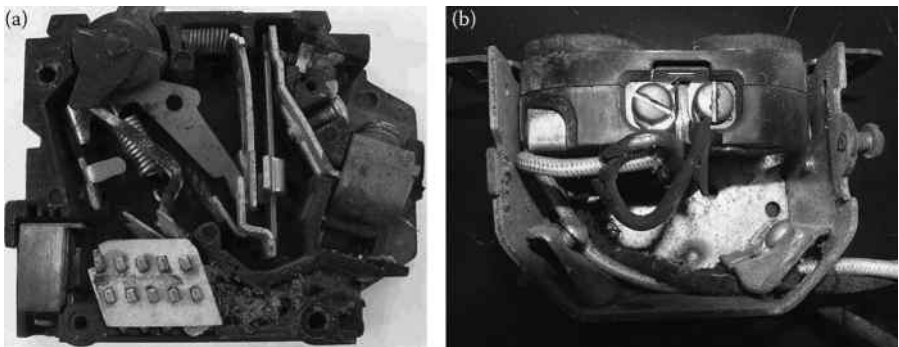


FIGURE 6.1 Examples of aged residential electrical equipment: corrosion damage of the CB (a); brittle rubber insulation (b). (From *Residential Electrical Systems Aging Research Project—Final Report*, The Fire Protection Research Foundation (NFPA), Quincy, MA, pp. 1–62, July 2008, Online. Available: <http://www.nfpa.org/assets/files/PDF/Research/RESAReport.pdf>. With permission.)

been done by unqualified homeowners or others throughout the years. Examples of aged residential equipment are shown in [Figure 6.1](#).

6.2.4.1 Aging of Conductors

Degradation of conductors and insulation increases with age. The following aging factors for conductors and connections in residential electrical equipment should be considered:

- Increased resistance of conductors and at connections, caused by oxidation/corrosion films
- Embrittlement of conductors, caused by excess heat from *overlamped* light fixtures, which happen in old houses when a light fixture has a bulb with a higher wattage than what the fixture is designed for
- Loose or disconnected conductor connections in electrical outlets, switches, and light fixtures
- Conductors deterioration following expansion and contraction due to temperature changes seasonally and daily, as well as by vibrations from trains, sonic booms from jet aircraft, other noisy vehicles, high-decibel-level music/radio equipment, and thunder
- Conductors aging caused by wind and air pressure changes

6.2.4.2 Aging of Insulation

Electrical equipment aging is directly related to deterioration of insulation caused by many factors specific to residential areas [28]:

- Heat from overlamped light fixtures and other installations heavily loaded electrically causes insulation aging
- Continuous exposure to light causes insulation deterioration by accelerating loss of plasticizer in insulation
- Dry locations lead to loss of the plasticizer in PVC insulation, which depends on the length of time and high-temperature factors as well
- Water absorption into insulation in wet locations reduces its dielectric strength
- Rodents and other creatures can damage insulation over the years

6.2.5 AGING ELECTRICAL EQUIPMENT IN RURAL/AGRICULTURAL APPLICATIONS

In rural areas there are multiple aging factors that are different from those in industrial and residential areas, which required establishing a set of codes and standards specific to rural areas [31]. These include applications to grain bins, storage structures, irrigation pump motors, oil pumps, other motor applications, animal confinement buildings, and wet or corrosive installations. These documents standardize methods of grounding and wiring, as well as set up the rules of equipment selection. One of the major concerns in rural areas is aging transmission lines that are exposed to the rural environment much longer than in industrial areas without proper maintenance and replacement [32].

Agricultural buildings that house livestock require special care when selecting wiring materials, wiring methods, and electrical equipment because of corrosive dust, gases, and moisture. Corrosion of metallic conduit, boxes, and fixtures frequently leads to electrical system failure. Boxes and fixtures made of a nonmetallic material or corrosion-resistant stainless steel, that is, nonmagnetic, are recommended for all agricultural buildings and are required in any buildings that house livestock or contain corrosive dust. Accelerated corrosion due to condensation occurs on electrical panels that have not been properly designed [33].

Electrical enclosures are often made of galvanized steel. Galvanized structures corrode when the protective zinc coating has been corroded away by acid or salty environments (or by strong alkali). In rural environments, galvanized sheet may well last more than 30 years, but life in a severely polluted farming areas may be only 5–10 years. Galvanized steel does not satisfactorily withstand aggressive soils (e.g., peats or marshes containing sulfates and chlorides) or acid conditions that may occur at ground level in some buildings, nor can it withstand the severe condensation that is not uncommon in some farm buildings [34].

Electrical devices may experience very severe corrosion attack at or near piggeries and poultry houses. These agricultural facilities usually have an internal atmosphere which can contain high concentration of ammonia. This gas is damaging for most of the materials that electrical apparatus is built of. In poorly ventilated enclosures, acid vapors emitted by timber as part of the natural seasoning process can corrode metals that are nearby but not actually in the contact. Excessive corrosion can result in a variety of defects such as seizure of moving parts, distortion of metering equipment, blocked outlets, and so on, which can seriously affect the functioning of electrical machinery. Most corrosion damage occurs in poorly drained areas that remain damp and dirty, for example, in overlapped joints, on spot-welds and in crevices generally, and on moving parts, for example, hinges.

Some of the major harmful effects of corrosion can be summarized as the loss of technically important surface properties of any metallic component. These could include frictional and bearing properties, and electrical conductivity of electrical contacts [35].

6.3 FAILURE MODES AND FAILURE RATES OF AGING ELECTRICAL EQUIPMENT

6.3.1 DEFINITIONS OF FAILURE, FAILURE MODE, AND FAILURE RATE OF ELECTRICAL EQUIPMENT

Failure is any trouble with a power system component that causes any of the following to occur: (1) partial or complete plant shutdown, or below-standard plant operation; (2) unacceptable performance of the user's equipment; (3) operation of the electrical protective relaying or emergency operation of the plant electrical system; and (4) de-energization of any electrical circuit or equipment. This definition of failure is given in IEEE Gold Book™ Standard 493™-2007, "IEEE Recommended Practice for the Design of Reliable Industrial & Commercial Power Systems" [36].

A failure on a public utility supply system may cause the user to have either a power interruption or a loss of service or a deviation from the normal voltage or a frequency outside the normal utility profile. A failure of an in-plant component causes a forced outage of the component; that is, the component is unable to perform its intended function until it is repaired or replaced. The terms “failure” or “forced outage,” which is an outage that cannot be deferred, are often used synonymously.

Failure rate is defined as the mean number (arithmetical average) of failures of a component per unit exposure time. Usually, exposure time is expressed in years and failure rate is given in failures per year.

Distribution system components, such as lines, transformers, and CBs, are subject to a variety of failure modes. The failure modes have different impact on system reliability performance. It is sometimes useful to categorize system components as switching devices (such as CBs) or nonswitching devices (such as lines and transformers) [36].

Failure modes for nonswitching components are the events that make the component unable to fulfill its current-carrying function, generally due to a fault and the subsequent isolation of the fault component by a protective device. For switching devices such as CBs or protection systems, which have both a continuously required current-carrying function and response functions, failure modes would make them unable to perform both functions. An inability to perform a current-carrying function will immediately impact the whole electrical system performance, while an inability to perform a response function, such as tripping open on command, will be manifested only when the response is required.

According to the IEEE Gold Book [36] a common cause of electrical failure is dust and dirt accumulation and the presence of moisture. This can be in the form of lint, chemical dust, day-to-day accumulation of oil mist and dirt particles, and so on. These deposits on the insulation, combined with oil and moisture, become conductors and are responsible for tracking and flashovers. Deposits of dirt can cause excessive heating and wear, and decrease apparatus life. Moisture condensation in electrical apparatus can cause copper or aluminum oxidation and connection failure.

Loose connections are another cause of electrical failures. Creep or cold flow is a major cause of joint failure. Friction can affect the freedom of movement of devices and can result in serious failure or difficulty. Dirt on moving parts can cause sluggishness and improper electrical equipment operations such as arcing and burning.

6.3.2 THE BATH TUB CURVE, THE HYPOTHETICAL FAILURE RATE VS. TIME

The statistical failure rates rise over the years in service according to the well-known bath tub curve (Figure 6.2). The bath tub curve consists of three periods: (1) an infant mortality period with a decreasing failure rate followed by (2) a normal life period (also known as “useful life”) with a low, relatively constant failure rate. The curve is concluded with a wear-out period (3) that exhibits an increasing failure rate [37]. The bath tub curve displayed in Figure 6.2 describes the relative failure rate of an entire population of products over time.

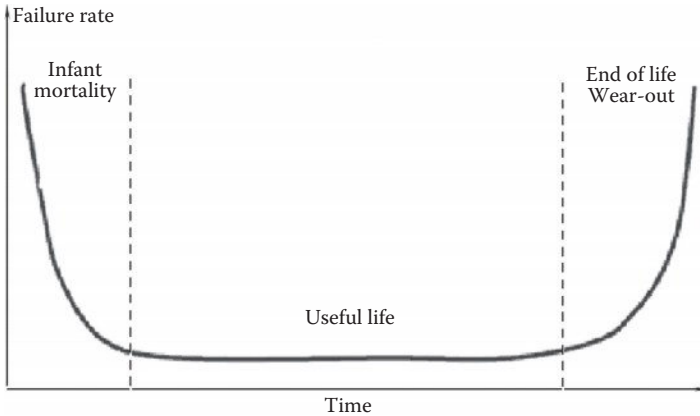


FIGURE 6.2 The bath tub curve: hypothetical failure rate versus time.

The bath tub curve is typically used as a visual model to illustrate the three key periods of product failure and not calibrated to depict a graph of the expected behavior for a particular product family. Some individual units will fail relatively early (*infant mortality* failures), others will last until wear out and end of life, and some will fail during the relatively long period typically called *normal (or useful) life* [37]. Failures during infant mortality are highly undesirable and are always caused by defects and blunders: material defects, design mistakes, errors in assembly, and so on. Normal life failures are normally considered to be random cases of “stress exceeding strength.”

However, many failures often considered normal life failures are actually infant mortality failures. Wear-out is a fact of life due to fatigue or depletion of materials. A product’s useful life is limited by its shortest-lived component. A product manufacturer must ensure that all specified materials are adequate to function through the intended product life.

6.3.3 FAILURE CAUSES OF CBs

6.3.3.1 LV and MV CB Failure Causes

The U.S. Nuclear Regulatory Commission (NRC) collected and summarized the data on CCF of LV and MV CBs from 1980 to 2000, which are presented in Ref. [38]. The data studied in the report were derived from the NRC CCF database, which is based on U.S. commercial nuclear power plant event data. The report states that in a CB, each component fails because of its susceptibility to the conditions created by the root cause.

By the definition given in Ref. [38] a *proximate cause* of a failure event is the condition that is readily identifiable as leading to the failure. The proximate cause can be regarded as a symptom of the failure cause, and it does not in itself necessarily provide a full understanding of what led to that condition. As such, it may not

be the most useful characterization of failure events for the purposes of identifying appropriate corrective actions.

The proximate cause classification consists of six major groups or classes:

- Design/construction/installation/manufacture inadequacy
- Operational/human error
- Internal to the component, including hardware-related causes and internal environmental causes
- External environmental causes
- Other causes
- Unknown causes

The causal chain can be long and, without applying a criterion, identifying an event in the chain as a “root cause” is often arbitrary. Identifying root causes in relation to the implementation of defenses is a useful alternative. The root cause is therefore the most basic reason or reasons for the component failure, which if corrected, would prevent recurrence.

The leading proximate cause of the report [38] was “internal to component” and accounted for about 61% of the total events. “Design/construction/installation/manufacture inadequacy” faults accounted for 18% of the total. Human error accounted for 13% of the total events. To a lesser degree, the “external environment and the other causes” proximate cause categories were assigned to the CB component.

6.3.3.2 Failures of Circuit Breakers According to the *IEEE Gold Book*

Failure modes of CBs are summarized in IEEE Gold Book™ Standard 493™-2007, “Recommended Practice for the Design of Reliable Industrial & Commercial Power Systems” [36].

The largest percentage of CB failures (i.e., 42%) were of the type “opened when it should not,” which is a primary concern for industrial plants and makes this the number one failure mode of CBs. This type of CB failure can significantly affect plant processes and may result in total plant shutdown.

Also, a large percentage (i.e., 32%) of the CBs “failed while in service (not while opening or closing),” which is the second most common failure mode of CBs. During this time, the CB could not have performed its designed primary function, which is protection against overcurrent. The above information is given for all types of CBs.

For CBs up to 600 V types, it was found that the highest percentage of failures of metal-clad draw-out CBs (71%) occur when the breaker “opened when it should not,” while only 5% of fixed-type breakers (including molded case circuit breakers (MCCB)) experience this type of failure.

The alarming statistic for molded case breakers is that the “failed while in service” is 77%. This shows the lack of ability of the molded case CB to perform its primary function, which is protection against overcurrents. This is not surprising since typically the molded case CB does not have maintenance performed on it.

It was found [36] that 43% of CB failures were caused by flashovers or arcing of all types, 19% of breakers failed because of other electrical defects, and mechanical

defects caused 11% of CBs failures. After failure, damaged insulation of all types was found in 17% of the breakers, mechanical damage (bearings, other moving parts, and other mechanical parts) was found in 18% of the breakers, and in 28% of failed breaker protective devices have been damaged.

6.3.4 FAILURE CAUSES AND FAILURE RATES OF POWER TRANSFORMERS

6.3.4.1 MV and LV Power Transformers

On the basis of the IEEE survey [39,40], failure rates for liquid-filled power transformers for all subclasses from 300 to 10,000 kVA were approximately equal for three age groups (1–10 years old, 11–25 years old, and older than 25 years). The slightly higher failure rates for transformer units aged 1–10 years and for units older than 25 years may be attributed to “infant mortality” and to units approaching the end of their life, respectively.

The major *failure-initiating* causes for *power transformers* leading to the highest percentage of failures are found to be the following: transient overvoltage disturbance (switching surges, arcing ground fault, etc.) resulting in 16.4% of failures, winding insulation breakdown (29.1%), and insulation bushing breakdown (13.6%). Other failure causes are: mechanical breaking, cracking, loosening, abrading, or deforming of static or structural parts (7.3%), loose connection or termination (7.3%), and so on.

For *rectifier transformers*, about 40% of all failures are caused by breakdown of winding, bushings, and other insulation breakdown, and 20% of all failures caused by mechanical breaking, cracking, loosening, abrading, or deforming of static or structural parts. Other failure causes are transient overvoltage disturbance (13.3% of failures) and mechanical burn-out, friction, or seizing of moving parts (13.3% of all failures). Overheating of rectifiers transformers caused 6.7% of all failures vs. 2.7% of failures of power transformers.

Normal deterioration from age and cooling medium deficiencies were reported to have contributed to a large number of both power transformers (13.3%) and rectifier transformer (28.6%) failures.

It is important also to know what the most important *failure-contributing* causes for all power transformers are. It was found [5] that exposure to aggressive chemicals, solvents, dusts, moisture, or other contaminants contributed to 14.4% of failures. Also environmental conditions such as abnormal temperature (contributed to 5.5% of failures) and severe wind, rain, snow, sleet, or other weather conditions (4.4% of failures) play an important role in power transformer failures. Loss, deficiency, contamination, or degradation of oil or other cooling media contributed to 10.0% of all failures of power transformers.

6.3.4.2 HV Power Transformers

In several studies and surveys it was found that problems with bushings are a major source of HV transformer failures [5]. One study [41] of 106 aged (23–39 years old) 110–500 kV transformers noted bushing defects in 70% of the transformers surveyed. The same survey also concluded that transformer life is limited by the deterioration of accessories, of which were listed just three: bushings, LTC, and the

cooling system. Over 46% of transformer defects were found to be attributable to these items [41,42].

Another study [43] from the 63 members of the Edison Electric Institute lists bushings amongst the three most common transformer failure modes reported. Australian and New Zealand reliability statistics [44] in a survey on 2096 transformers in 1970–1995 found similarly that bushings were second only to tap changers as the component initially involved in failure and were amongst the top three contributors to costly transformer failures.

Reported findings from European statistics [45] indicate that bushing failures cause 30% of transformer failures but that 80% of bushing failures occur between 12 and 20 years in service or at mid-life of the transformer population. It was also confirmed that a bushing or high-voltage CT failure may often be followed by a catastrophic event such as fire, tank rupture, violent explosion of the bushing propelling large broken shards of porcelain some hundreds of meters at velocities enough to imbed the material in concrete walls [5].

6.3.5 FAILURE CAUSES OF MV SWITCHGEAR

Multiple defects may be listed as causes of switchgear failures [46]. Loose and faulty connections may cause complete thermal failure of the connection due to the heat created by increased resistance. It was estimated that approximately 25% of all electrical failures occur due to loose connections. Medium-voltage insulation is exposed to voltage stresses that may lead to a failure.

The cables are connecting switches to transformers, potential transformers, control power transformers, and surge arresters to the bus; and connecting transformer coils and taps together. If these cables come in contact with the ground, other phases, or even with other types of insulation used for supporting them, they will likely develop stresses at those points that will lead to a future failure. Cable terminations can also create localized partial insulation breakdown or PD that will lead to failure.

Bus insulation barriers for separating compartments and supporting the bus often have small air gaps between the bus and the insulation. The localized voltage stress is great enough to cause partial breakdown or PD that may lead to failure.

A medium-voltage switchgear that is exposed to high-humidity conditions will absorb moisture, and voltage stresses will attack the hydrophobic insulation surfaces which are designed to inhibit moisture absorption. Water inside the switchgear can create instant short circuits, long-term insulation damage, and long-term metallic component corrosion, among other complications that may lead to failure.

It is sometimes difficult to obtain definitive information on the causes of faults in MV switchgear; however, some information is always available and it can be used as a guide to the typical problems faced.

On the basis of the faults in MV vacuum switchgear operating on electricity distribution networks within the United Kingdom, the distribution of the failure causes has been determined [47]. The fault information included defects identified during operation or maintenance as well as disruptive failure of the switchgear. The biggest contributors to faults are mechanical problems that caused 30% of the faults and maloperations that caused 8% of the failures.

The second largest fault cause was associated with PD activity (26%). It should also be noted that faults reported with cable termination boxes (6%), voltage transformers (VTs) (9%), and current transformers (CTs) (3%) are often associated with PD activity and therefore the actual figure for PD-related problems actually lie somewhere between 26% and 44%.

The general construction of SF₆ switchgear is comparable with vacuum switchgear and it would be reasonable to suggest that a similar fault breakdown will also exist for MV SF₆ switchgear. The situation is slightly different when it comes to oil-filled switchgear. Much research has been carried out into how bulk oil-filled switchgear ages and degrades and it has been established that the condition of the oil is a key indicator of the overall condition of the switchgear [37,38].

6.3.6 FAILURE CAUSES OF OTHER MV AND LV POWER ELECTRICAL EQUIPMENT

In the case of electrical equipment other than MV CBs and transformers, analysis of failures [36] shows that most of the motor starters, disconnect switches (DS), bus ducts, wires, and cables “failed in service” (Table 6.2).

Based on the survey it appears that a majority of failures were caused by flashovers or arcing of all types in bus ducts (100%), cables (74%), cable joints (79%), and cable terminations (59%) [36]. A large percentage of insulation has been found damaged during failure of bus duct and cables and their accessories (joints and terminations), while mechanical parts (bearings, other moving parts, and other mechanical parts) were found mostly damaged in the motor starters and DS (Table 6.3).

There are multiple suspected failure-initiating and failure-initiating causes for all types of electrical equipment. In Tables 6.4 and 6.5 these causes are listed with the percentage of failures.

It is important to note that about a quarter of the CBs, motor starters, DS and bus ducts failed because of some damaged components installed by manufacturers.

TABLE 6.2
Dominant Failure Characteristics of Electrical Equipment

Type of Equipment	Failed in Service (%)	Failed during Testing (%)	Damage Discovered during Testing or Maintenance (%)
Motor starters	37	6	36
Disconnect switches	72	3	18
Bus duct	90	5	0
Open wire	68	2	1
Cable	92	2	2
Cable joint	96	4	0
Cable terminations	80	2	12

Source: Modified from IEEE Gold Book™ Standard 493™-2007, *IEEE Recommended Practice for the Design of Reliable Industrial & Commercial Power Systems*, IEEE Publications, New York, NY, 2007, 383 pp. © 2007, IEEE.

TABLE 6.3
Damaged Parts during the Failure of Electrical Equipment

Type of Equipment	Insulation— Winding (%)	Insulation— Bushings (%)	Insulation— Other (%)	Mechanical Parts (%)
Motor starters	5	0	10	18
Disconnect switches	0	1	14	39
Bus duct	15	10	65	0
Open wire	0	1	6	4
Cable	5	0	83	4
Cable joint	0	0	91	0
Cable terminations	0	12	74	4

Source: Modified from IEEE Gold Book™ Standard 493™-2007, *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*, IEEE Publications, New York, NY, 2007, 383 pp. © 2007, IEEE.

Improper application of the apparatus caused half of the motor starters failures; and the majority of cable joints and terminations failed due to inadequate installation and testing prior to startup.

6.3.7 FAILURE CAUSES OF POWER CONNECTORS

There are multiple failure causes of power connectors: extreme environments, the use of incompatible materials, inappropriate use of materials, insufficient maintenance, as well as manufacturing flaws.

TABLE 6.4
Major Failure-Initiating Causes of Electrical Equipment Failures

Type of Equipment	Manufacturer Defective Component (%)	Improper Application (%)	Inadequate Installation and Testing Prior to Startup (%)	Inadequate Operating Procedures (%)
CBs	23	4	3	6
Motor starters	18	51	0	3
Disconnect switches	29	6	4	39
Bus duct	26	16	5	0
Open wire	0	2	9	2
Cable	16	8	14	3
Cable joint	0	0	50	0
Cable terminations	0	18	38	0

Source: Modified from IEEE Gold Book™ Standard 493™-2007, *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*, IEEE Publications, New York, NY, 2007, 383 pp. © 2007, IEEE.

TABLE 6.5
Major Failure-Contributing Causes of Electrical Equipment

Type of Equipment	Exposure to Aggressive Chemicals (%)	Exposure to Abnormal Moisture or Water (%)	Severe Weather Conditions (%)	Normal Deterioration from Age (%)
CBs	2	3	1	17
Motor starters	0	0	0	40
Disconnect switches	0	4	0	5
Bus duct	0	17	11	49
Open wire	28	1	30	3
Cable	14	8	16	30
Cable joint	13	22	2	29
Cable terminations	10	12	16	24

Source: Modified from IEEE Gold Book™ Standard 493™-2007, *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*, IEEE Publications, New York, NY, 2007, 383 pp. © 2007, IEEE.

6.3.7.1 Aluminum Connectors

Aluminum is a widely used material in power connectors, and this metal has several physical properties that can ultimately lead to failure. An insulating oxide layer building on an aluminum surface can reduce the metal’s ability to form a strong connection to another aluminum component. In a connector, this can be especially harmful, as the device depends on the primary connection between two (often aluminum) wires. Additionally, aluminum is prone to thermal expansion, corrosion, fretting, and stress relaxation, all of which can further compromise the connector’s ability to transmit electricity via a strong aluminum-to-aluminum contact.

6.3.7.2 Corrosion

Corrosion is a common concern in connectors that are exposed to extreme conditions or outdoor environments, which first begins with the development of a thin film on the connector’s contacts. As the film builds, the contacts’ ability to conduct electricity between one another can be lost. Different metals react to surface films in different ways. Some metals are extremely corrosion resistant, but may be more prone to other issues, such as fretting.

6.3.7.3 Contact Fretting

Fretting corrosion is a form of accelerated atmospheric oxidation which occurs at the interface of contacting materials undergoing slight cyclic relative motion. In electrical contacts involving nonnoble metals, fretting action can cause rapid increases in contact resistance (CR), proceeding to virtual open circuits in a matter of minutes in the worst cases. Fretting corrosion is a build-up of insulating, oxidized wear debris that can form when there is small-amplitude fretting motion between electrical contacts. More about fretting corrosion is given in Section 2.5. When two different

metals are used, such as nonlubricated aluminum and copper, heat can cause one metal to expand at a different rate than the other. In the case of nonlubricated aluminum and copper, aluminum expands faster than copper, compromising their connection and leading to fretting. To avoid contact fretting, simply lubricating the contact material can make a significant difference.

6.3.7.4 Stress Relaxation

When a connector is under a high amount of pressure over an extended period of time, stress relaxation can occur. Because of the amount of pressure, the metallic contact undergoes a shift in structure (and not in dimension) causing the connection to weaken and the pressure between the contacts to slacken. If a connector is exposed to high temperature, stress relaxation intensifies and the results are more severe. With aluminum in particular, increased temperature aggravates stress relaxation.

6.3.8 INADEQUATE MAINTENANCE AND MAINTENANCE QUALITY
AS A CAUSE OF FAILURE

Maintenance quality has a significant effect on the percentage of all failures blamed on “inadequate maintenance,” as was found in the survey [4]. Of the 1469 failures reported from all causes, “inadequate maintenance” was blamed for 240, or 16.4% of all the failures. Twelve main classes of electrical equipment have been surveyed and presented in the IEEE Gold Book [36]. The results are based on information received from 30 companies, covering 68 plants in nine industries in the United States and Canada.

The percentage of electrical equipment failed when improper maintenance was suspected as a failure-initiating cause [36] is shown in Table 6.6. This information might be outdated, since the survey was performed in 1972, and with the continuous

TABLE 6.6
Inadequate Maintenance as a Failure-Initiating
Cause of Electrical Equipment

Type of Equipment	Inadequate Maintenance (%)
CBs	23
Motor starters	8
Disconnect switches	13
Bus duct	16
Open wire	30
Cable	10
Cable joint	18
Cable terminations	32

Source: Modified from IEEE Gold Book™ Standard 493™-2007, *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*, IEEE Publications, New York, NY, 2007, 383 pp. © 2007, IEEE.

improvement of maintenance strategies and enforcement of preventive maintenance implementation in the majority of industrial and power facilities, the situation would improve in the twenty-first century.

The IEEE data [39] also showed that “months since maintenance” is an important parameter when analyzing the failure data of electrical equipment. Analysis of the number of failures caused by “inadequate maintenance” for CBs, motors, open wire, transformers, and all equipment classes combined showed that the percentage of failures attributed to “inadequate maintenance” is in close correlation with the number of months ago that the equipment was maintained. Thus, 77.8% of circuit breakers, 44.4% of motors, and 36.4% of transformers, in which the failures were caused by “inadequate maintenance,” failed after being maintained more than 24 months ago.

It is important to realize that maintenance and testing are needed due to the fact that nearly 1/4 of all CB failures were caused by a manufacturer defective component and nearly another 1/4 of all CB failures were due to inadequate maintenance. Thus, if proper maintenance and testing are performed, potentially 50% of the failures could be eliminated or identified before a problem occurs. The results of the 1996 IEEE study show that better technology has improved the failure rate of low-voltage power CBs and could potentially be cut by almost half, but maintenance and testing are still needed.

NFPA 70B, “Recommended Practice for Electrical Equipment Maintenance” [48], makes a very clear statement about an effective Electrical Preventive Maintenance (EPM) program: “Electrical equipment deterioration is normal, but equipment failure is not inevitable. As soon as new equipment is installed, a process of normal deterioration begins. Unchecked, the deterioration process can cause malfunction or an electrical failure. Deterioration can be accelerated by factors such as a hostile environment, overload, or severe duty cycle. An effective EPM program identifies and recognizes these factors and provides measures for coping with them.” Further development of preventive maintenance techniques and its influence on the performance and longevity of electrical equipment will be discussed in Chapter 8.

6.4 FAILURE CAUSES AND RATES OF ELECTRICAL EQUIPMENT BASED ON CIGRÉ SURVEY

CIGRÉ (International Council on Large Electric Systems) is one of the leading worldwide organizations on electric power systems, covering their technical, economic, environmental, organizational, and regulatory aspects. Electrical networks worldwide have an increasingly aged population of electrical equipment. Before the latest CIGRÉ survey started in 2004, the results of two other surveys have been published.

The first CIGRÉ survey covered the time interval 1974–1977, which included all types of CBs with service voltage above 63 kV (published in *Electra* No. 79, 1981). The second CIGRÉ survey, which covered the time interval 1988–1991, was published in CIGRÉ Technical Report 83, 1994. It included single pressure SF₆ CBs (live tank, dead tank, and the breakers at gas insulated substations (GIS)), placed in service in 1978–1991; the lowest rated voltage was 72.5 kV. There was no age limitation to equipment population.

During 4 years (January 2004–December 2007) CIGRÉ was carrying out a worldwide survey of failures in service on high-voltage equipment rated for voltages

greater than or equal to 60 kV. The survey based on the information from utilities about their equipment populations covered SF6 CB; DS, earthing switches (ES), IT, and GIS.

When the data acquisition was completed, the information was subjected to extensive statistical analyses with the purpose of obtaining trustworthy information on reliability and failures for the considered component types. The survey's application helps the owners and operators of these networks to understand the impact of aged equipment on network performance and helps mitigate the effects through proper operation, effective maintenance, monitoring, asset refurbishment and asset replacement.

Basically, two different failure rates may be estimated based on survey data: absolute failure rates and failure rate with age [49].

Absolute failure rates. The data can be used to derive a failure rate, typically the number of failures per 100 years, for a particular family of high-voltage equipment. This failure rate can then be used for example at the initial life of the asset to ensure that the application of the high-voltage equipment is consistent with the expected failure rate. The absolute failure rate has a number of uses during the operating phase of the asset and, for example, can assist in determining the optimum number of spares.

Failure rate with age. The survey includes questions regarding the age of the failed items and the age profile of the population. This allows determining the failure rate for different ages of equipment. It should be noted that as design and maintenance practices change over time, it is not possible to assume that any definitive age profile or bath tub curve can be found. However, with care such information should enable maintenance to be more targeted and should help inform the difficult decision on when to refurbish or replace an item of high-voltage equipment.

Types of the failures. Two different types of failure may be considered: major and minor [50]. By the definition of CIGRÉ, *failure* is a lack of performance by an item of its required function or functions. The occurrence of a failure does not necessarily imply the presence of a defect if the stress or the stresses are beyond those specified.

Major failure (MF). MF is a failure of a switchgear or control gear which causes the cessation of one or more of its fundamental functions. An MF will result in an immediate change in the system operating conditions, for example, the backup protective equipment being required to remove the fault, or will result in mandatory removal from service within 30 min for unscheduled maintenance, or will result in unavailability for the required service.

Minor failure (mf). Minor failure (mf) is a failure of equipment other than a major failure (MF) or any failure, even complete, of a constructional element or a subassembly which does not cause an MF of the equipment.

6.4.1 RESULTS OF THE OLDER CIGRÉ SURVEYS OF HV CB FAILURES

The results of two past CIGRÉ surveys (1974–1977 and 1988–1991) have been compared in Ref. [50].

6.4.1.1 Main Results of the First Survey

- 70%—MF of mechanical origin
- 19%—MF of electrical origin concerning the auxiliary and control circuits
- 11%—MF of electrical origin concerning the main circuit
- 48%—MF classified as “Does not open or close on command”

The *operating mechanism* was the part of the CB responsible for the highest number of failures (37% of MF). Different types of operating mechanism have about the same MF rate. Most of the minor failures of operating mechanisms are either hydraulic oil or air leakages. The minor failure rate of spring, pneumatic and hydraulic drive systems is 1:2:7, respectively.

The percentage of failures in *auxiliary interrupters or resistors* of CBs with rated voltage 500 kV and above was of the same order as the percentage of failures in *making and breaking units*.

Compared with the first survey, in the second survey it was determined that the MF rate for single pressure SF₆ CBs is about 40% of the value in the first survey (for CBs of all technology), and the minor failure rate is about 30% higher than in the first survey. This might be explained by SF₆ leakage problems and more complex control and auxiliary systems of modern CBs. The MF rate increases rapidly with voltage, but in comparison with the first survey the improvement in the higher voltage ranges is much greater, due to improved design.

In reviewing the survey results, the maintenance and mechanical aspects should be considered.

6.4.1.2 Maintenance Aspects

- The average interval between scheduled overhaul is 8.3 years, which in many cases could be extended
- The number of failures caused by incorrect maintenance has decreased compared to the first enquiry (85% decrease for MFs and 26% for minor failures), but there is still room for improvement
- About a quarter of the failures are caused by inadequate instructions and incorrect erection, operation, and maintenance

6.4.1.3 Mechanical Aspects

- As with the first enquiry, a majority of the MFs have mechanical origin
- The operating mechanism and the electrical control and auxiliary circuits are the components responsible for the majority of both major and minor failures
- The dominant MF modes are “Does not open or close on command” and “Locked in open or closed position.” These modes add up to almost 70% of the MFs

6.4.2 FAILURE CAUSES OF GIS

6.4.2.1 Older CIGRÉ Surveys

The first CIGRÉ survey on GIS was published in 1992–1994; it covered the experience up to 1990 and was based on information from both manufacturers and

users. The second survey was published in the final form in 2000 CIGRÉ Technical Brochure 150 and covered the experience up to 1995; it was based on information from users only. Both surveys covered the whole population of GIS, including apparatus, and all failures without age limitations. At this time the GIS was still a relatively new technology, average age 9 years.

Comparison of the results from the first and second CIGRÉ GIS surveys showed an increasing reliability of GIS in service. Total downtime due to failure was 13 days on average. There are three components most frequently involved in MFs: CB or switch, bus bar or bus duct, and disconnector.

About 50% of all failures are dielectric breakdowns, which occur during normal service. About 50% of all failures are claimed to be caused by inadequate design and manufacture. SF₆ tightness is reported to be better than standard requirements; the majority report 0.5% leakage per year.

6.4.2.2 Major GIS Failure Modes

In the first decade of the twenty-first century (January 2004 to December 2007) CIGRÉ was carrying out a survey based on the information from utilities about their equipment population of SF₆ CBs and GIS. During the previous CIGRE surveys, GIS was still a relatively new technology; however, in the latest survey, 55 utilities from 24 countries participated in the 2004–2007 survey. The data of this survey [51,52] determined the following major GIS failure modes:

- Failing to perform requested operation—63%
- Dielectric breakdown—23%
- Loss of mechanical integrity—4%
- Loss of electrical connections integrity in primary and secondary circuits—1%
- Other modes—9%

6.4.2.3 Age of CIS and Major Failure Mode Distribution

For older breakers (manufactured before 1993), the MF mode is still “Failing to perform requested operation,” but at higher rate, ~80%. However, the dielectric breakdown failure mode (in normal service without switching operations) was determined much less often in older GIS (45 and 12% for GIS made before 1884 and in 1984–1993, respectively). In new CIS built after 1994, the dielectric breakdown failure mode plays a major role in the failures, about 43%. Loss of mechanical integrity (3–6% in older GIS) was not found to be responsible in any MFs of new GIS.

6.4.2.4 Location, Origin, and Environmental Contribution in GIS Major Failure

An important observation was location distribution of failures: about 80% of all MFs happened in outdoor GIS, with the rest (20%) MFs occurring in indoor GIS. It was found that 18% of all GIS MFs originated from mechanical parts other than the operating mechanism; 24% originated from the operating mechanism, while electrical main and secondary circuits were specified as the origin of failure in 11 and 38%, respectively. The environment was not found to be contributing into 88% of all failures.

6.4.2.5 Component and Voltage Class of CIS

The frequency of GIS MFs depends on voltage classes and type of GIS equipment: CBs, IT, DS, ES, and other components (bus bars and bus ducts). For example, it was found that for GIS > 700 kV, the majority of failures involved CBs (100%). However, for GIS of lower voltage (60–100 kV) CBs caused about 27% of failures, with the “weak link” being DS/ES (60% of all failures). CBs have been found to cause failures in about 50% of all GIS failures for GIS classes from 300 to 700 kV. For all voltage classes the ITs’ role in GIS failures was about 5%, while CBs caused about 34% of all failures. Switches caused almost half of the GIS failures of all voltage classes [52].

The data clearly demonstrated the correlation of MF rate and age of the GIS. MF rate tripled for the GIS manufactured before 1984 compared with the newest GIS built in 1994–2005. MF rate was more than twice higher for older GIS than for those manufactured in 1984–1993. Various voltage classes of GIS of different ages experience different rates of MF. The oldest GIS MF rate was highest for the substation of the class 300–500 kV and lowest for the class 200–300 kV [51].

6.4.2.6 Age of GIS Components

Depending on GIS age, different components failed. For example, in older GIS manufactured before 1993, the distribution of failed components is about the same: CBs failed in about 45% MF, switches (DS and ES) failed also in about 45% of the cases. The rest of the failures were caused by the failure of bus bars/bus ducts and ITs. But in new GIS manufactured in 1994–2005, the roles of the components in MFs changed; it was found that the failures of bus bars/bus ducts and ITs grew significantly and caused about 33 and 7%, respectively, of all failures. The failures of CBs and switches of all types play a lesser role (~22% and ~37%, respectively) in MF events of new GIS than of older GIS [51].

6.4.2.7 Service Conditions of Major Failure Discovery

Analysis of survey data shows that the majority of GIS failures were discovered during switching operation either using CBs or switches (51%); the second largest discovery was during normal service (31%); 10% of all MF was found during testing and maintenance, and the rest was found in de-energized condition or during operation (each about 4%).

6.4.2.8 Time of MF Cause Introduced

The new survey also determined when the cause of the GIS MF was introduced, considering two important periods: during a period of putting GIS in service or during service.

Multiple conditions during the service are included in survey, such as current in excess of rating, mechanical stress in excess of rating, various environmental stresses, corrosion, wear and aging, incorrect operation, incorrect monitoring and so on. Electrical and mechanical failures of adjacent equipment, human error, incorrect maintenance, external damage caused by animals, humans, and other factors may also play an important role in introducing failures.

It was found that in older GIS, the cause of most GIS failures (64%), was introduced before GIS was put into service, while in only 28% of GIS MFs the cause was introduced

during service. In new GIS built after 1994, this relation was reversed: in 61% of all GIS MFs, the cause was introduced during service, and only in 17% of all GIS failures, the cause was introduced during the period before GIS was put into service [51].

6.4.2.9 Age of the CIS and Primary Cause of the Failure

In the older CIS, the primary cause of failure was attributed to wear and aging (50–60%), while in new GIS these cause only about 12%, which is reasonable for recently built substations. The role of incorrect maintenance was decreasing with age from about 10% for the oldest GIS to 3% for the newest GIS. And the reverse relation to age was found for the role of manufacturing faults, which increased 10 times from 5% for the oldest substations to 20% for MFs of GIS.

6.4.2.10 Failure Rates of GIS Components

According to Ref. [53] the role of various components of GIS failures is distributed almost evenly between three major groups. Among all components, CBs or switches are most often involved in MF of 300–500 kV GIS (27.3%), the next components most often involved in failure are bus ducts and interconnecting parts (24.2%), and the third type of components most often involved in failure are the disconnectors (20.5%). SF₆ air bushings (9.3%), bus bars (6.2%), voltage and CTs (4.3% and 1.9% respectively) play a lesser role in major HV GIS. Much less often transformer interfaces are involved in MF (2.5%) and surge arresters (1.9%).

6.4.3 FAILURE CAUSES OF SF₆ CBs

Latest CIGRE survey data on CBs failure causes were reviewed in Ref. [54]. It was found that in most failures (93%) environmental circumstances did not play any role; however, in the rest (7%) of all MFs, the environment contributed to the failure. Among the components of CBs, the operating mechanism plays a leading role in MFs (82% of all failures), and electrical control and auxiliary circuits caused 67% of all MFs.

The role of the operating mechanism in MFs was found to depend on the age of CBs; thus, a lesser number of failures were caused in older CBs built before 1984 than in CBs built in 1994–2003. As to the failures caused by electrical control and auxiliary circuits, the finding is the reverse: a greater number of failures were caused by these circuits in older breakers than in newly built CBs.

MF rate is found to be directly related to the age of CBs, going from 87% for the breakers built before 1984 to 78% for breakers manufactured in 1985–1993, and down to 68% for new breakers built in 1993–2003.

Based on the latest survey of SF₆ CBs reliability, the main conclusions are:

- The majority of the CBs are used at service voltages between 60 and 200 kV
- The majority of the CBs are installed outdoors
- 54% of the CBs are used for overhead line switching
- The most widely used type of operating mechanism has changed from hydraulic to spring design
- Most of the failures seem to happen during normal service

- Leakage of SF₆ or oil seems to remain a problem
- Operating mechanisms are still the most often reported components responsible for MFs

6.4.4 FAILURE CAUSES OF DISCONNECTORS AND EARTHING SWITCHES

First survey on reliability of Disconnectors and Earthing switches (DES) was based on the review of responses from a total of 21 countries that participated both in gas insulated and in air insulated substations (GIS and AIS) surveys of almost a quarter million disconnectors and ES [55].

Six different types of disconnectors have been reviewed: center-break, double-break, knee-type, vertical break, semi-pantograph, and pantograph disconnectors [53]. It was found that most MFs occurred with center-break-type DES (43%), 21% of MFs happened with double-break DES, and knee-type and vertical break DES together had 10% of all MFs (3% and 7%, respectively). Low-speed ES had 18% MFs, while high-speed switches experienced no failures.

Failure cases have been sorted by type of substation. It was found that MFs of DES happened more often at AIS (more than 60%) than at GIS (20% at one-phase GIS and 32% at three-phase GIS) compared with minor failures of the switches. Most cases of DES MFs were found with the electric motor operating mechanism (55%), compared with 39% with the pneumatic operating mechanism and 6% with the manual one. The important factor in DES MFs was determined to be the service condition in which the failure happens. Most failures occurred during “normal service operation demanded” (61%), much less during “normal service—no operation” (24%), and 8% of all MFs happened in the de-energized condition.

6.5 FAILURE CASES OF HIGH-VOLTAGE ELECTRICAL EQUIPMENT

In this section several failure cases of different types of HV electrical equipment will be presented as they have been described in original papers and reports. These cases have been selected because they represent those events when the equipment failure originated from the failure causes repeatedly mentioned by most industries utilizing electrical equipment (Section 6.3).

6.5.1 FAILURES OF HV BUSHINGS

An impressive account of HV bushings' failures is presented in IEEE PES “Progress Report on Failures of High Voltage Bushings with Draw Leads” [56]. The report states that the failure rate of 230 kV bushings increased significantly in 2007 with eight failures, an additional related failure in 2009, and two failures in 2010. Failed bushing age ranged between 4 and 13 years.

Bushing failure points in sealed-type transformer tanks are found below the flange for gas space transformers, with greatest damage in the lower insulator, in bushing tube and in the lead. For conservator-type tanks the failure point is typically above the flange for conservator transformers, which destroys the upper porcelain, leaving the lower insulator intact.

A detailed root cause investigation has been performed to reveal the cause(s) of multiple HV bushings failure. The evidence collected points to the arcing issue: arc marks confirmed by laboratory analysis, with the worst affect found in the dry portion of the bushing tube.

It was proved that noninsulated leads are able to flash over and make contact, and that random contact between the cable and the tube contributes to the problem as an unintended current path is formed. These facts led to a conclusion that the common cause of HV bushings' failure was *arcing* between the bushing tube and the draw lead cable, with the *flashovers* as the initial cause of failures.

6.5.2 FAILURES OF HV TRANSFORMERS

6.5.2.1 Case: Failure of Winding Insulation and Bushing

The case of a violent failure of an HV three-phase autotransformer (220, 132, and 11 kV, 50 MVA) at a substation in India in 2006 is presented in Ref. [57]. This transformer was in operation for 22 years since 1984 and failed with openings at welded joints on top of the tank. It was found that the lower part of R-phase of HV (220 kV) bushing had been damaged, with the cellulose insulation exposed, the upper part of the R-phase bushing had popped up. Y-phase and B-phase of HV (220 kV) bushings were found to be displaced from the bottom part. The gaskets were in a very bad condition and continuous oil leakage was found from the bottom of Y-phase of HV bushing. Both the inspection window and the main tank of the transformer were found lifted up from the welded joint portion under pressure and many other kinds of damage were also discovered. No previous failure or major repair of the transformer was reported.

Analysis of the failure showed that the transformer was quite old and was in operation for more than two decades. The average loading on the transformer has rarely exceeded 50% of its rated capacity and has never been overloaded beyond its maximum capacity during its service life. Even on the day of failure, loading on the transformer was only 18 MW. Therefore, the cellulose insulation of the transformer was most likely to have passed through the normal aging process, and fast aging due to overloading was not expected.

The oil condition according to the data of the test performed a year before the failure showed the measured parameters of oil within the desired limits. But the DGA conducted also during the previous year showed that the content of oxygen (O_2) was 6640 ppm, which is considered dangerous for the transformer. The concentration of oxygen might have increased further over a period of about 1 year until the date of failure in 2006.

Both the moisture and oxygen content of the insulation system have a decisive influence on the aging rate of the power transformer. Moisture, especially in the presence of oxygen, is extremely hazardous to transformer insulation. Oxygen together with a water content of 2% in paper insulation can raise the rate of aging by a factor of 20. Oxygen with concentration above 2000 ppm dissolved in transformer oil is very destructive for paper insulation. Additional moisture, especially in the presence of oxygen, is extremely hazardous to transformer insulation. This might have accelerated the aging process of paper insulation. Low-energy arcing and aged paper insulation might have resulted in insulation failure.

Arcing might have taken place inside the transformer due to either a failure of winding insulation/HV bushing and/or bad contact in the tap changer, which has resulted in the formation of gases and development of gas pressure. A continuous increase in content of oxygen and nitrogen and insulation failure might have led to the high-energy arcing, accumulation of other fault gases and rise in gas pressure.

High gas pressure development inside the transformer and nonoperational condition of the pressure relief device (PRD) possibly due to blockage have resulted in the creation of openings at vulnerable regions and weak points of the transformer tank and some welded junctions to vent out the gases. It was concluded that the failure of the transformer was caused by the *failure of winding insulation and bushing*.

6.5.3 FAILURE MECHANISMS OF HV TRANSFORMERS AND BUSHINGS

In several studies and surveys, it was found that problems with bushings are a major source of HV transformer failures. To develop a means of preventing violent, dangerous and costly failure events, it is important to clearly identify the possible failure mechanisms of HV bushing. Defects in a bushing may originate from one or more main parts of the bushing construction: core, core surface, oil, the porcelain inner surface and so on [5]. Core defects include ingress of moisture or air, or high losses of impregnated liquid, all of which might result from leaking or deteriorated gaskets. These defects may be residual moisture, poor impregnation of oil into paper, migration of conductive graphite ink used in some bushings instead of foils, shorted layers, oversteering, or dielectric heating. Wrinkles and delamination in papers may also cause defects.

- *Core Surface Defects* may arise from surface moisture, contamination from oil aging products, and deposits of metal or carbon particles on the surface. These deposits may give rise to PD on the core surface, reduced surface resistance, and increased dielectric losses. Failure modes resulting from core problems include ionization, gassing, thermal runaway, puncture, flashover, and explosion.
- *Aging Defects of the Bushing Oil* develop as the oil deteriorates from the effects of high temperature from core heating, moisture, electrical field, and bushing solid materials. The oil may be contaminated with colloid-type inclusions containing copper, aluminum, zinc, and so on, and lose its dielectric strength. Since the oil/paper ratio is small in the bushing, even small quantities of oil loss or moisture ingress from the atmosphere or core may significantly degrade the insulation qualities inside the bushing.
- *Aging of the Internal Porcelain Surface* may be caused by deposits of carbon, and semiconductive sediments from oil breakdown and even from particles of iron from pump bearing wear. Impurities in the porcelain may give rise to PD, and catastrophic failures from this mechanism have certainly been noted in epoxy bushing construction. Failure modes from oil and porcelain surface problems include PD, surface discharge, and gassing.
- *Conductor Defects* are caused by overheated connections at the top and bottom of the bushing and may be worsening by the use of dissimilar metals.

- *External Defects* such as cracks, contamination, and surface discharge may occur and result in a flashover. Improper storage of spare bushings has been known to promote failures. Problems with seals may also cause major defects from loss of oil or moisture ingress.
- *Bushing Failure Scenarios.* Faults in the bushing core [58] result in the development of destructive ionization at the points of overstressing, overheating, and thermal instability of dielectric materials. These processes create a defective area with excessive conductance appearing between two or more core layers, which results in a burning through between papers and the occurrence of a short circuit between two of the several layers. As core layers are shorted, this failure mechanism leads to further heating and finally to a state of thermal runaway: an explosion is practically inevitable from this condition. In another failure scenario occurring in an inner capacitive layer of the bushing, the overheating causes the paper to dry and then burn outward. As the paper burns, hydrocarbons are created that cause gases to be generated in the bushing. Eventually these gases build up pressure, resulting in explosion and fire.

6.5.4 FAILURES OF HV CBs

6.5.4.1 Case 1: Failure of Mechanical Linkage

The case was reported in Ref. [57] about an HV SF₆ CB failure that occurred at a substation in India in 2006. The interrupter chambers of the Y pole had exploded and porcelain housing had shattered into pieces. The root cause investigation found that the flashover of the insulator string of this phase at the tower location caused ground fault. The flashover had taken place on a normal day without any rain. The fault on the line initiated the tripping of the three-phase gang operated CB. During the opening of the CB, the R and B poles of the breaker successfully opened.

Unfortunately, the Y pole of the gang operated breaker failed to break the fault current. The fault current continued to flow through the Y pole of the CB for quite some time. The flow of high current through the breaker increased SF₆ gas pressure in the interrupting chamber, leading to blasting of the chamber to release excess gas pressure. The CB has served only for about 5 years. The visible holes on the metallic part of the main contact shows severe arcing marks.

The Y pole of the CB got disengaged from the gang/common operating rod connected to a common motor. The blasted Y pole of the breaker being disengaged from the common operating rod fell over the nearby isolator of the same bay, causing bus fault and outage of both 132 and 66 kV systems for about 31 min. It was concluded that the HV CB had failed due to failure of the mechanical linkage of the Y pole of the breaker with a common driving assembly while breaking the fault current.

6.5.4.2 Case 2: Trapped Water in Internal Bolt Holes

In April 2004 the failure of a 115 kV SF₆ gas CB was reported [59]. Although there was no visible external damage, relay and protection analyzed the relay information and all indications led to an internal failure of the K98 CB. After inspection of the disassembled breaker the flashover was noted at the bushing assembly, with evidence indicating that the arc struck from the bushing conductor to the bushing adapter

plate. The quantity of the arc by-product in the center phase tank was moderate, indicating that the flashover was not severe. Investigation into the cause of flashover indicated that randomly occurring water was the likely cause of the flashover. Water was detected using an ultrasonic inspection technique at different levels, in three of the six bushing nozzles, in bolt holes.

The manufacturer disclosed their knowledge of three other similar failures of the same type of breaker and admitted to a known process control that was identified and corrected in 2001, affecting breakers manufactured between 1999 and 2001. The manufacturing process began with pressure washing the cast breaker tanks with water. The tanks were set outside to dry, and the failure was attributed to trapped water in internal bolt holes. This water then eventually migrated into the tank, providing a point of discharge, ultimately faulting the breaker internally at the point of water droplets on the tank wall. The manufacturer did not issue a service advisory to all their customers notifying them of this problem.

6.5.4.3 Case 3: Contact Jamming or Mechanism Failure

This failure case of SF₆ CBs was reported by an electrical transmission and distribution company operating in Zambia [60]. In August 2008, a 66 kV SF₆ CB failed when the feeder, on which it is installed, was de-energized to allow a high load to pass under the line. This CB was less than 6 years old. The blue phase interrupting column completely shattered approximately 30 s after de-energizing the concerned transmission line. There was a flashover, resulting in the snapping of the conductor and catastrophic failure of the CB.

The consequences of the failure were extremely damaging. The flying porcelain debris from the CB damaged the post insulators for the 66 kV line isolator, the line main and reserve bus bar insulators and the conductors to transformer 66 kV main bus bar isolator. The flying porcelain debris from the CB also damaged insulator discs for the bus bar flyovers on two 66 kV line bays. In addition, the red phase VT on 66 kV line had oil leak and cracked porcelain from the flying debris. The blue phase VT on an adjacent line bay was also affected and had an oil leak. SF₆ CB interrupting columns and support insulators were completely shattered. The blue phase assembly components (fixed and moving contacts) were found on the ground. CB and line earth switch control cables were damaged as a result of the explosion. The explosion on the blue phase was vented in all directions and also downwards through the CB operating mechanism and control cabinet.

On the basis of a root cause investigation, it was suggested that the failure of SF₆ CBs could happen due to a lack of proper moving contact separation in the blue phase because of contact jamming or mechanism failure. The following scenario could explain how the failure had developed. At first, breaker contacts in the blue phase interrupting column did not open, or did not fully open; therefore, when an abnormal load was crossing the line, it made contact with the blue phase conductor, thus generating a fault current. The fault current generated in the blue phase, with the contacts not fully separated, led to arcing, heating, and decomposition of SF₆ gas in the CB blue phase column, which resulted in high pressure in the column and eventual explosion.

It has also been suggested that decomposition of SF₆ gas could play an important role in failure. SF₆ gas properties may have been compromised after arcing across

the contacts during fault clearing operations. Products of SF_6 gas decomposition include hydrogen fluoride, carbon tetra-fluoride and hydrolysable fluorides, all of which are corrosive in nature and can lead to loss of insulating properties and arcing across open CB contacts. These corrosive by-products can also degrade insulating materials that are present in the CB interrupting columns.

6.6 FAILURE CASES OF LOW- AND MEDIUM-VOLTAGE ELECTRICAL EQUIPMENT

6.6.1 BUSHING FAILURES IN MV SWITCHGEAR

Violent bushing failures in MV switchgear, if they happen, may cause catastrophic damage to the surrounding buildings and adjacent plants. A significant number of such catastrophic failures are presented in a report from the City of Cape Town in South Africa [61]. Multiple failures began occurring after the manufacturers replaced previously used Bakelite paper bushings with resin cast bushings. The replacement was related to the expansion of SF_6 and vacuum technology with the supposed advantages of resin cast technology. Resin cast insulators are considered have greater suitability for mass production, superior fault toleration, resistance to scratch and mechanical damage resistance. Some manufacturers would redesign existing breakers to SF_6 and resin cast technology to fit them in the same panel as the previous generation oil breaker. South African utilities used three models of SF_6 MV switchgear from the same manufacturer, which are all interchangeable with previous generation oil breakers.

However, contrary to the expectations, the City of Cape Town experience showed that bakelite paper bushings outperform resin cast bushings by far. A large number of bushing failures, mostly due to PD activity across the surface of bushings, were experienced on at least two models of the same panel and manufacturer, while severe PD activity but no catastrophic failures were experienced on a third model of the same manufacturer.

Some of the first recorded failures in the City of Cape Town were at the substation in 2004. Staff who entered the substation for switching operations experienced a strong smell of chlorine in the substation and, on further investigation, they found the breaker to be with severe discharge degradation on bushing insulation and cluster contacts [61]. Severe corrosion, tracking, and cluster degradation were also found at the substations (Figures 6.3 and 6.4).

During inspection, other defects have been found, such as pores beneath the skin of the bushing resin (manufacturing defects), as well as misalignment of shutter boxes (signs of poor-quality control during manufacturing).

Based on inspection results and root cause investigation, severe PD activity was determined as the primary cause of failures. The probability of PD activity was increased due to multiple local regions of electrical stress created within voids, pores, and bubbles in resin moldings.

Highly elevated humidity in the area where substations are located should be added to the failure causes. Humid air and, in particular, droplets of moisture accelerate PD activity in the bushing assembly. Moisture carried in air modifies the

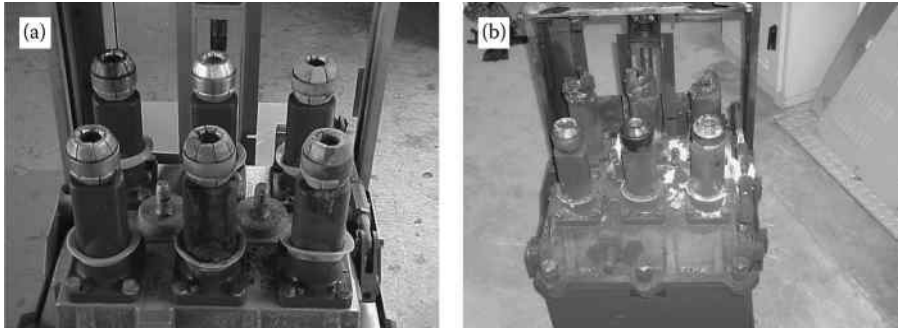


FIGURE 6.3 (See color insert.) Degradation of CB clusters and bushings. (From C. van Heerden and A. Rogerson. Bushing failures in medium voltage switchgear, 2009 AMEU Convention, Online. Available: <http://www.ameu.co.za>. With permission.)

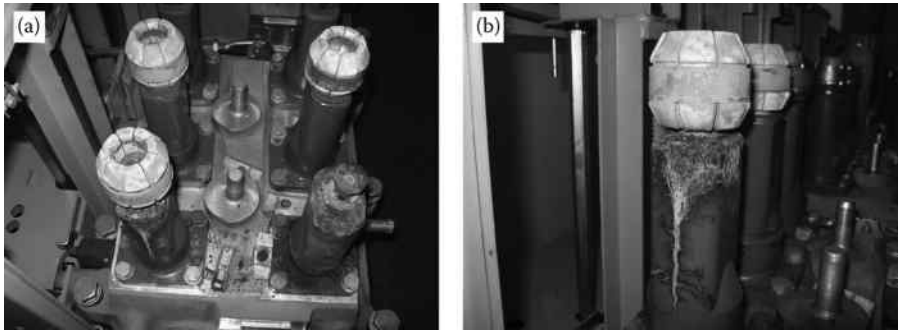


FIGURE 6.4 (See color insert.) Severe corrosion degradation of clusters (a) and tracking on the bushings (b). (From C. van Heerden and A. Rogerson. Bushing failures in medium voltage switchgear, 2009 Convention, Online. Available: <http://www.ameu.co.za>. With permission.)

dielectric properties of air, which in modern switchgear is a significant part of the insulation system. The reduced breakdown strength of the air increases the probability of PD. However, while most of the new switchgear panels are fitted with heaters, some manufacturers specify panel heaters as optional.

Misalignment of the breaker may play a significant role in increased PD activity. If the breaker bushings do not align with the respective orifice bushings, this results in an inconsistent electrical field around the bushing due to irregular positioning of the shutter box apertures. Misaligned shutter boxes may have the same effect. Misaligned breakers may also cause the orifice (female) bushing to be damaged and tracking may occur. These breakers may be dangerous to operate.

6.6.2 CASE STUDIES OF MV SWITCHGEAR FAILURES

The MV switchgear failures can be attributed to inadequate design. However, more often the failures could result from inadequacy of the maintenance practices, which fail to prevent and detect mechanical and electrical problems that lead to failures.

Increasing load densities also put a lot of pressure on the existing aging MV switchgear infrastructure. Solutions often try to accommodate the conflicting requirements of maintaining high reliability and availability while keeping the costs low and providing the highest levels of safety.

Given the space constraints in existing receiving stations, a feasible solution for enhancing the life of the existing switchgear is often resolved by retrofitting and refurbishment actions. However, refurbishment actions require providing operational flexibility and rating, and involve giving special attention to safety aspects and integration. Errors in design, defects of the components, and human mistakes, and a combination of all these, may cause severe MV switchgear failure [62].

6.6.2.1 Case 1: Component Defect

The following failure happened with a feeder breaker, which was taken out for performing condition monitoring tests. The wires for the timing test were connected to the breaker arms and the breaker was racked in the “test” position for performing the operations. The breaker flashed over while inserting in “test” position. It was found that flashover was caused by the failure of the mechanical interlock. The metallic clamp of the test equipment connected to the breaker came into arcing distance of the live bus bar, causing the flashover.

6.6.2.2 Case 2: Arcing, Design Errors

The MV breaker failed during fault clearance, causing extensive damage to doors and windows of the switchgear room. Root cause investigation led to the conclusion that during breaker failure the arc produced the pressure wave that could not find a way to escape and caused damage to the door and windows. This damage could be prevented if the outlets for the pressure wave have been installed at various locations in the switchgear room in the form of hinged louvers. These louvers remain closed normally and do not allow the outside dust to enter the room. In case a pressure wave is caused due to the electrical arc, the pressure is released through these louvers, thus preventing damage to the switchgear room and also injury to the operating personnel present in the room.

6.6.2.3 Case 3: Flashover, Water Condensation

A flashover occurred in the breaker compartment of a feeder which was charged and was carrying no current. It was found that the space heater in the breaker compartment was defective (manufacturing defect). The failure could have been avoided if it had been mandatory for the space heater to be in service even when the breaker carries a very low percentage of rated current (<30%). This would help avoid condensation in the breaker compartment. As the load current was zero in the case of failure and the heater was off, there was water condensation in the compartment, which resulted in flashover.

6.6.2.4 Case 4: Overheating

A medium voltage vacuum CB (22 kV, 2500 A) failed during service. On analysis of the failure, it was suspected that the current-carrying part of the breaker was getting overheated while carrying the nominal load current. The overheating was proved by

carrying out a Heat Run test, which showed that the TR was exceeding allowable limits. To prevent overheating with the breaker inside the cubicle, a de-rating factor of 20% had to be applied, especially for feeders that carry more than 70–75% of the breaker/switchgear rated current.

6.6.3 METAL-CLAD SWITCHGEAR FAILURES

Two failure cases of metal-clad switchgear are presented in NRC Notice 2002-01 [63], one at the U.S. Nuclear Generating Station (NGS) and another at a foreign nuclear power station (NPS). The most interesting aspect in both events was propagation of damage from an electrical fault in one breaker cubicle to other breakers and buswork in the same enclosure. These electrical events provide us insight into possible collateral damage and cascading failures resulting from a single electrical failure and the consequent challenges to plant operation.

6.6.3.1 Case 1: Failure of the 25-Year-Old Circuit Breaker, and Lack of Maintenance

While shifting loads to the unit auxiliary transformers, a fault on a 4.16 kV supply CB from the unit auxiliary transformer caused a fire and the loss of offsite power. The fault was caused by the failure of the 4.16 kV breaker's C phase main contacts to fully close. This resulted in arcing and the production of a thick, dark ionized smoke. The breaker was a three-pole, medium-voltage AC power CB rated for 3000 A (continuous) and 350 MVA (interrupting). The breaker was approximately 25 years old and had its last preventive maintenance performed four years prior to failure. Due to the extensive fire damage, the cause of the breaker's failure to close could not be definitively established.

Offsite power was lost when ionized smoke (which is conductive) diffused through holes (through which wires passed) and conduits between adjacent cubicles. This shorted the energized incoming terminals of the offsite power supply from the reserve auxiliary transformer. The fault blew open the cubicle door of the offsite supply CB and blew off an insulating boot that covered the A phase bus bar. The high-voltage supply breakers upstream of the reserve auxiliary transformer opened to clear the fault. This interrupted the nonvital offsite power to the unit. The loss of offsite power resulted in the need for dc backup power to operate the non-safety-related turbine lube oil pump. The failure of the DC supply breaker for the lube oil pump resulted in significant damage to the main turbine.

6.6.3.2 Case 2: Insulator Failure

At a foreign NPS, a fault in a 4.16 kV load center caused a fire and the loss of off-site power, while the reactor was shut down but with significant decay heat. This, combined with a subsequent independent failure in the onsite standby power supply, resulted in a station blackout (i.e., a loss of AC power to both redundant safety systems). Recovery from the event was further complicated by smoke and the dependence on ac-powered emergency lighting and ventilation.

For several days prior to the event, foggy, misty weather had caused salt deposition on the insulators on the 345 kV transmission system and consequent power fluctuations and interruptions. On the day prior to the failure, the 345 kV

transmission system had been interrupted, resulting in an automatic reactor shut-down and transfer to the backup 161 kV offsite source. On the day of failure, with the reactor shut down and with off-site power being supplied to the unit from the 161 kV backup source, the 345 kV source was recovered and the circuit into the plant was reenergized.

After the switchyard 345 kV CB was closed (energizing the 345/4.16 kV transformer and the 4.16 kV circuits into the vital load centers, while the 4.16 kV supply breakers were still open), a fault occurred in the A train 4.16 kV load center. The fault was caused by insulator failure on one phase of the A train 4.16 kV safety-related switchgear on the supply side of the supply breaker from the 345/4.16 kV transformer. The cause of the insulator failure is unknown. The fault produced voluminous smoke and ionized gas. Migration of the smoke through the A train 4.16 kV switchgear enclosure resulted in multiple arcing faults. Smoke from the event spread out, causing multiple failures in the switchgear, loss of both the sources of offsite power to both trains, and total loss of power to one safety train. An unrelated failure of the other source of onsite power led to total loss of power to both trains. In addition, the loss of offsite power disabled the backup station blackout power supply.

6.6.4 FAILURE OF MV POWER CABLES

There are several factors causing the failure of MV power cables [64]. The types of insulation of cables that are most widely used lately are PE (XLPE, TR-XLPE, and HMWPE) and EPR. Several causes of underground power cable failures have been defined [65,66], such as excessive pulling tension, water treeing, and corrosion. High-voltage surges may blow holes in the jacket and damage the shield, and water may enter through the holes and cause corrosion.

MV power cables are often located in inaccessible locations such as conduits, cable trenches and troughs, duct banks, underground vaults or in other directly buried installations; under such conditions, they can fail due to insulation degradation. Cable failures are one of the most important concerns for the nuclear industry, because the cables supply power to several loads at a nuclear power plant and the failure event may be very dangerous, causing loss of power to safety buses, service water and emergency service water [67]. An extensive account of cable failures can be found in the NRC report [68].

Very often, PD activity in power cables causes the failures. PD is accelerated by various defects, such as voids, shield protrusions, contaminants, advanced stage of water trees, and so on. Partial discharges will gradually degrade and erode the dielectric materials, eventually leading to the final breakdown [69].

6.6.5 LV SWITCHBOARD FAILURE

This switchboard failure occurred in a community infrastructure-related facility [70]. The damaged switchboard (Figure 6.5) had a supply bus rating of 2000 A, a section bus rating of 2000 A, and a neutral bus rating of 1000 A. The switchboard short circuit rating was 50,000 A. The system was three-phase, four-wire, 480/277 V. A physical



FIGURE 6.5 Failed LV switchboard. (From Ross B. *Anatomy of a Meltdown*, Electrical Construction and Maintenance, September 1, 2002, Online. Available: http://ecmweb.com/news/electric_anatomy_meltdown/. With permission.)

inspection covered the switchboard, the main breaker, the bus, the metering compartment, and another bus nearby. The arcing damage was found primarily in the main breaker cubicle, vertical bus, and the metering compartment above the breaker.

The examination revealed evidence of arcing (vaporized and missing metal) on the control wiring, on the load side vertical bus, on the line side vertical bus and cabinet metal, and on the main breaker finger clusters and stabs. Both the damaged and undamaged bus bars showed considerable corrosion and flaking. The inspection revealed corrosion within the failed breakers and their connections, as well as on the nearby breakers. It was found that hydrogen sulfide was present in the air of the breaker's electrical room. Over time, the hydrogen sulfide caused corrosion and flaking of the finger cluster surfaces. This gas also attacked the mating surfaces of the breaker cubicle bus connections (stabs), so they too corroded and flaked.

The following chain of events was suggested to cause the failure. About 20 days prior to the failure, electricians racked in the main breaker. Because the contact surfaces of its finger clusters and stabs were irregular and corroded, electrical connection had higher than normal electrical resistance. Load current passing through these connections produced extra heat, which accelerated further oxidation and deterioration of the connection surfaces. That, in turn, worsened the heating problem. The heating will likely be most intense on the center (B) phase, and it was enough to melt the B phase connection surfaces. The normal load current produced an arc that bridged across the small gap where the copper surfaces had melted.

Since the load current continued to flow through the arc, it melted and vaporized more of the contact surface material, producing extreme heat and ionized (conductive) gases. Intense heat and ionized gases entered the upper compartment and produced a short circuit of the 480 V (potential transformer) control wiring. Melted wiring insulation may have allowed separate phases to make contact, or the melted fuse block may have similarly allowed separate phases to make contact. The control wiring short

circuit was on the line side of the breaker and the line side of the control wiring fuses, and consequently did not cause the main breaker to open or the fuses to blow.

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7 Physical Conditions of Electrical Equipment

Testing, Monitoring, and Diagnostics

Equipment reliability might be significantly improved through the effective prediction of equipment degradation. To evaluate the degree to which an electrical machine has degraded, it is necessary that one is able to measure the values of the most important physical parameters characterizing a specific condition. For electrical apparatus there are multiple parameters that are directly related to the performance of the machine.

In this chapter, the main focus is on the physical conditions of the materials that the components of electrical equipment are made of. The electrical equipment include HV and MV electrical equipment, such as gas-insulated switchgear (GIS), HV CBs, power transformers and MV switchgear and CBs. Not discussed in this chapter are the monitoring and diagnostics of the multiple parameters related to operating conditions of such equipment.

The aging of different materials, both conductive and insulating ones, is a major part of the degradation mechanism of electrical apparatus. For example, conduction problems caused by loose connections or deterioration of contact surfaces result in a local temperature rise (TR), which contributes to a reduction of contact quality. Thermal runaways induced by conduction problems deteriorate insulating material and cause disruptive dielectric discharges, resulting in arcing faults. The consequences of such faults are serious enough to justify the efforts to develop and build condition monitoring systems to protect electric facilities from disaster.

In this chapter we discuss which physical conditions of the materials are most definitive in providing proper working conditions for different electrical machines and their important parts, and therefore are very important to evaluate. Multiple techniques are developed to measure various physical parameters offline, online, and remotely. Since some physical conditions may be determined only by offline testing, a number of testing techniques are discussed.

Various condition monitoring technologies allow condition monitoring of energized equipment continuously (online monitoring). These relatively new techniques give operation and maintenance personnel the means to evaluate the present condition of the equipment, to timely detect abnormal conditions, and to initiate actions for preventing possible forced outages.

7.1 PARAMETERS DEFINING THE PHYSICAL CONDITIONS OF ELECTRICAL EQUIPMENT

The aging of the materials that electric machines are made of is a continuous degradation process that occurs during normal service conditions and depends on the time in service and exposure to various environments. With time of equipment in service increasing, all electrical connections and insulations undergo aging and start losing their designed function. Monitoring and controlling the physical conditions of the components is an essential part of timely evaluation of their performance and making decisions to take appropriate actions for preventing an upcoming failure.

For example, among the many measurable physical conditions of current-carrying parts, the most important are: temperature, resistance, and contact load [1]. The list of important parameters can be derived from the well-known failure causes of a specific types of equipment (Chapter 6).

7.1.1 TRANSFORMERS

The major causes of oil-filled transformer failures related to materials are: insulation and bushing deterioration, loss of winding clamping overheating, decomposition of winding insulation, oxygen, moisture, and gases in the oil, oil contamination, and PD activity. This would mean that the important physical parameters for the monitoring and control of transformers are: the temperature of electrical contacts, bushings, and windings, the oil temperature and composition, and the presence of PD.

7.1.2 HV BUSHINGS

Bushings are strategically important components for the transmission of electrical energy. They are exposed to high thermal and electrical stresses. Monitoring and controlling basic quantities such as the oil level, pressure, and temperature of bushings, as well as detecting the corona and PD activity, is very important in order to identify dangerous conditions and to prevent thermal runaways.

7.1.3 CIRCUIT BREAKERS

The choice of parameters to monitor depends on the technology, rating, and application, as well as on the applied insulation media (vacuum, air, SF₆, or oil). Some of the physical conditions are usually measured during scheduled maintenance tests, such as the CR, voltage withstand of insulation, vacuum interrupter conditions, and so on. Many other conditions may be monitored online, when CBs are energized, such as the contact and conductor temperature, presence of PD, audible noise, SF₆ gas level, and so on.

7.1.4 SWITCHGEAR

Because switchgear distributes electrical current, heat buildup becomes a very important characteristic to monitor. The most significant amount of heat dissipation

TABLE 7.1
Parameters to Test and Monitor for Physical Condition Evaluation

Equipment Type	Temperature	PD	Corona	Oil Temperature, Composition	SF ₆ Level, Composition	Water
Transformer	X	X		X		
Bushing	X	X	X	X		
Switchgear	X					
Circuit breaker	X	X		X	X	
Cables	X	X			X	X
Transmission lines	X	X	X			

is on distribution elements such as bus bars. As bus bars are not made of a single piece of copper, the hot spots usually appear on connectors (used to attach breakers to the installation) or joints, which normally connect bus bars and output cables.

Electrical switchgear is dedicated to operating under some maximum load (maximum current flowing through distribution components). The distribution elements, switching elements, and bus-bar joints may reach a predefined maximum temperature under maximum load to keep the system safe [2]. Unexpected TR at a particular location could indicate corrosion or some other type of defect. If left uncorrected, this defect could result in catastrophic failure, resulting in deactivated loads and potentially hazardous conditions to personnel. Therefore, for switchgear, one of the most important physical conditions to monitor and control is the temperature of the distribution elements.

7.1.5 POWER CABLES

Several important factors characterize the degree of deterioration of a power cable: the temperature of the cable, presence of PD in polymer-insulated power cables or their accessories, water penetration under the cable shield, leakage in oil-insulated power cables, as well as SF₆ leakage in power cable systems.

Testing, monitoring, and controlling these factors (PD, detection of water in the cable, axial distribution of the cable temperature, etc.) would help to identify and prevent water treeing and cable shield corrosion and provide recognition, localization, and prevention of premature deterioration of power cable accessories. For transmission overhead lines it is important to also monitor corona, which might damage the integrity of the cable and insulators. The parameters recommended to be tested and monitored in various electrical equipment for the evaluation of physical conditions of electrical equipment are presented in Table 7.1.

7.2 TECHNIQUES FOR TESTING PHYSICAL CONDITIONS OF MV CABLES

Power cables are expected to remain a reliable conductor of electrical power for 30–40 years. It is therefore vital that the correct test procedures are followed and that

these cables are correctly installed, diagnosed, and maintained. It is important to analyze and compare different modern techniques of MV cables testing with regard to the application, type of cable insulation and accessories, and type of defect to determine. It is important to determine whether it should be online or offline testing and what should be the level of testing simplicity and cost.

It is predictable that the evaluation of different techniques by professionals from the companies providing cable testing would not be entirely objective and could often be biased toward a specific method. There are also opposing opinions among users of various techniques of proof testing. Some utilities providing routine testing on regular base are servicing the customers with increased reliability. However, many utilities continue to experience multiple failures caused by insulation degradation, which is accelerated by excessive proof testing overstressing the cables [3–5].

However, although the data presented in available publications may be affected by the subjective nature of the reviewed material, comparative analysis may still be helpful in determining the test method best suited for the required application.

7.2.1 COMPARISON OF MV CABLE TESTING TECHNIQUES

The most often used techniques for testing MV cables are the high potential withstand (HIPOT) test and PD diagnostics [6].

There are several benefits from using HIPOT to test MV cables. The test requires simple and relatively inexpensive equipment; it uses very simple procedures, and does not require a trained analyst to interpret the results.

On the other hand, HIPOT does not monitor the effect of the test on the cable during the voltage application; it relies on “pass or fail” result, thus exposing the cable to the damaging condition. The test also cannot register certain types of defects. This test also weakens all defects simultaneously, but fails only one at a time.

PD diagnostics are not only the most effective testing methods but also the most sophisticated techniques. Three types of PD diagnostic have been developed: (1) online PD testing, (2) offline PD testing, and (3) online PD monitoring. Continuous online PD monitoring technology for cables, although promising, requires further development to make it more affordable for industrial users. PD diagnostics are the only cable tests that can locate defects in shielded power cables. PD diagnostic testing has many strengths: it is a nondestructive test and the only testing technology that can detect and locate high-impedance defects such as void, cuts, electrical trees, and tracking. The test can be performed online in limited applications and is effective at locating defects in mixed dielectric systems.

The downside of PD diagnostics is that it is limited to cables with a continuous neutral shield. It requires a trained analyst to interpret measurements. This test cannot detect or locate conduction-type defects, and it becomes complex and time-consuming and loses accuracy in branched network applications.

The third category of cable tests is *General Condition Assessment (GCA)*, which includes multiple cable diagnostic methods and technologies, all of which determine the overall health of the cable insulation. These tests are quite sophisticated diagnostic tools, which measure the following factors: discharge dissipation factor (DDF)/tangent delta/power factor at 50/60 Hz and at 0.1 Hz—very

low frequency (VLF) technique; time and frequency domains (dielectric spectroscopy); return voltage/recovery voltage (depolarization current test); relaxation current (isothermal relaxation current method); measurement of leakage current and total harmonic distortion [6].

GCA diagnostic tests are considered to be nondestructive, because most tests are conducted at modest voltage levels with a short dwell time. These tests monitor the overall condition of the cable insulation and are effective in detecting and assessing conduction-type defects. Importantly, these tests provide information in the form of three categories—critically aged, moderately aged, and like new.

One disadvantage of GCA diagnostic tests is that they do not provide defect location, which results in complete cable replacement if the “bad” condition is found. The most important downside of these techniques is that the tests are not very accurate, and the results are highly temperature-dependent in extruded cables. The tests are blind to high-impedance defects such as cuts, voids, and PD with less than 10,000 pC. The negative economic side is that these tests require pretty costly equipment when compared to HIPOT equipment.

Different testing techniques are compared in Ref. [7] with regard to which test method may be preferable in detecting specific defects in both extruded (cross-linked PE (XLPE) and EPR) and laminated (PILC) cables, terminations, and joints.

7.2.2 HIGH POTENTIAL WITHSTAND TEST

HIPOT withstand test can be divided by voltage source into three types: (1) direct current (DC); (2) very low frequency (VLF), and (3) power frequency (PF). Each type of HIPOT test has its advantages and weaknesses.

7.2.2.1 DC HIPOT Test

A traditional method to test an MV cable has been to use DC high potential (HP), also known in the industry as DC HIPOT testing. For many years, this test worked well as a factory, field maintenance and assessment test. However, by the mid-1990s, multiple reports and field data made it evident that DC HIPOT testing could cause damage or prematurely cause the failure of extruded cables, especially field aged XLPE insulated cables.

This observation prompted the EPRI to fund two individual studies relating to the effect of DC HIPOT testing on XLPE and EPR insulated cables. The results were not conclusive on the EPR insulated cable; however, they were definitive on the XLPE insulated cable [8]. It was found that DC HIPOT testing before energizing a new MV cable does not cause any harm to the cable. However, when applied to an XLPE insulated cable that is in service and aged in a wet environment, DC HIPOT testing, using the industry-recommended DC levels and for the recommended length of time (i.e., 25 kV on a 5 kV cable for 15 min), may cause the cable to fail after its return to service. The failure may not have occurred at that point in time if the cable has remained in service and has not been tested with a high DC voltage.

It was also determined that DC HIPOT testing applied at recommended voltage levels cannot detect massive insulation defects in an extruded dielectric insulation cable. Also, applying over-voltage DC to a cable is done to take a snapshot of the

cable condition at a given time to determine whether it is a “go” or “no go.” It provides no trend data, life expectancy or condition assessment of the cable.

The latest publications also show that there is nearly unanimous worldwide consensus that DC HIPOT testing is not only damaging to solid dielectric cable insulation, but also an ineffective means of determining the insulation quality of a cable.

In North America, the IEEE, EPRI, Insulated Cable Engineers Association (ICEA), and others have denounced DC HIPOT testing for years, with the IEEE having written a new test standard for VLF that is promised to be implemented soon. European standards have been in place for years for VLF cable testing.

High-potential DC testing of XLPE MV cables is admitted to be a good installation check. It is also used for XLPE cables that have been subjected to long periods of exposure to moisture and in which water treeing may exist. Although the test is applicable to the cables in a wet environment, there are some concerns, as confirmed by EPRI studies. Three major industry associations are conservative about DC testing. IEEE, the Association of Edison Illuminating Companies (AEIC), and ICEA all have standards that address DC field testing of MV cables. The three groups are in close agreement about test values for installation tests, but after installation, however, all three reduce the testing stress and add cautions about wet environments.

IEEE-400-2001 Standard, “Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems,” describes the maintenance testing of up to 15 min, but also points out that DC HIPOT testing may be detrimental to XLPE cables in a wet environment in which water treeing may exist. AEIC CS5-94, “Specifications for Cross-Linked Polyethylene Insulated Shielded Power Cables Rated Through 46 kV,” describes an after-installation test for the first 5 years, but adds the statement, “After that time, DC testing is not recommended.” ICEA S-66-524, “Cross-Linked Polyethylene Insulated Wire & Cable for Transmission and Distribution,” says, “If voltage tests are made after installation, they shall be made immediately” and it makes no mention of maintenance testing. A new ICEA S-94-649, “Standard for Concentric Neutral Cables Rated 5 through 46 kV,” focused on concentric neutral design specifies maintenance testing limited to 5 min.

7.2.2.2 Very Low-Frequency HIPOT Test

VLF is generally considered to be run at the frequency 0.1 Hz and lower. According to IEEE Standard 400.2, “IEEE Guide for Field Testing of Shielded Power Cable Systems Using Very Low Frequency (VLF),” the main application of VLF HIPOT is in testing solid dielectric cables, installation quality and accessories, such as splices. The VLF HIPOT test is provided from 25 kV up to 200 kV, and load ratings are available from 0.4 to 50 μF , representing approximately up to 40 miles of 15 kV cable [9].

VLF HIPOT has the advantage of low energy requirements, 1/600 for 60 Hz voltages and 1/500 for 50 Hz voltages, which results in much smaller test sets than those required for normal operating frequency measurements. VLF PD detection can find major defects in cable accessories [8]. VLF has been more effective than DC in causing fault breakdowns on certain 15 kV, paper-insulated, lead-covered systems and on the 5 kV rubber and lead (R&L) cable that is used on service and main circuit taps [10].

It is considered as a good HIPOT test for conductive-type defects and high-impedance defects, which use a portable source with relatively low power requirement. The test lessens the aggravation of defects, because it does not induce as much space charge as DC HIPOT. It works well in aged extruded cables. Although it causes some defects, they grow rapidly, resulting in a shorter test time. However, the VLF HIPOT test has been demonstrated to aggravate defects in aged cable without failing, and therefore is not recommended for aged cables with multiple defects. The test does not replicate service conditions, cannot be directly compared to factory tests and does not replicate the normal stress distribution in insulation with wet regions.

7.2.2.3 AC Power Frequency HIPOT

There are no widely accepted test standards for AC HIPOT testing of cables, and PF AC HIPOT testing of cable systems is rarely performed. This is primarily due to the availability of other test methods and the high levels of power consumption and the large, heavy units required for AC HIPOT testing. However, this testing technique is good for conductive and high-impedance defects, it does not induce space charge, which minimizes the aggravation of defects in aged extruded cables, and it replicates steady-state service conditions and factory HIPOT tests.

7.2.3 PD DIAGNOSTICS

PDs are indications of a degrading insulation capability, which eventually leads to cost-intensive repairs and can result in electrical breakdown of the HV apparatus (see Section 5.2).

PDs are mainly caused by natural circumstances or by accelerated aging of the MV and HV insulation. Manufacturing or installation failures also can lead to harmful PDs. The goal of PD measurements is to detect the PDs at an early stage and to evaluate them in a proper way. Thus, periodic as well as continuous PD measurements have become one of the main means of assessing the quality and condition of HV equipment such as transformers, generators, switchgears, and cable systems. PD diagnostic tests could be performed online and offline, and they are the only cable tests, which can locate defects in the shielded power cable. There are several methods to provide online PD monitoring, which will be discussed in Section 7.4.1.

Online PD diagnostics can be performed without switching the circuit out of service; the technique can detect and locate some accessory defects and a few cable defects. It does not require an external voltage source. Online PD diagnostic tests are useful where there is no way to take the cable system out of service. They are useful in detecting some defects of cable accessories (joints and terminations), especially in short cables where the PD signals are not greatly attenuated. However, this method has many weaknesses since it detects only 3% or less of the cable insulation defects in an extruded cable. It is not a calibrated test; therefore, the test results are not objective. The online diagnostic test cannot be compared to factory tests or IEEE standards; it requires access to the cable every few hundred feet depending on the cable construction. The major downside is that it requires that manholes be pumped to access the cable and cannot be applied to long directly buried cables. These days it is only offered as a service and equipment cannot be purchased.

Offline PD diagnostics requires that the cable be switched out of service for tests to be performed, and the testing equipment is expensive when compared to HIPOT equipment. The equipment for offline PD diagnostics can be purchased and used by utility personnel and it provides onsite report of the test results. The test can indirectly locate large water trees associated with electrical trees. The test locates all defect sites in one test from one end of the cable. This PD diagnostic technique has been proven to be highly accurate by statistically significant correlation studies (83–95%). Offline PD diagnostics detects and locates defects in the cable system during voltage application. It is effective with mixed dielectric cables and can test up to 1 – 3 miles of cable depending on the cable construction. The offline PD diagnostics replicates calibrated factory baseline tests and can be readily compared as well, as it replicates steady state and transient operating conditions.

7.2.4 CHOICE OF MV CABLE DIAGNOSTICS

In 2002, the IEEE took major steps for revising its “Guide for Field Testing and Evaluation of the Insulation of Shielded Medium Voltage Power Cable” (IEEE 400–2001). This guide lists the various field test methods that are currently available or under development to perform field tests on insulated, shielded power cable systems rated 5 kV through 500 kV, including a summary of the advantages and disadvantages of the methods. The Guide includes six new approved testing methods: direct voltage, power frequency, PD, very low frequency (0.1–1.0 Hz), dissipation factor, and oscillating wave. Some of these tests are able to look at the condition of the insulation but cannot locate problems; that is, they are general health tests. Other tests are “partial discharge locator,” which can locate PDs that are a sign of incipient faults in the cable. Offline PD diagnostic testing is considered by IEEE Standard 400 as the most effective test for measuring PDs.

It is important to note that among all these tests, only the PD test can be performed while the cable remains energized and in service, making it the least disruptive test. It recommends that users review technical papers that are included as references and in the bibliography before deciding on whether to perform a test and which test to utilize. In making such decisions, consideration should be given to the performance of the entire cable system, including joints, terminations, and associated equipment. In many cases, this can be the determining factor for deciding on which test to use.

These new test methods have only been developed over the last 5–15 years, which makes them new to the industry and in some cases subject to the interpretation of the test engineer. Even though new tests exist, there is still not an industry standard test for the condition assessment of cable insulation, and none of the tests mentioned above are a clear leader in determining everything the user might want to know about the insulation or remaining life of a cable.

There is no simple recipe as to which technique is preferable for testing MV cables and accessories. To choose a proper testing technique, there is a set of things that need be considered: (1) the type of cable being tested; (2) age of the cable; (3) the type of defect you are looking for, (4) the environment; and (5) the risk tolerance level. Answers to these questions analyzed together with the strengths and weaknesses of each technique will allow one to make a reliable choice.

7.3 TESTING TECHNIQUES TO ASSESS INSULATION CONDITIONS OF HV/MV SWITCHGEAR, CBs, AND TRANSFORMERS

7.3.1 INSULATION CONDITION: PD TESTING

PD activity has long been accepted as a major cause of failure of HV/MV switchgear. PD is an electrical discharge or spark that bridges a portion of the insulation between two conducting electrodes. The discharge can occur at any location within the insulation system where the electric field strength exceeds the breakdown strength of that portion of the insulating material. Discharge can occur in voids within solid insulation, across the surface of insulating material due to contaminants, moisture or defects, within gas bubbles in liquid insulation. Discharges known as corona occur around the energized parts in a gas (see Section 5.2).

7.3.1.1 PD Mechanism and Effect on Insulation

PD mechanisms can differ depending on how and where the sparking occurs. In poorly cast resin CTs, VTs, and epoxy spacers, there are many defects such as voids and cavities filled with air. Since air has lower permittivity than insulation material, an enhanced electric field forces the voids to flashover, causing PD. Energy dissipated during repetitive PD carbonizes and weakens the insulation.

Contaminants or moisture on the insulation induces the electrical tracking or surface PD. Continuous tracking will grow into a complete surface flashover. Corona discharge from the sharp edge of an HV conductor is another type of PD. During PDs, ozone and nitrous oxides are produced, which aggressively attack insulation and also facilitate flashover during periods of overvoltage.

When PD activity occurs, it emits electromagnetic energy in the form of radio waves, light or heat. PDs also produce acoustic waves in audio or ultrasonic frequencies.

PDs may take place on any kind of insulation used in switchgear, including gas, liquid, and solid materials during a temporary over-voltage, during an HV test, or under transient voltage conditions during operation [11,12]. PDs occur in aged, defective, or poor-quality insulation and can propagate and develop until the insulation is unable to withstand the electrical stress and flashover and failure happens.

In HV/MV insulation PD takes place in two forms, surface PD and internal PD. When surface PD is present, tracking occurs across the surface of the insulation. In the presence of airborne contamination and moisture, the insulation is eroding. Internal PD occurs within the bulk of insulation materials and is caused by age, poor materials or poor-quality manufacturing processes. If allowed to continue unchecked, either mechanism will lead to failure of the insulation system under normal working stress, potentially resulting in catastrophic failure of the equipment (see Chapter 6).

PD testing in the field has been performed routinely overseas throughout Europe for many years, and its popularity is growing very quickly in the United States. PD testing has proven to be a very valuable online prediction tool to reduce the failures of MV and HV equipment. Depending on the apparatus that is being evaluated, PD can be detected using electro-magnetic, acoustic emission or capacitive sensors to measure the resultant radio frequency signals created by the minute “sparking” that occurs due to PD in the insulation.

According to IEC 60270, “High-Voltage Test Techniques—Partial Discharge Measurements” [13], traditional techniques for the detection of PDs involve taking a plant out of service and energizing using a discharge-free power supply and measuring signals using coupling capacitors and conventional PD detectors. However, very often, owners and operators of electricity distribution networks prefer to use handheld nonintrusive PD detection instruments for the purposes of both condition assessment and enhancing operator safety [14]. Where the cost can be justified, the use of more permanent monitoring options for critical and targeted switchboards is expanding. Many additional monitoring solutions are introduced into the market [15].

7.3.1.2 Ultrasonic Detection of PD

One of the most proper methods for PD detection of surface discharges, which usually have low amplitude, is the method that uses ultrasonic detection. Unlike surface discharges, internal void discharges have consistently high amplitude levels but have much lower discharge rates.

There are two basic types of online solid insulation PD testing equipment. One type is the hand-held ultrasonic emission detector, which is used to detect air-borne PD or corona in outdoor substations or inside switchgear. This device is useful and has led to the discovery of many electrical insulation problems.

However, there are many disadvantages with this testing. Airborne ultrasonic detectors are successful in detecting surface discharge activity where there is a good acoustic path, and it is an important tool for the detection of surface discharge within air-insulated switchgear. However, this technique is of little use on gas-insulated switchgear or on oil-filled transformers.

Since the sensor requires a clear air path to the problem source, it cannot look inside equipment or cables. The test equipment cannot distinguish the difference between corona (discharge into air), which may be relatively harmless, and PD, which is very destructive. In noisy environments such as HV substations or processing lines, this technology is often ineffective due to high background electrical or mechanical noise. Additionally, no true quantitative measurement of PD activity can be made using ultrasonic emission testing only.

7.3.1.3 PD Detection Using Transient Earth Voltages

The other type of online solid insulation testing equipment utilizes sophisticated measurement devices to detect, record, and measure PD. This type of equipment works extremely well to identify and quantify harmful PD activity. This equipment also detects PD within the insulation and does not require a clear line of sight to the defect. One of the most commonly used methods of detection of this type of internal discharge is through electromagnetic techniques and the detection of Transient Earth Voltages (TEV) in the 3–80 MHz frequency range [16].

Suppose that a PD occurs in the phase to earth insulation of an item of HV plant such as a metal-clad switchboard or a cable termination. During this discharge a small quantity of electrical charge is transferred capacitively from the HV conductor system to the earthed metal-cladding. The quantity of the transferred charge is very small and is normally measured in pico coulombs. The transfer occurs typically in a few nanoseconds. When PD occurs, electromagnetic waves propagate away from the

discharge site. Due to the skin effect, the transient voltages on the inside of the metalwork cannot be directly detected outside the switchgear. However, at an opening in the metal cladding such as the joints with the gaskets, the electromagnetic wave can propagate into free space and generate a TEV on the metal surface [12].

There are also relatively low-cost handheld instruments available that can detect both ultrasonic and TEV activity. Using this type of instrumentation as part of routine substation inspection can greatly enhance the condition information collected during this inspection and usually requires minimal additional cost or effort. The PD detection equipment may be applied not only to the most important switchboards' inspection but also to all MV switchgears on the network.

For internal PD problems, it was found that the level of TEV signals is proportional to the condition of insulation for switchgears of the same type and model, measured at the same point. This produced a very powerful comparative technique for noninvasively checking the condition of switches of the same type and manufacturer.

During several decades of PD testing, extensive information on substation PD survey results with over 15,000 entries covering different manufacturers, types of MV switchgear, and associated equipment have been collected [16].

After a large number of air-insulated switchgears with smaller dimensions were introduced into distribution networks, surface PD problems increased. Additional problems occurred when ceramic materials were replaced with polymeric materials for solid insulation in switchgear. Although polymeric materials generally offer good electrical insulation properties they are more prone to surface aging and degradation processes and any electrical activity on the surface of such materials eventually causes tracking damage.

7.3.2 DIAGNOSTICS OF OIL CONDITION

To diagnose the condition of oil-filled electrical apparatus, testing the physical conditions of oil provides the most valuable information. This information can be used to detect and identify early faults in apparatus, provide an indication of their severity, and identify long-term aging trends. Both load tap changers (LTCs) and bulk OCBs can fail mechanically, electrically, and from deterioration because of local overheating.

It was assumed that by-products of the deterioration and overheating could be found in the oil. In recent years dissolved gas-in-oil analysis and other insulating liquid tests have been used as effective tools to detect overheating problems in LTCs and OCBs. Specific guidelines and algorithms have been developed for evaluating the results from normal and abnormal LTCs and OCBs to help in the transformer condition assessment [17].

7.3.2.1 Dissolved Gases in Oil

For oil-filled transformers, the insulation system consists of oil and cellulose (paper). Under normal operating conditions, transformer insulation deteriorates and generates certain combustible and noncombustible gases. These gases are: H_2 , CH_4 , C_2H_2 , C_2H_4 , C_2H_6 , CO , and CO_2 . The main cause of gas formation in the transformer is

the heating of the paper and oil insulation due to electrical problems such as corona (low-energy phenomenon) and electric arc (high-energy phenomenon) inside the transformer. The detection, analysis, and identification of these gases can be very helpful in determining the condition of the transformer. Dissolved gas analysis is very helpful in the electrical industry for the detection of gases in oil.

Detailed information on the concentration of all gases present in oil and the value of total dissolved combustible gases (TDCG) is given in IEEE Standard C57-1041991, "IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers" [18]. In this standard, four status conditions are specified to classify risks for an oil-filled transformer. For each status an increasing gas-generating rate indicates a problem in the transformer oil, thus requiring the need to check the gas level in the oil more frequently.

For example, when the measured TDCG level is less than 720 ppm (Condition 1), it represents normal aging of the oil and oil analysis needs to be done in 6 months.

When the TDCG level is found to be higher than 720 ppm but not exceeding 1920 ppm (Condition 2), it indicates decomposition and excess oil aging, which requires oil analysis every 3 months.

Further growth of TDCG up to 4630 ppm indicates excessive decomposition, which requires oil analysis every month (Condition 3).

The highest level of oil decomposition is when TDCG is found to be above 4630 ppm; it indicates excessive decomposition of cellulose insulation and/or oil (Condition 4).

Continued operation could result in failure of the transformer. If TDCG and individual gases are increasing significantly (>30 ppm/day), the fault is active and the transformer should be de-energized when Condition 4 levels are reached.

A sudden increase in key gases and rate of gas production is more important in evaluating a transformer than the amount of gas. One exception is acetylene (C_2H_2). The generation of any amount of this gas above a few ppm indicates high-energy arcing. Trace amounts (a few ppm) can be generated by a very hot thermal fault ($500^\circ C$). A one-time arc caused by a nearby lightning strike or an HV surge can generate acetylene.

If C_2H_2 is found in the DGA, oil samples should be taken weekly to determine if additional acetylene is being generated. If no additional acetylene is found and the level is below the IEEE Condition 4, the transformer may continue in service. However, if acetylene continues to increase, the transformer has an active high-energy internal arc and should be taken out of service. Operating a transformer with an active high-energy arc is extremely hazardous and may result in catastrophic failure [19].

7.3.2.2 Water, Acids, and Furans in Oil

It is well known that moisture continues to be a major cause of problems in transformers and a limitation to their operation. The presence of *water* in oil is very harmful to both the oil and the solid paper insulation. It can be present in the oil in a dissolved form, as tiny droplets. Since paper is porous it absorbs water, which accelerates the insulation degradation process. Water affects the dielectric breakdown strength of the insulation, the temperature at which water vapor bubbles are formed, and the aging rate of the insulating materials.

In the extreme case, transformers can fail because of excessive water in the insulation. The dielectric breakdown strength of the paper insulation decreases substantially when its water content increases [20]. A more long-term problem is that excessive moisture accelerates the aging of the paper insulation, with the aging rate being directly proportional to the water content. For example, as the water content in the paper doubles, so does the aging rate of the paper.

IEEE Standard C57.106.2002 [21] specifies the limits of water content in the mineral insulating oil, according to various voltage levels. For example, the suggested limits for the continued use of service-aged insulating oil are as follows: in a transformer of voltage class below 69 kV, amount of water should not be higher than 35 ppm; for transformers of voltage class above 69 kV but below 230 kV, moisture content should not be higher than 20 ppm. In the latest edition of this Standard, the amount of water in oil is defined not only according to voltage class but also based on operating temperature (Table 7.2).

Water does not remain at the same concentration in insulations, but rather it is continuously migrating between the solid and liquid insulation. In order to understand the significance of the water-in-oil value, the operating temperature of the transformer at the time of sampling must be known. Most of the water in a transformer system resides in the solid insulation (paper and pressboard) and not in the oil.

As the temperature increases the water is forced from the paper into the oil. Although the amount of water in the paper will change relatively little, the concentration in the oil may change by an order of magnitude or more, depending upon the initial water content of the paper and the temperature increase [20].

Acids are formed in the transformer oil by the oxidation process, and are responsible for sludge and varnish formation. Transformer oils are oxidized under the influence of excessive temperature and oxygen, particularly in the presence of small metal particles. Metal particles act as catalysts in the formation of carboxylic acids, which results in an increase in acid number.

In the worst-case scenario, the oil canals become blocked and the transformer is not cooled well, which further aggravates oil breakdown. The presence of acids in oil causes corrosion, because acids interact with the metallic materials inside the transformer. Acidity of the oil is characterized by Acid Number or Neutralization

TABLE 7.2
Accepted Maximum Water Content in Oil

Temperature	Voltage Class		
	Up to 69 kV	From 69 to 230 kV	230 kV and Above
50°C	27 ppm	12 ppm	10 ppm
60°C	35 ppm	20 ppm	12 ppm
70°C	55 ppm	30 ppm	15 ppm

Source: Modified from IEEE Standard C57.106–2006 *Guide for Acceptance and Maintenance of Insulating Oil Equipment*. © IEEE.

Number, which is the amount of potassium hydroxide (KOH) in milligrams (mg) that it takes to neutralize the acid in 1 g of transformer oil.

The acidity of oil increases with the age of oil in service, and high acidity means that the oil is oxidized and/or contaminated. Furthermore, an increase in the acidity has a damaging effect on the cellulose paper. Oil degradation also produces charged by-products (acids and hydroperoxides), which reduce the insulating properties of the oil.

Furans. Furans are a family of organic compounds which are formed by degradation of paper insulation. Overheating, oxidation, and degradation by high moisture content contribute to the destruction of insulation and form furanic compounds. Changes in furans between DGA tests are more important than individual numbers. The same is true for dissolved gases. Transformers with greater than 250 parts per billion (ppb) should be investigated because paper insulation is being degraded. ASTM D5837-99(2005) "Standard Test Method for Furanic Compounds in Electrical Insulating Liquids by High-Performance Liquid Chromatography (HPLC)" defines technique for determining the amount of furans in transformer oil.

7.3.2.3 Power Factor of Transformer Oil

Power factor indicates the dielectric loss (leakage current) of the oil. This test may be done by the DGA laboratories. A high-power factor indicates deterioration and/or contamination by-products such as water, carbon, or other conducting particles; metal soaps caused by acids attacking transformer metals; and products of oxidation. The DGA labs normally test the power factor at 25°C and 100°C. The Doble Engineering Company, in its *Reference Book on Insulating Liquids and Gases* [22], indicates that the in-service limit for power factor is less than 0.5% at 25°C. If the power factor is greater than 0.5% and less than 1.0%, further investigation will be required. In this case the oil may require replacement or fuller's earth filtering. If the power factor is greater than 1.0% at 25°C, the oil may cause failure of the transformer; replacement or reclaiming will be required. Above 2%, the oil should be removed from service and reclaimed or replaced because equipment failure has a high probability to occur.

Doble Engineering Company has set up limits for other parameters of in-service oil, such as dielectric breakdown voltage, interfacial tension, water content, and neutralization number (content of acids in oil) [22]. The Doble limits for some parameters based on the recommendations of IEEE Standard C57.106-2006 are shown in [Table 7.3](#).

7.3.2.4 Techniques of Oil Diagnostics

Transformer oil sampling and analysis has been used for many decades to provide valuable information regarding both the condition of the dielectric and the electrical condition of the transformer itself. Because of the low cost of the analysis and the ease in which samples can be taken, oil sampling has become the most frequent test performed on transformers today. In recent years, progress has been made in the analysis of dielectric fluids contained in LTCs and OCBs. In transformers and CBs, the analysis reveals both the condition of the dielectric fluid and the equipment itself, such as abnormal contact wear. Oil sampling in these devices is being adopted nowadays into more and more maintenance programs.

TABLE 7.3
Limits for In-Service Oil

Parameter (Max Value)	ASTM Test Method	Voltage Class		
		Up to 69 kV	From 69 to 230 kV	230 kV and Above
Power factor at 25°C	Std D 924	0.5	0.5	0.5
Water content, ppm	Std D 1533	35	25	20
Acidity, mg KOH/g	Std D 974	0.2	0.15	0.15

Source: Modified from *Reference Book on Insulating Liquids and Gases (RBILG)*-391, Doble Engineering Company Publishing, Boston, MA, 1993; IEEE Standard C57.106–2006 *Guide for Acceptance and Maintenance of Insulating Oil Equipment*. © IEEE.

Dissolved gas analysis (DGA) is used to determine the concentrations of gases dissolved in the oil such as nitrogen, oxygen, carbon monoxide, carbon dioxide, hydrogen, methane, ethane, ethylene, and acetylene, according to ASTM D3612 [23]. The concentrations and relative ratios of these gases can be used to diagnose certain operational problems with the transformer, which may or may not be associated with a change in a physical or chemical property of the insulating oil. For example, high levels of carbon monoxide relative to the other gases may indicate thermal breakdown of cellulose paper, while high hydrogen, in conjunction with methane, may indicate a corona discharge within the transformer.

The detection of water in oil is most often performed in the laboratory by an analytical technique called the Karl Fischer titration described in ASTM Test Method D 1533 or IEC Method 60814. Both methods are very similar and are used to determine the amount of water in the oil sample on a weight-to-weight (mg/kg) basis or what is commonly known as ppm (parts per million). This method does not measure the water content in the paper insulation.

7.3.2.5 Online Monitoring of Transformer Oil Conditions

Equipment to continuously monitor oil condition in service is increasingly being installed on power transformers. The most widely installed systems measure hydrogen content. Systems for measuring other gases and moisture are also available. The hydrogen and composition sensors use semiconductor or fuel cell technology. There are more complex sensors that use infrared technology, gas chromatography, and photo acoustic spectroscopy. These systems can detect several or all dissolved gases in oil.

Several devices are available that provide for continuous online measurement of moisture and dissolved gases in oil [24]. In a simpler solution, the transmitter, which is compatible with any insulating oil, monitors the moisture levels at all ambient and operating conditions. The measurement can be connected to the substation data-collection system directly [25]. Other systems can simultaneously monitor moisture, and any number of dissolved gases depending on system complexity [26]. However, the most complex systems are also very expensive; thus few if any utilities can afford

them on all transformers, so the most sophisticated monitors are commonly found on only the most critical equipment.

There are many types of fairly simple and straightforward analyses that can be done online. However, the collected data can also be used for more complex analysis. This includes analysis of dissolved gas results and variations, even on monitors that detect a weighted sum of gases. Transformer loss of life and overload in real time may be calculated, as well as moisture in oil and moisture in paper at times when transformers are close to equilibrium of temperature and load.

Using online monitoring data allows comparing online condition monitoring results with offline results obtained via traditional methods. It allows to calculate the compensation of oil level for oil temperature; to measure transformer temperature rise (TR) above ambient; and to compare the results from transformers of similar design. The focus of this analysis is mainly on the oil/paper insulation systems of the transformer. Online monitoring data, taken together with known theory on equipment behavior, can be used to narrow down information on a transformer's condition to a few possible causes. This is one of the desired outcomes of analysis of data received by online monitoring systems.

7.4 ONLINE MONITORING TECHNIQUES FOR PD OF MV SUBSTATIONS, SWITCHGEAR, AND CABLES

Continuous online monitoring employs special technologies developed for PD detection. For the PD measurement, electrical, HF, UHF, acoustical, chemical, and optical techniques are in use. These techniques have been standardized in North America and Europe. For example, the international IEC Standard 60270, "High-Voltage Test Techniques—Partial Discharge Measurements," defines guidelines for conventional PD measurements.

These methods may provide the users with the benefits of early detection of deteriorating insulation components and auxiliaries. Online monitoring will guarantee a reduction of in-service failure rates, that is, reduction of un-scheduled and costly downtimes, help in the planning of preventive or condition-based maintenance.

There are several techniques developed for online continuous monitoring of PD activity of cables, switchgear, CBs, and other MV/HV electrical equipment.

In the simplest case a shunt resistor converts the PD impulse current to a voltage signal. The characteristic of the detector (quadrupole—RLC detection impedance) can be designed for integrating the PD signal to obtain the apparent charge of each discharge. The available measurement systems can detect the apparent charge and also the phase location according to the supply voltage. Furthermore, the number of discharges over a given time interval are recorded [27].

Optical PD detection is based on the detection of the light produced as a result of various ionization, excitation, and recombination processes during the discharge. The amount of emitted light and the wavelength depend on the insulation medium (gaseous, liquid, or solid) and different parameters (temperature, pressure, etc.). The optical spectrum of the emitted light of PDs is extended from the ultraviolet to the infrared range [28].

7.4.1 PD DETECTION IN SUBSTATIONS, SWITCHGEAR, AND CABLES

To monitor PD online in *substations* [29], the system is using a multisensor cable loop providing UHF (ultra-high frequency) PD detection, which is a sensitive, noncontact method. The single-loop UHF PD location system is applied to an array of *MV switchgear* units. Since all cable lengths are known, the time-difference-of-arrival between acquired signals can be used to locate the defect. The system can locate PD activity and arcing (intermittent or repetitive). The system can be applied to any MC equipment, not necessarily switchgear, and metal cladding is needed in order to avoid crosstalk between sensors. Another system combines TEV technology and ultrasonic detection (UltraTEV) [30] and is applicable for the continuous monitoring of PD activity in MV substations.

Another continuous online PD monitoring system has been developed for cable joints of *underground cable* circuits, which was based on the optical sensing technique using electro-optic (EO) modulators [31]. This proposed monitoring system does not require any power supply at the site of the cable joints, as the EO modulators are passive. Potentially, new cables could be laid together with optical fibers and new joints could be designed to include optical network ready PD sensors.

A cost-effective online PD detection and location system for *MV cable* circuits was investigated and the development of a commercial system, named PD-OL (Partial Discharge monitoring, Online with Location), was based on the following concept [32]. If a PD is occurring somewhere in a cable, which is a long homogeneous structure, it induces a voltage/current pulse with a duration in the order of magnitude of 1 ns. The cable is much longer than the wavelengths of a pulse; therefore, the cable is treated as a high-frequency transmission line to predict the behavior. The pulse travels along the cable in both directions. As it propagates through the cable its shape and amplitude will change due to attenuation and dispersion. At the end of the cable the pulse is detected by the measurement unit. The origin of the PD is determined by the difference in time of arrival of the PD pulse at each end of the cable.

The goal of PD location is to determine the physical location of a defect, allowing the utility to replace the defective component. Furthermore, if circuit data are available, the location gives the type of the component. Knowledge of the type of defective component improves the reliability of the interpretation of PD measurements to a large extent. The PD location accuracy must be sufficient to enable one to easily locate the physical location of the defect. A PD detection system locates the defect as a percentage of the total cable length. In order to convert this location to a physical location the exact cable length and cable route need to be known. Due to the frequency-dependent attenuation it is more convenient to specify the location accuracy relative to the cable length. A relative PD location accuracy is generally valid for a large range of cable lengths. Practical experience shows that a location accuracy of 1% of the cable length is both achievable during field measurements and acceptable for locating the physical defect location [33].

7.4.2 MONITORING PDs WITH FIBER-OPTIC TECHNOLOGY

Acoustic emission monitoring is often used in the diagnosis of electrical and mechanical incipient faults in HV apparatus. A large number of methods are available for

the condition monitoring and diagnosis of power transformer insulation, but only a few can take direct measurements inside a transformer. PDs are a major source of insulation failure in power transformers and their detection can be achieved through the associated acoustic emissions. Several studies [34–38] have reported the development of the sensors and systems that are able to monitor the presence of PD in transformers.

For example, the system in Ref. [36] is based on extrinsic and intrinsic fiber Fabry–Perot interferometers for the detection of incipient faults in oil-filled power transformers. The sensors can be placed inside the transformer tank without affecting the insulation integrity, improving fault detection and location. The performances of the sensing heads are characterized and compared with the situations where it operates in air, water and oil and promising results are obtained, which will allow the industrial development of practical solutions.

In Ref. [37] detection is based on optic phase changes in an intrinsic Mach–Zehnder fiber-optic interferometric sensor of high sensitivity. The sensor can be placed within transformers and is suitable for the detection of weak acoustic signals associated with the PD. The calibration of the interferometric fiber-optic acoustic sensor at typical frequencies displayed by PDs is presented.

In Ref. [38], a fiber-optic sensor based on a Fabry–Perot interferometry is constructed by a simple micromachining process compatible with microelectromechanical system (MEMS) technology. The sensors are used in a transformer to measure PD acoustic waves. The experimental results show that the sensor not only has an inherent high signal-to-noise capability, but is also able to accurately localize the PD sources inside the transformer.

Fiber-optic sensors are attractive devices for PD detection because of a number of inherent advantages including their small size and high sensitivity. They are electrically nonconductive and immune to electromagnetic interference. However, until now, not a single system is available on the market for industrial applications, although this technique, if developed further, might present a very precise and safe method of monitoring PD in oil-filled HV electrical equipment.

7.5 TESTING OF HV BUSHING CONDITIONS

The parameters that characterize physical conditions of HV bushings are power factor, RIV (radio-influence-voltage), and DC insulation resistance (IR). Measuring the moisture content of the oil or compound is also very important since about 90% of all preventable bushing failures are caused by moisture entering the bushing through leaky gaskets or other openings according to operating records [39]. A number of traditional tests have been developed to measure these conditions.

1. *Power-factor test.* The power-factor test is the most effective known field test procedure for the early detection of bushing contamination and deterioration [40]. This test also provides measurement of AC test current, which is directly proportional to bushing capacitance. Bushings may be tested by one or more of four methods depending upon the type of bushing and the power-factor test set available [39].

These methods are the GST (grounded specimen test), the hot-guard test, the UST (ungrounded-specimen test), and the hot-collar test. Large variations in temperature have a significant effect on power-factor readings in certain types of bushings. For comparison purposes, readings should be taken at the same temperature, or corrections should be applied before comparing readings taken at different temperatures.

Complete detailed instructions on the method of testing and test procedure are usually given in the appropriate power-factor test set instruction book. This test has a number of weaknesses. It is affected by temperature and humidity and cannot detect the early stages of PD effects [41].

2. *The radio influence voltage test.* The RIV test can provide detection of corona in resin-bonded, solid-core non-condenser bushings. Methods of measurement of RIV are described in NEMA Publication No. 107 [41]. Liquid-filled bushings generally have a low RIV value. A high RIV value on this type of bushings which cannot be reduced by cleaning the porcelain indicates that the level of filling liquid should be checked.
3. *The DC IR test.* The DC IR test generally cannot be relied on for detecting early contamination in bushings. When bushing deterioration can be detected by DC IR, it is generally at an advanced stage requiring immediate attention. A 2500-V IR meter may be used for an IR check, but a high reading should not be completely relied upon as indicating a good bushing. Any bushing testing less than 20,000 M Ω has questionable insulating value.
4. *Hot-wire test for moisture.* The plastic-type compound used in compound-filled bushings may absorb moisture if there are leaks through the shell or cap. Moisture content of as little as 0.15% in soft compounds can be detected by inserting a red-hot rod into the compound. If moisture is present, a crackling, sputtering, or hissing sound will be heard. If no moisture is present, the compound will melt quietly. Another test is to put some compound on a wire and melt it in the flame of a match. If moisture is present, there will be a sputtering sound and small sparks will be thrown out. In contrast, a dry compound will melt without disturbance.
5. *Testing oil for moisture.* Whenever the presence of moisture in the oil of an oil-filled bushing is suspected or found by a bushing power-factor test, the oil should be drained out and a sample of it tested by a dielectric or power-factor test. Since the quantity of oil in a bushing is small, the old oil should be discarded and new oil poured in. If moisture is found in the oil, the bushing should be dried out before returning to service.

7.6 THERMAL CONDITIONS OF ELECTRICAL EQUIPMENT AND TEMPERATURE MONITORING

Conduction problems in electrical systems are due to either loose connections or deterioration of contact surfaces. They result in a local TR, and the greater the current, the greater the rise, which contributes to further downgrading of the contact quality. This leads to thermal runaway, and when the temperature becomes excessive, the

heat deteriorates the insulating material. Very often, thermal runaway ends up causing disruptive dielectric discharges, which are a disaster for the electrical systems, such as MV CBs, switchgear, and substations.

Overheating is one of the major causes of the failures of transformers and bushings, underground and transmission cables, and other important electrical equipment. In other words, an ability to measure and control the temperature of distribution and transmission equipment contacts and insulation, solid or liquid, is one of the important tools for preventing any equipment's disruptive failure.

Since TR occurs when the current flows through the system, temperature measurement should be made when the equipment is energized, for example, online. It might be periodic or continuous. There are many approaches to measuring temperature, some of which will be described in this chapter.

7.6.1 TEMPERATURE MEASUREMENT USING THERMOGRAPHY

To date, the solution most commonly used to protect against conduction faults consists of periodically carrying out maintenance operations, which include temperature measurement. Typically, at the time of annual servicing, a complete thermal inspection is made of the electrical installation, during which the temperature of the connections is checked. The technique that is usually used for this purpose is infrared thermal analysis. It consists of periodically inspecting the installation by means of an infrared camera, with the aim of detecting thermal faults likely to reveal a conduction fault [42].

In order to have visual access to the conductors, it is necessary to modify electrical installations with the openings/viewing windows. Such openings may be made in the metal plates of MV cubicles, but this downgrades the degree of protection and hence the operating safety. It is possible to make some metal walls "transparent" for infrared (IR) emission by installing inspection windows made of material transparent to infrared rays (quartz), or the so-called IR Windows. Despite such conversions, there are still multiple points to which visual access is impossible.

In addition, the infrared measurement principle is not very accurate since it only allows the emissivity of the radiating bodies to be measured, and not the temperature. To detect a fault by means of infrared thermal analysis, several conditions must be met at the same time: it is necessary to have a substantial fault, a strong current to reveal it and an expert eye trained to detect differences in emissivity between phases.

The periodic nature of inspection is the main limiting factor with this practice. A fault which appears on the day after the yearly visit will only be detected a year later, but it will continue to degenerate and lead to thermal runaway in the meantime.

7.6.2 CONTINUOUS TEMPERATURE MEASUREMENT

There are several techniques that can be used for continuous temperature monitoring of energized electrical equipment.

7.6.2.1 IR Noncontact Temperature Sensors

The technique for continuously monitoring the temperature using infrared emission of heated surface is to measure the temperature with noncontact IR thermometers.

IR sensors are installed in the close vicinity of the target and send signals to a remote PC [43]. An optimal distance between the sensor and the target is determined by the size of the target (diameter, D) and the parameters of the sensor. For each particular type of IR sensor the ratio FOV (field of view) = X/D is a constant value, where X is the distance between the sensor and the target. The smaller the target area (D) is, the closer the sensor should be located to the target. The solution is relatively inexpensive, but there are several disadvantages. First, the sensor must be directed towards the observed component very precisely and in most cases there is no possibility to install such a system on assembled switchgear. Second, since the components whose temperature is measured are typically enclosed within an insulation boot in the switchgear, the temperature readout is not very precise. This condition contributes to the limits for the number of possible applications and targets of interest. Another downside of using IR noncontact sensors is the need to run the cables from each sensor to receiving units.

7.6.2.2 Electronic Temperature Sensors

Some MV cubicle monitoring systems are based on the use of electronic temperature sensors installed at critical points. This solution offers the advantage of continuous monitoring of the installation and detecting thermal faults very early. The problem is that each sensor must draw its energy from the mains current and transmit digital data via an infrared or optical fiber link. Such complexity leads to a high cost for each measurement point. Another problem with using electronic temperature sensors is that they require the installation of devices whose level of reliability and service life are incompatible with the associated switchgear and the function to be performed. A diagnosis system must be much more reliable than the equipment that it is monitoring, especially if, as is the case here, it is not maintainable without a shutdown of the substation.

7.6.3 FIBER-OPTIC TECHNOLOGY FOR TEMPERATURE MEASUREMENT

Various combinations of fiber-optic technology are in use for temperature measurement and offer solutions for a variety of tasks. In the environment of high field strengths, the usage of optical sensors or fiber-optic technologies offers the possibility to measure important values without any influence of electro-magnetic interference (EMI). Also the galvanic separation (isolation) is an advantage [44]. Alternative temperature measuring systems for temperature measurements inside the equipment use thermal sensors based on fiber-optic technologies. This complex method consists of fiber-optic temperature sensors installed in the apparatus. Different types of sensors and functional principle are in use in the electrical industry [45].

7.6.3.1 Optical Fiber Sensing Probe

One possibility is to measure the temperature at one point of the fiber. For example, the temperature measurement principle is based on an optical fiber sensing probe. In such a probe, a small portion of the fiber cladding is removed and replaced by a suitable “reference” liquid whose refractive index versus temperature characteristic is known [46]. Another technique involves an optical fiber with a temperature-sensitive

phosphor tip at the end. After excitation with blue-violet light the phosphor fluoresces with red light. The intensity of this light decays exponentially with time. The decay time is measured (the time constant of decay is inversely proportional to the sensor temperature) and correlated to the tip temperature [47].

Various combinations of fiber-optic technology come in many forms and offer solutions for a variety of applications. A fiber-optic sensing device is generally made up of two separate components, namely the amplifier unit and a sensing head assembly. The sensing head assembly comprises a pair of optical fibers, a transmitter and a receiver, terminating in the optical fiber-based head [48,49].

The probe requires no wires or other metal parts. It is electrically nonconducting, unlike thermocouples and resistive temperature detectors (RTD). Therefore, it can be installed in HV environments. Fiber-optic technologies are used for the temperature monitoring of cables and HV transformers.

A fiber-optic wire may be used as a temperature data carrier or as an active sensing element. In an active sensing element, temperature-dependent modification of the optical transmission properties is used in distributed fiber-optic temperature-sensing systems [50]. In other systems, a fiber-optic cable is used as a temperature data carrier, which delivers light to the sensing element installed at the measurement point. After passing through the sensor the signal is modified by the changing temperature in the sensing head. Then another fiber-optic cable carries back the modified signal to the analyzer. The materials in the fiber that communicate with the sensitive element exhibit low thermal conductivity as well as a narrow cross-sectional area. This minimizes heat flow to and from the active sensing element from outside the volume whose temperature is to be measured.

Fiber-optic temperature transducers are compact, immune to electromagnetic and radio-frequency interference (EMI/RFI), resistant to corrosive environments, and provide high accuracy and reliability in temperature measurements. The various combinations come in many forms and offer solutions for many applications. Sensitive elements at the fiber tip provide rapid and accurate temperature measurement. Mounting the sensing element at the end of a small optical fiber allows placing the sensor in difficult-to-access locations.

7.6.3.2 Distributed Fiber-Optic Temperature Sensing

Another possibility is to measure the temperature distributions along the length of the fiber-optic cable with the use of thermo optical effects. The light impulse injected into the fiber is subjected to scattering as it travels and the backscattered light impulse is returned to the detector. Among the returned light pulses, the intensity of Raman scattering is closely related to the temperature of the position of scattering. So the temperature along the fiber can be measured from the intensity of Raman scattering [51].

In the case of the existing power distribution system, applying the fiber-optic modifications to the equipment would require serious modifications with subsequent design verifications and testing. In the case of the draw-out MV CB, for example, it would necessitate designing a special automatic disconnect to comply with the requirements of the ANSI Standards. So the application of such a system, while very

reliable and relatively inexpensive for the new equipment, becomes prohibitive for the existing equipment.

7.6.4 WINDING TEMPERATURE MONITORING OF HV TRANSFORMERS WITH THE FIBER-OPTIC TECHNIQUE

The loading capability of power transformers is limited mainly by the temperature of the winding. As part of acceptance tests on new units, the TR test is intended to demonstrate that at full load and rated ambient temperature, the average winding temperature will not exceed the limits set by industry standards.

However, the temperature of the winding is not uniform and the real limiting factor is actually the hottest section of the winding commonly called the winding hot spot (WHS). The temperature of solid insulation is the main factor in transformer aging. When insulation is exposed to high temperature for extended periods of time, the cellulose insulation undergoes a depolymerization process during which the cellulose chains get shorter.

When it happens, the mechanical properties of paper such as tensile strength and elasticity degrade. Eventually the paper becomes brittle and is not capable of withstanding short-circuit forces and even normal vibrations that are a regular part of the transformer life. Such a condition of the paper indicates the end of life of the solid insulation. Since this condition of the paper insulation is not reversible, it also defines the end of life of the transformer.

Therefore, winding temperature is a prime concern for transformer operators. This variable needs to be known under any and all loading conditions, especially in the unusual condition involving rapid dynamic load changes. Accurate knowledge of the temperature of the winding hottest spot is a critical input for the calculation of the insulation aging, assessment of the risk of bubble evolution and short-term forecasting of the overload capability. It is also critical for efficient control of the cooling banks to ensure that they can be set in motion quickly when needed [52].

The WHS area is located somewhere toward the top of the transformer, and is not accessible for direct measurement with usual methods. For about 40 years, fiber-optic temperature sensors have been available for temperature measurement in HV transformers. The first units were fragile and needed delicate handling during manufacturing and installation. Over the past 20 years, significant development has taken place to improve ruggedness and facilitate connection of the five cables through the tank wall. New fiber-optic probes are protected with a permeable protective PTFE Teflon sheath to withstand manufacturing conditions including long-term immersion in transformer oil.

In one instance of temperature monitoring at Manitoba Hydro, fiber-optic sensors have been installed in more than dozen critical oil-filled HV transformers, each of these transformers containing eight probes to measure hot spots in the windings. Monitoring the winding hot-spot temperature together with measuring the dissolved gas-in-oil and furan-in-oil provides a major support to the operator when the transformer faces overload conditions. Online monitoring of winding temperature can provide a dynamic evaluation of insulation degradation [53,54].

There are several temperature-monitoring systems available on the market that are developed specifically for monitoring WHS in HV transformers.

7.6.5 WIRELESS TEMPERATURE MONITORING

7.6.5.1 Structure, Benefits, and Problems of Wireless Temperature-Monitoring Systems

The most troublesome issue in building a reliable condition monitoring system is wires that are used to get temperature readouts from the sensors. Elimination of wires required for constant communication with the sensor unit provides a great opportunity to build a temperature measurement system that (1) is easy installable, even on the already assembled switchgears, and (2) provides online temperature measurements.

The most important advantage of using wireless technique to monitor thermal condition of the energized equipment is eliminating any cables and wires from the online system. Another important benefit of wireless technology is much lower installation costs than that of any other type of online monitoring equipment [55–59]. Wireless systems should work well in difficult or dangerous-to-reach locations or in moving applications.

An ideal wireless temperature-monitoring system (WTMS) would consist of the specific components of hardware and software. Hardware consists of sensors and receivers or interrogators. To achieve the goal of wireless continuous temperature-monitoring of HV and MV energized electrical equipment, there are specific requirements to be met by the sensors. The sensors should be wireless units equipped with unique identification and should be made of miniature and dielectric components. Signal transmissions from multiple sensors should not interfere with each other. The sensing units should be installed at all strategically important points on the equipment, in locations with a very limited space. To make the system work uninterrupted during a long periods between maintenance, the sensing units should be equipped either with long-lasting local power source such as batteries or be self-powered by any available technique. For example, it could be the alternating magnetic field of an electrical conductor. Another possibility is that the sensor can be powered from a distance.

Receivers or interrogators should be installed at a significant distance from the sensors in the central location; they should collect the data from all sensors and transfer the data to a PC. They should work independently in series with other receivers. In case a temporary electromagnetic interference exists, they should easily recover.

Technology progress on wireless systems and devices introduces every year at least a few new wireless solutions so that there are several mature technologies that can be used to implement wireless sensor solutions. Unfortunately, because of the fact that often the wireless sensors are battery-powered, the lifetime of the sensor is limited to at most a few years. For critical applications, the average switchgear lifetime is about 30 years; thus the condition monitoring system should last for the same time and require little maintenance.

However, a major maintenance interval of MV and HV electrical equipment of 5–7 years is not uncommon. There are also solutions based on custom protocol

optimized for wireless temperature monitoring [60], but similarly to the standard sensors, the lifetime of the solution is limited by battery capacity.

7.6.5.2 Thermal Diagnostics

Thermal diagnostics has two separate goals. One is an ability to detect an early conduction fault (warning), another would be a thermal runaway detection, which results in forced interruption of electric current (protection). Conduction downgrading phenomena are generally slow and progressive. Early detection of conduction faults is based on an analysis of small changes in temperature. Detection of local overheating right from the start allows scheduling of maintenance operations at a convenient time, when it does not create a significant disturbance of the process.

Timely scheduled maintenance preserves the installation, mainly the contacts and insulating materials, since the thermal phenomena are still weak. A few principles may be used when developing the algorithms for early detection. For example, when monitoring the temperature in electrical switchgear, knowledge of cubicle thermal models is important. Correlation of contact temperature data with the current values and ambient temperature measurements, and temperature measured on all three phases may provide very important information on the thermal processes within the installation.

Since the overheating phenomena are usually rare and slow, the monitoring system should be designed to absolutely avoid false alarms, incorporating all available information on other network fault situations (strong phase unbalance, short circuit) or any temperature measurement fault (noise, incoherence). In the event of a conduction fault the alarming signal should contain the precise location of thermal fault in order to facilitate and shorten maintenance operations. In the event of a failure, it is necessary to set up a temperature-driven function which, when it observes a measurement greater than a set point value, sets an output signal that controls the tripping of a CB. Such systems should be very reliable to not give false alarms or, even worse, cause nuisance tripping of the CB.

Wireless temperature monitoring sensors may be installed on electrical equipment at the points that are not accessible with the power on. To provide continuous uninterrupted service the sensors must have a very high service life and high mean time to failure (MTTF), which is the sensor's reliability calculated over its designed lifetime. Long service life of temperature monitoring is defined by a reliable and independent power source for the sensors.

7.6.5.3 Wireless Temperature Sensors: Power Source

In wireless temperature sensing the search for reliable power supply is very important. A traditional way of supplying energy to a wireless sensor is by using primary (nonrechargeable) batteries, whose main weakness is the limited amount of available energy. The life of the battery depends on ambient temperature. Considering the application of sensors in electrical installation, ambient temperature will be always elevated, thus significantly shortening the battery's useful life. To keep the sensor functioning, the battery should be replaced when depleted.

By definition, wireless autonomous sensors must not depend on an external power supply. Energy harvesting is a means of extending the lifetime of the autonomous

sensor beyond the life of a battery [61]. Several dominant energy-harvesting technologies are known. Choosing one or another energy-harvesting technology application depends on the type of equipment where the wireless sensors are used.

One of these technologies is using *photovoltaic* elements [62], which produce electricity from ambient light—either indoors or outdoors. Photovoltaic cells produce electricity from photons by means of a semiconductor p – n junction. This technology is at a relatively advanced stage of development.

Vibration harvesters [63,64] are using electromagnetic, piezoelectric, or electrostatic phenomena and may produce electricity from vibrations of the surface the sensor is deployed on. Electromagnetic generators use a resonant magnet and coil arrangement to generate electricity, whereas piezoelectric-based generators use a piezoelectric resonant beam which generates electricity when subjected to strain. Electrostatic generators exploit capacitive effects but, due to machining and practical issues, have not become widespread. Vibration energy harvesters are sensitive to the frequency of vibrations of a surface, and their deployment is generally limited to machinery that vibrates at a constrained range of frequencies and amplitudes.

Thermoelectric elements [65] produce electricity from a temperature gradient. Thermoelectric energy sources exploit the Seebeck effect, in which electricity is generated from a temperature difference across a thermocouple. In general, thermoelectric devices require a large and sustained temperature gradient between two surfaces in order to provide useful power.

For application in the electrical industry, passive/remote power supply was used in temperature wireless sensing: *surface acoustic wave* (SAW) technology [66]. SAW sensors operate with no wire connection or battery; they do not need power supply. They are connected only by a radio frequency link to a transceiver or reader unit. A high-frequency electromagnetic wave is emitted from an RF transceiver and is received by the antenna of the SAW sensor.

The sensors are using interdigital transducers (IDT) that convert the electric field energy to mechanical wave energy and then back to an electric field. The transducers are connected to the antenna to convert the received signal into an acoustic wave, which propagates along the sensor. Depending on the construction of the device, the IDTs can retransmit the signal to the receiver. The received signal is amplified and then converted to a baseband frequency in the RF module and then analyzed by a signal processor. Because the operating frequencies are high, SAW sensors are well protected from electromagnetic interference that often occurs in the vicinity of industrial equipment, such as motors and HV lines.

7.6.5.4 Wireless Temperature Monitoring Techniques

Traditional methods of measuring temperature have relied on the temperature dependence of resistance (thermistors or RTDs), a variety of different types of thermometers, the temperature dependence of a diode junction (silicon), or the emission of infrared radiation from heated objects (IR sensors).

Passive devices such as thermocouples and RTD require battery-powered transmitters to communicate information. This complicates measuring the temperature of contacts and connections in HV switchboxes and transmission. A standard requirement for these systems is that there be no metallic or fiber-optic cabling from the

contact or connection of interest to the supporting structure or frame, as this can cause a dangerous and potentially explosive path to the ground.

Infrared thermometry is sometimes employed, but this requires a direct line of sight to the area of interest, which should be clean for best accuracy and is more often used for spot checking on a periodic basis and therefore not for continuous monitoring. Typically the infrared measurement systems used for this type of monitoring are cost prohibitive. Battery-powered temperature-transmitting systems have drawbacks related to the typical physical size and the need for inconvenient periodic replacement of the battery. With a few exceptions, batteries are not well suited for high-temperature operation, especially above 150°C.

7.6.5.5 Wireless Temperature Monitoring with SAW Sensors

SAW technology is using the effect of changing the parameters of an acoustic wave, such as velocity and amplitude, when it propagates through or on the surface of the piezoelectric material depending on the physical condition of the material. Any changes to the characteristics of the propagation path affect the velocity and/or amplitude of the acoustic wave.

Changes in velocity can be monitored by measuring the frequency or phase characteristics of the sensor and can then be correlated to the corresponding physical quantity being measured. SAW sensors are very sensitive in measuring mechanical properties such as stress or strain. Special cuts of piezoelectric substrate create SAW devices with a very linear SAW frequency versus temperature dependence. The result is a very-high-resolution temperature sensor.

In WTMS based on SAW technology, the number of sensors is limited to no more than a few. In this technology the measured quantity (temperature) is calculated from the frequency range; thus every sensor must occupy its own frequency range.

This limitation may have significant impact on the applicability of SAW sensors for complex condition monitoring of an electrical system, such as switchgear components. An average switchgear frame contains about 12 hot spots: three each for main bus, for cable terminators, for breaker inputs and for breaker outputs. Switchgear interiors contain a number of conducting metal plates and other components that reflect and degrade radio signals, which cause difficulties in using this technology. To apply a set of SAW sensors to measure temperature in all 12 locations in each cubicle of switchgear, a special layout of the sensors is required. The solution [67] was found by antenna tuning, so that shielding capabilities of the switchgear cubicle boxes divided the switchgear into sections that contain sensors operating at different frequencies, while frequencies in different sections were duplicated. It allowed installation of 72 sensors on the switchgear to monitor all expected hot spots.

Utilization of miniature SAW sensors enables monitoring of breaker connectors and noninvasive installation inside the switchgear. The small size of sensors allows the system to be extremely flexible in choosing measurement locations. Passive power supply enables indefinite lifetime of the system regardless of the external condition, which is a significant benefit of self-powering devices.

Passive wireless temperature sensors using SAW technology are a promising monitoring and diagnostic solution for critical equipment such as MV and HV switchgears. They provide a very important diagnostic means for the protection of

switchgear from catastrophic failure damage. Application of wireless temperature monitoring allows to prevent expensive outages and improve the safety of switchgear technicians and maintenance personnel. It may be considered as a valuable replacement for existing traditional temperature-sensing solutions within the switchgear application [68].

7.7 PHYSICAL CONDITIONS OF TRANSMISSION ELECTRICAL EQUIPMENT: ONLINE MONITORING TECHNIQUES

7.7.1 CONDITION MONITORING TECHNOLOGIES IN ELECTRICAL TRANSMISSION

Online condition monitoring is generally achieved through the use of specialized sensors or devices. The technologies used in these sensors have been around for several decades, their application to HV electrical equipment is relatively recent.

Online monitoring devices range from single-function monitors such as dissolved gas in oil and moisture in oil monitors, to more complex devices that monitor a range of parameters from electrical equipment, such as tap changers and CBs. The number of devices available is continually growing, and new ones are regularly developed and marketed [69].

There are online monitoring devices that monitor HV transformer dissolved gas and moisture in oil; transformer temperature monitors (including high-accuracy optical fiber temperature sensors). Other devices monitor CT and bushing dielectric dissipation factor (DDF) and PD. There are monitors that measure oil level and oil flow for oil-filled transformers. Many monitors are developed for other electrical equipment including CBs, batteries, and backup diesel generators to determine additional information such as loadings and ambient temperature that is also a useful information for equipment monitoring.

Some utilities around the world develop integrated online monitoring systems that manage information from a wide range of these devices across an entire HV network. For example, the system described in Ref. [70] is able to handle the following types of information: analog quantities, such as DGA and moisture; digital quantities, such as extended CB alarms; records from protection relays, CBs, tap changers and battery tests; and plain text information, such as flag information from modern protection relays. Even in its early stages the system has been able to provide a range of information on a variety of equipment, which has served a number of purposes. The main advantages that utilities have found with this system are easy and flexible access to online monitoring data and the ability to use these data for automated analysis as required.

7.7.2 OVERHEAD TRANSMISSION LINES

The safety and benefits of the electric power system highly depend on proper functioning of HV overhead transmission lines (OHTL), which are the arteries of the electric power system.

The temperature of an energized conductor either in overhead transmission or distribution lines, as well as underground cables, is a very important physical property

that carries information both on the conditions of a conductor as well as on the load. The major concerns about the condition of OHTL could be divided into two major groups. One is an aging process that leads to the deterioration of all components of transmission lines, including the wires, transmission towers, and insulators. Another concern is the need to increase the power load of existing lines depending on the physical conditions of the lines.

There are several mechanisms that affect the health of transmission lines, and the most serious aging processes are the ones that impact all components of the line. These are extreme temperature changes, wind-induced motions, corrosion, and contamination.

Utilities are running OHTL at operating temperatures exceeding 90°C, especially under emergency conditions. High-temperature operation of OHTL results in degradation of the materials, which affects mechanical strength of the cables and joints. With the deregulation of the power industry, there are increasing pressures on transmission and distribution providers to increase the utilization of their existing assets. This means that increasing power delivery will require raising further the allowable operating temperatures of the conductors in the system. Thus, while 125°C is considered a practical limit to emergency loading, higher temperatures of 150°C, 175°C or more are used in some cases. The aluminum or copper conductors of overhead lines lose tensile strength and permanently elongate at a high temperature.

Overhead conductors in transmission and power distribution are usually made of aluminum known as: all-aluminum conductor or AAC, AAAC, aluminum conductor alloy reinforced (ACAR) and ACSR.

An all-aluminum conductor loses no significant strength at temperatures below 95°C (203°F) but may lose 25% of its tensile strength when subjected to a temperature of 150°C (302°F) for 1000 h. Similarly, the normal sag increase of ACAR, AAAC or AAC conductors as a result of creep elongation over time may be many times greater after extended operation at high temperature. Corrosion of components is also accelerated by high temperature.

The effect of long exposure to high temperature on mechanical properties of the materials used for transmission cables and joints has been studied in Ref. [71]. The results of the study indicate that operation of a typical transmission conductor (ACSR) at high temperatures will reduce the mechanical integrity of the overhead system. It is clear from the metallurgical and tensile tests that cumulative damage occurs to the aluminum metal in overhead conductors that have been subjected to high operating temperatures. System joints are exposed less to the higher operating temperatures owing to the larger mass and surface area in comparison to the conductor. These factors allow the joint to operate at a lower temperature than the conductor as long as the joint CR remains low. It is possible to extend the full mechanical life of the conductors by minimizing the duration that existing ACSR OHTL are exposed to high operating temperatures.

In Europe the extra high voltage (EHV) OHTL were mainly built in the early eighties and in the seventies of the last century according to national and international standards. The sag of overhead lines are dimensioned at a specific temperature, which is commonly 60°C for the standard ACSR conductor, because the reversible tension of the conductor depends mainly on the temperature, when there

is no additional external load (like ice) on the conductor. The rated current at a conductor temperature of 80°C is defined by specified environmental conditions. These conditions are: 35°C ambient temperature, 0.6 m/s wind and usual solar radiation [72]. It was found that approximately 40–50 year-old conductors have been creeping by several mechanisms [73,74].

To prevent a long duration of transmission line exposure to high temperatures, it is necessary to monitor the temperature of joints and conductors continuously. Having this information will significantly improve the safety of transmission lines and help to prevent unpredicted outages. This information could be used for scheduling a condition-based maintenance and will optimize the power delivery and improve overhead line ratings when conditions allow it. For example, when utilities calculate static rating, they must assume the worst ambient conditions, which is usually the highest summertime temperature. Such an approach results in ratings that are much lower than the true power capacity of the line for most of the year. Therefore, transmission lines often have significant hidden capacity that could be used if information on conductor temperature and sag on a real-time basis (dynamic rating) was available.

The research and development activity in such organizations as EPRI has increased based on a growing demand for the development of a means of monitoring the conditions and dynamic thermal circuit rating of transmission lines. Current EPRI projects are focused on the study of performance and aging characteristics of transmission equipment at increased operating temperature. In other projects, space potential probes for the real-time monitoring of the conductor sag and average core temperature are being developed, as well as SAW sensors and fiber-distributed temperature sensors for transmission line applications, and so on. Other EPRI projects include the monitoring of wind-induced (aeolian) vibrations of transmission lines, which cause damage to conductors and towers, and the development of sensors for the detection of defective compression connectors.

The best way to monitor the conditions of transmission lines would be by real-time and permanent monitoring, with sensors that do not require power supply and that may be mounted on hotline without outage. The monitoring should be nondestructive and nonintrusive; it should be secure and controllable. Real-time monitoring of transmission lines allows the detection of imminent failure events. For example, by recording the variation of tension with temperature, the monitoring may remotely detect the breaks in the steel core of ACSR line or structure support failures.

7.7.3 PROPERTIES OF TRANSMISSION OVERHEAD LINES TO MONITOR, SENSING ELEMENTS AND MONITORING TECHNIQUES

There are several very important parameters that define transmission line health, such as the *temperature* and *sag* of the lines. Knowledge of these parameters would allow preventing the failures caused by wire damage and increase the power flow. There are other conditions of transmission lines that need to be monitored. Insulators might be severely damaged by *corona*, which might be monitored with corona-discharge and electromagnetic acoustic transducer (EMAT) sensors. UV imaging technology detects UV emitted by corona in damaged insulators. Wind-induced

vibration of the overhead lines due to strong winds, the so-called aeolian vibration, leading to serious damage of the cables, may be measured with vibration recorders. For example, a device called SEFAC is developed for a conductor diameter of 3 cm, but the existing device is too heavy, costly (>\$10 k), and not very reliable.

7.7.3.1 Conductor Sag Measurements

There are several known methods to measure or evaluate the sag of the wires, such as measuring wire strain/tension, distance to the target, line temperature and weather monitoring. *Tension* of the conductor may be measured with the strain gages installed in series with a dead-end insulator string measuring the tension of the line conductor. A transmission line monitoring system (CAT-1) is described in Ref. [75]. CAT-1 stands for “Clearance Assurance of Transmission.” CAT-1 measures the various tensions and sags in a transmission line based on actual weather conditions. CAT-1 is using load cells for measuring the strain in the conductor. The price tag on a CAT-1 system is roughly \$100,000 per transmission line—more or less depending on the length of the line—and it usually takes one to two days to install the equipment on the lines. Installation required an outage.

The 2003 report “Development of a Real Time Monitoring/Dynamic Rating System for Overhead Lines” [76] described development and testing results for two techniques for sag measurement. In one device, a laser distance meter (LDM) is used. Another one uses machine vision, or Point Source to Tower Measurement (PSTM), based on optical monitoring of the conductor itself of a passive target mounted on a set distance from the vision system. The system called “Video Sagometer” or just “Sagometer” is considered to be the better one. This system was developed by EPRI, EDM International, and SwRI (Southwest Research Institute) [77,78]. EPRI was developing space potential probes for sag measurement [79].

7.7.3.2 Conductor Temperature Measurements

The temperature of the cable is determined by thermal energy that is produced by the current and the heat induced by the solar radiation. At the same time there are several processes that cool down the cable, such as heat convection due to ambient air movement/wind and through thermal radiation [80]. The total input heat to the conductor in the overhead line is a sum of the heat of input due to line current and the heat input due to solar energy. In stable condition the total input heat to the conductor must be equal to the total heat output, which is defined as a sum of the heat output due to convection (a function of wind, air temperature, conductor temperature) and the heat output due to radiation (a function of air and conductor temperatures).

The temperature of a conductor may be measured with a device mounted on the conductor. It may be installed on an energized conductor using a hot stick. This device directly measures the line temperature and has a radio transmitter, which transmits the information to a receiver on the ground or on the transmission tower. Air temperature should also be measured to determine the TR on the conductor. Knowing the conductor temperature, air temperature, incident solar radiation and line current, the rating can be calculated.

7.7.3.2.1 *Fiber-Optic Instruments*

In 2003 two American companies completed a 2-year field trial of the temperature monitor using a fiber-optic transmission conductor (FOTC) [81]. Communication fibers were stranded into the conventional ACSR conductor providing accurate profiles of the conductor temperature. Optical fibers installed in the conductor communicate with an instrument at one end of the line to report the temperature. FOTC is an application of distributed temperature sensing (DTS) whose first applications were in the aerospace industry. Later, this temperature monitoring system was applied to *underground cable* systems to identify localized hot spots. DTS determines temperatures by watching the optical fiber change color as the temperature changes. A pulse of light sent down the fiber is partially reflected from every part of the long fiber back to the source. The reflection time determines the location of the elevated temperature. Depending on the desired resolution and based on the number of readings per foot, DTS has a range of up to 30 miles (48 km).

EPRI developed and evaluated another distributed temperature-monitoring system using chirped Bragg grated optic fiber [82]. A similar embedded distributed temperature-monitoring system was developed in Europe. It uses a different version of temperature monitoring of the energized cable—fiber-optic temperature laser radar, also based on fiber-optic technology [83]. A fiber-optic transceiver (FTR) sends a light impulse along the fiber-optic cable, and calculates the temperature and the distance to the point at the distance up to 6 km, with the separation between the points of 2 m. These systems [84], based on fiber-optic distributed temperature sensors, monitor the temperature of 400 and 230 kV underground power cables between the power station and local substations and monitor the whole length of the transmission circuits, including circuits longer than 24 km. The systems are used for reporting and locating temperature excursions, thus enabling the power company to optimize its cable assets and ensure reliable supplies of electricity.

In general, the majority of transmission overhead line temperature monitoring systems are based on fiber-optic technology or distributed temperature measurement. However, none of the systems have found wide practical application until now. The downsides of such technique are the necessity of fiber-optic cable installation on the power cable and the extremely high cost of the system.

7.7.3.2.2 *SAW Temperature Monitoring*

SAW sensors (see Section 7.6) could be used for temperature measurement at HV OHTL with a radio link for the connection between the sensor and the measuring unit. The SAW system is using a high-frequency electromagnetic wave at the 2.45 GHz ISM band, which is transmitted to the sensor by the use of a transmitting antenna of the measuring system. By using the transducer, which is connected with the sensor chip, the incoming high-frequency signal is transmitted to acoustic surface wave, which is dispersed along the surface of the crystal and reflected on integrated reflectors. The propagation velocity of the acoustic surface wave depends on temperature. The reflected signals are converted to high transmission frequency by the transducer and sent back to the receiving antenna of the system.

The information of the sensor ID and the temperature information can be determined by the reflected impulses using various algorithms, which compute this information using the time position and the phase relation of the reflected impulses by commonly used signal processing techniques. The results can be displayed on a personal computer. The sensors are passive and can withstand the common transient and power frequency stress on OHTL. For usage at overhead lines a suitable clamp was designed so as to be easily installed and to fulfill the mechanical and electrical requirements. The data acquisition unit was designed for installations on EHV overhead line towers. After positive results with this measuring technique the system was also installed at various OHTLs and substations [85].

7.7.3.3 Combined Monitoring Solutions

There are several systems that are able to monitor multiple parameters of overhead transmission lines continuously.

The Power Donut2™ (PD2) is an instrumentation platform whose functions include measuring and monitoring the electrical, thermal, and mechanical parameters of HV overhead conductors in power transmission systems [86]. The device is mounted onto an energized power conductor with a hot stick; its installation can be done with no scheduled outage. The Power-Donut2™ is powered from the electromagnetic field surrounding the energized conductor. It has a long-life lithium battery pack that maintains operation for up to 12 h when current is below nominal, that is, 50 A. PD2 measures conductor load (amperes), conductor temperatures and conductor sag (inclination angle) in real time, and monitors each parameter against user-defined warning and alarm level set points.

PD2 measures the conductor inclination in real time. The user can enter the conductor specifications including conductor weight, horizontal span for the section of line that PD2 is attached and the tower height difference. This information allows to compute conductor sag relative to the tower near PD2, and tension at both ends of the conductor. Warning and alarm levels can be monitored for these computed values. The Power-Donut2™ has on-board flash RAM memory for data logging, thereby providing secure local historical trend data. Historical data are automatically transferred to the communicating device for additional data security. When equipped with license-free radios, PD2 reports warnings and alarms virtually instantaneously. PD2 is supplied with the cell phone communication option, which initiates communication with the central office to report the warning or alarm condition within 60 s of the event.

7.7.3.3.1 LIOS Monitoring System

The system allows simultaneous monitoring of cable temperature and PD activity [87]. It is based on a combined DTS equipment and PD measuring technique, which provides grid owners a better means of controlling and monitoring their grids. This approach allows most of the failure modes of the apparatus and electrical assets to be diagnosed, thus increasing reliability and decreasing maintenance costs. The system supports different sensors (PD, DGA, DTS, Tan-delta, and Vibrations) and integrates diagnostic algorithms to data coming from these sensors.

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8 Electrical Equipment Maintenance and Life Extension Techniques

As soon as new electrical equipment is installed in service, the aging process begins, with the rate depending on the application, environment, maintenance quality, and many other conditions that shorten the life of the equipment. Most of the electrical power equipment in use today have already deteriorated to different degrees; some remain in service for several decades. As soon as the performance of the electrical equipment begins to decline, knowledge about various life-extension techniques for electrical equipment becomes very important. Aging electrical equipment are often retrofilled, retrofitted, or rebuilt, which means that either the parts or the whole unit is replaced with new ones. This is a valuable solution near the end of the equipment life or if the conditions are so bad that failure is practically unavoidable or if some parts are obsolete and there is no way to fix them. On the other hand, there is a continuous, affordable and justified way of keeping the equipment in good and properly working conditions by providing a timely, thorough and educated maintenance—the best way to extend the life of the equipment is starting as soon as is recommended by the manufacturer after installation. Different approaches to maintaining electrical equipment as the means of extending its life in service are presented in this chapter.

8.1 MAINTENANCE STRATEGIES

The simplest maintenance strategy is based on the old philosophy: if it is not broken, do not fix it. It is called *corrective maintenance* (CM), which is based on restoring operation by fixing or replacing a component in case of failure, and it does not include any additional maintenance inspections. CM is usually the optimal solution at facilities where a failure of components has only a minor impact and it would be more expensive to monitor components' condition in service. In distribution systems, this kind of maintenance may be applied in the minor branches of an LV network.

Traditionally, electric utility maintenance strategies have been based on a fixed interval or number of operations; this is called a *time-based maintenance* (TBM), which even nowadays is quite a common maintenance policy used worldwide. Another term for this fixed interval maintenance is *periodic maintenance* (PM). Very often, TBM may be inefficient in controlling the lifetime of components. It is labor-intensive and ineffective in identifying problems that develop between scheduled inspections. For those equipment in continuous operation but still available for

planned periods, TBM is suitable, but not necessarily always. For example, a breaker used for capacitor or reactor switching is operated frequently and soon reaches thousands of cycles, in which case TBM is recommended. But other breakers may only operate once or twice per year. Moreover, TBM may not be cost-effective, which was the cause of the development of different approaches to keeping electrical power system in a healthy condition.

Maintenance based on equipment condition and not on the number of operations or years in service provides better judgment on what is needed and when. As more and more techniques that monitor equipments' physical conditions became available, a new strategy was developed—*condition-based maintenance* (CBM)—a strategy that takes advantage of the information obtained through condition monitoring. In using this strategy, maintenance is based on the needs and priorities. CBM tasks are based on an evaluation of the equipment condition by performing periodic or continuous (online) equipment condition monitoring. Predictive maintenance (PdM) is another name for CBM.

The ultimate goal of CBM/PdM is to perform maintenance at a scheduled point in time when the maintenance activity will be most cost-effective and before the equipment loses performance or fails. This is in contrast to TBM, where a piece of equipment gets maintained whether it needs it or not. The “predictive” component of PdM stems from a goal of predicting the future trend of the equipment's condition. This approach uses the principles of statistical process control to determine at what time in the future it will be very appropriate to carry out maintenance activities. Most PdM inspections are performed while the equipment is in service, thereby minimizing disruption of the normal system operations. Adoption of PdM can result in substantial cost saving and a higher system reliability.

When the condition of the component is combined with the importance of the component from a functional point of view, another type of maintenance strategy is introduced—*reliability-centered maintenance* (RCM). RCM is not a single method, but allows comparison of different maintenance methods, of which the most cost-effective one can be chosen without compromising on reliability. RCM can also be seen as a process where the role of other maintenance strategies (CM, TBM, CBM) is optimized. For example, using PdM can enable better outage scheduling, flexibility of operation, a more efficient management of spare parts, and so on [1]. With RCM, the consequences of a failure are additionally evaluated. RCM is the right amount of maintenance for the right equipment at the right time. Unfortunately, sometimes, RCM is reduced to a fourth principle: no maintenance. This is the least desirable option and leads to costly disturbances in the long run.

The role of RCM at the system level is to balance the spending in maintenance activities with their effect on system performance. Usually, the aim is to maximize the result with regard to system reliability or outage cost reduction. In distribution networks, the RCM process includes identifying the critical system levels from the reliability point of view and selecting suitable strategies for different levels. For assessing the criticality of different components and system levels, standard reliability analysis methods are used. Some guidelines, with typical fault statistic data, are given in IEEE Standard 4931997, “IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (Gold Book)” [2].

New maintenance strategies may be developed based on finding an optimal balance between the maintenance cost and the ability to maintain sufficient reliability in the system [3].

8.2 MAINTENANCE AS A LIFE EXTENSION TECHNIQUE

8.2.1 TIME-BASED MAINTENANCE

TBM (or PM) remains one of the most often used techniques to keep electrical equipment in proper working conditions. Original equipment manufacturer (OEM) user manuals usually have a special maintenance section where the intervals for maintenance actions are specified. For example, all leading switchgear manufacturers provide detailed maintenance guidelines for their switchgear. If switchgear is maintained according to these guidelines it can be expected to last for over 40 years.

Unfortunately, the importance of maintenance is often underestimated until it is too late, that is, until a fatal or serious failure occurs. Some of the reasons for none or poor maintenance are a lack of product knowledge and insufficient funds. TBM is usually performed on critical system components, such as primary transformers and primary substation switchgear. For safety reasons, security codes usually require some inspections to be made on a regular basis, thus leading to the mandatory use of TBM, such as the inspection of earthings in primary and secondary substations.

Recommended maintenance intervals for the most important components are given in Ref. [1]. For example, the most frequent maintenance interval for transformers and CBs should be 1 year, minor overhaul is recommended to be done every 5 years, while major overhaul should be performed once every 7 years for transformers, and every 8–10 years for CBs. PM always includes a number of tests, which are specified in Ref. [4].

8.2.2 MAINTENANCE OF POWER CIRCUIT BREAKERS

8.2.2.1 Molded Case Circuit Breakers

MCCB are designed to require little or no routine maintenance throughout their normal lifetime; however, the maintenance of MCCBs deserves special consideration because of their importance for routine switching and for the protection of other equipment. Electric transmission system breakups and equipment destruction can occur if an MCCB fails to operate because of a lack of periodic/preventive maintenance. The need for maintenance of CBs is often not obvious as CBs may remain idle, either open or closed, for long periods of time. Breakers that remain idle for 6 months or more should be made to open and close several times in succession to verify proper operation and remove any accumulation of dust or foreign material on moving parts and contacts.

MCCB should be exercised at least once per year. This manual exercise helps to keep the contacts clean, due to their wiping action, and ensures that the operating mechanism moves freely. This exercise, however, does not operate the mechanical linkages in the tripping mechanism. The only way to properly exercise the entire

breaker operating and tripping mechanisms is to remove the breaker from service and test the overcurrent and short-circuit tripping capabilities. A stiff or sticky mechanism can cause an unintentional time delay in its operation under fault conditions.

8.2.2.2 Low-Voltage Circuit Breakers

LV CBs operating at 600 VAC and below should be inspected and maintained every 1–3 years, depending on their service and operating conditions. More frequent maintenance and inspection are necessary if LV CBs are exposed to high humidity and high ambient temperature, and a dusty, dirty, or corrosive atmosphere. Older equipment and the breakers that provide frequent switching or fault operations also require more frequent maintenance. A breaker should be inspected and maintained if necessary whenever it has interrupted current at or near its rated capacity [5].

The manufacturer's instructions for each CB that usually describe general procedures should be carefully followed in the maintenance of LV air CBs. The breakers should be carefully inspected. Insulating parts, including bushings, should be wiped clean of dust and smoke, the alignment and condition of the movable and stationary contacts should be checked and adjusted, and all other required procedures should be performed according to the OEM's manual.

8.2.2.3 Medium-Voltage Circuit Breakers

There are many varieties of MV CBs based on different technologies, such as using live tank technology with vacuum, air, oil or SF₆ as the interrupting media, and dead tank technology with oil, SF₆, and so on. This is also true for HV CBs. MV CBs which operate in the range of 600–15,000 V should be inspected and maintained either annually or after every 2000 operations, whichever comes first. This maintenance schedule is recommended by the applicable standards to achieve the required performance from the breakers. For MV air CBs, all OEM's manuals provide the requirements for a proper maintenance. It includes cleaning of the insulating parts including the bushings, checking the alignment and condition of movable and stationary contacts and their adjustment according to the manufacturer's data, and cleaning and lubricating the operating mechanism exactly as described in the instruction book. Worn parts should be replaced.

The maintenance of MV OCBs includes thoroughly cleaning the tank and other parts that have been in contact with the oil. An important part of the oil-filled MV breakers is the testing of the dielectric strength of the oil, which is defined as the maximum voltage that can be applied across the fluid without electrical breakdown (see ASTM D300-00). If it is <22 kV, then the oil should be filtered or replaced. The oil should also be filtered or replaced whenever a visual inspection shows an excessive amount of carbon, even if the dielectric strength is satisfactory. During these procedures it is important to be sure that the gaskets are undamaged and all nuts and valves are tightened properly to prevent oil leakage [5,6].

8.2.2.4 High-Voltage Circuit Breakers

Most manufacturers recommend external and internal inspections at intervals ranging from 6 to 12 months. However, with proper external checks, frequent internal inspections may be avoided. The inspection schedule should be based on the

interrupting duty imposed on the breaker. It is recommended to make a complete internal inspection after the first severe fault interruption. If internal conditions are satisfactory, progressively more fault interruptions may be allowed before an internal inspection is made. Average experience indicates that up to five fault interruptions are allowed between inspections on HV CBs of voltage class 230 kV and above, and up to 10 fault interruptions are allowed on CBs rated under 230 kV. Normally, not more than 2 years should elapse between external inspections or 4 years between internal inspections [5].

An internal inspection should include all items applied to an external inspection, in addition to that the breaker tanks or contact heads should be opened and the contacts and interrupting parts should be inspected. There are several problems which should be looked into during internal HV breaker inspections [5], such as the tendency for carbon or sludge to form and accumulate in interrupters or on bushings. Among other issues is the tendency for interrupter parts or barriers to burn or erode. The bushing gaskets may leak moisture into breaker insulating material, among other issues [5].

8.2.2.5 SF₆ Gas Circuit Breakers

Some of the maintenance issues are determined by the SF₆ gas effect on humans. Although, in pure state, SF₆ gas is nontoxic, it can exclude oxygen and cause suffocation. If the normal oxygen content of air is reduced from 21% to <13%, suffocation can occur without warning. Therefore, CB tanks should be purged out after opening them. Toxic decomposition products are formed when SF₆ gas is subjected to an electric arc. The decomposition products are metal fluorides and form a white or tan powder. Solid arc products, if they come into contact with the skin, may cause irritation or possible painful fluoride burn. Toxic gases are also formed, and they have the characteristic odor of rotten eggs. Therefore, maintenance personnel should not breathe the vapors remaining in a CB where arcing or corona discharges have occurred in the gas, and should thoroughly wash off all the solid SF₆ decomposition products. The faulted SF₆ gas from the CB should be evacuated and flushed with fresh air before one starts working on the CB [5].

8.2.3 PERIODIC LUBRICATION OF THE POWER CIRCUIT BREAKER

Almost all power CBs require periodic renewal of lubrication in their operating mechanism. There are several factors determining the frequency at which lubrication should be renewed [7]: the continuous current rating of the CB; the number of close–open operations since the most recent renewal; the time elapsed since the most recent renewal; and the CB's operational environment. For LV power CBs, the minimum number of close–open operations that a breaker must be able to accomplish before requiring service is specified in IEEE Standard C37.16 [8]. The lubrication in a CB's mechanism needs to be renewed after the number of operations specified in that standard.

The OEMs are allowed to suggest a greater number of operations than the number given in the manufacturing standard [8], depending on the continuous current rating of the breaker. For example, although an 800 A-rated CB is required by the

manufacturing standard to endure 500 operations before service is needed, a manufacturer's instruction book might indicate that an 800 A-rated breaker would require renewal of lubrication after 1750 operations.

If a CB operates only a few times each year, a 500- or 1750-operation count might never happen within the useful life of the breaker. A requirement for renew lubrication still stands because all lubrication materials deteriorate when exposed to air. This deterioration is accelerated by environmental conditions such as elevated air temperature or the presence of airborne contaminants (see Chapter 4).

Most users launch the programs to lubricate critical CBs based on an established time interval. Malfunctions have been attributed to a failure of lubrication for CBs having as little as 5 years of normal service. The lubrication points that typically require critical attention are usually specified in the OEM user manual and these requirements should be followed. Lubrication of the bearing surfaces of the HV CB operating mechanism should be performed according to the manufacturer's used manual; however, excessive lubrication should be avoided, because oily surfaces collect dust and grit and get stiff in cold weather, resulting in excessive friction.

There is a large variety of materials that are used to lubricate a CB's mechanism. More than one type of lubrication material might be used in the same mechanism at different specific points. Additionally, the material that is recommended for renewal of lubrication is sometimes not the same material that was installed at the factory. It is important to use the material that is specified in a CB's OEM manual to avoid incompatibility problems (see Chapter 4).

Current-carrying components also require periodic lubrication, and OEMs specify lubrication products and terms of lubrication in instruction manuals. Current-carrying components of a CB might include main contacts, primary-circuit finger clusters, and bus studs. Some current-carrying parts should never be lubricated, which is also specified in the manuals. Information on lubrication recommendations including lubrication products, points and terms of lubrication of major manufacturers of electrical MV and LV equipment is summarized in Ref. [9].

Since many types of CBs do not operate often and lubricants tend to harden and deteriorate with time, one very important rule is established to keep the lubricant in proper working conditions—to *exercise* the mechanism as often as possible. It will prevent the CB's failure to open, which is mostly caused by dried lubricant.

8.2.4 REFURBISHMENT OR RECONDITIONING

For the breaker that is not functioning properly, the reconditioning procedure includes disassembling of the CB to its component level (racking mechanism, operating mechanism, frame, all electrical components, and current-carrying parts). All component parts should be inspected and tested in the beginning of this procedure. Cleaning should be thorough and part-specific followed by lubrication of all parts as required by the OEM's user manual. Some specifics of cleaning and lubrication of current-carrying parts are described in Chapter 4 of this book. After assembly, the reconditioned CB should be inspected and tested again. An example is given in Ref. [10] of how an LV CB looks like before and after this procedure ([Figure 8.1](#)), a remarkable difference.

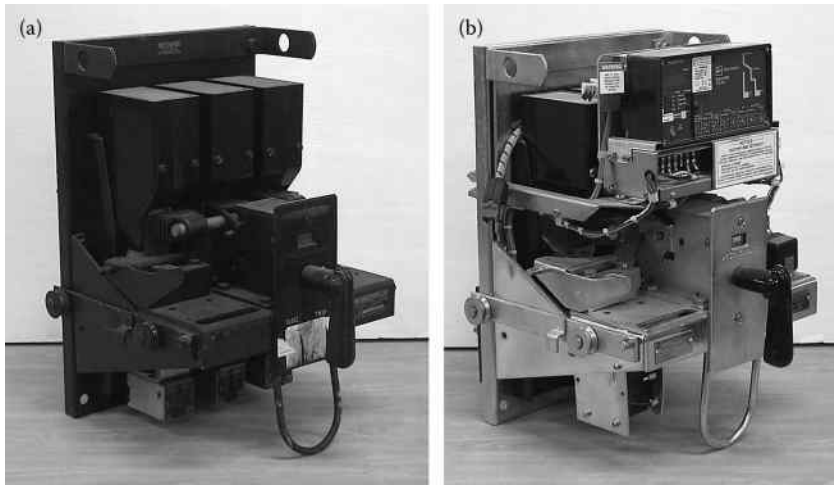


FIGURE 8.1 Westinghouse DB-25 CB before (a) and after reconditioning (b). (Courtesy of Eaton Corporation, form Biggs J. *Circuit Breaker Life Extension*, Presented at Western Mining Electrical Association Meeting, February 2011, Online. Available: <http://www.wmea.net/papers/Circuit%20Breaker%20Life%20Extension.pdf>. With permission.)

MV switchgear manufacturers have developed a number of alternative solutions to help customers find the best safety and life cycle management option for their equipment. Having more choices, each with different advantages and costs, enables customers to select the specific solution that best fits the overall business strategy of the plant.

One of these choices is refurbishment: the existing switchgear is fully overhauled and restored to an as new condition. If one or more main elements of the switchgear are found worn, they are replaced with modern equivalents (retrofit). Elements with the highest maintenance cost and failure risk can be targeted specifically. A combination of these two solutions for MV switchgear offers customers a life extension for their equipment at a low cost.

This option is attractive for customers with no imminent need to modernize, but wishing to maintain acceptable performance over a short- to medium-term life extension. Refurbishment of switchgear can take place in a number of ways: (a) refurbishment of the switching devices or (b) refurbishment of the complete panel. Switching devices such as CBs, contactors, and switches are typical candidates for refurbishment. The devices are removed from the switchgear, sometimes on a rotational basis in order to maintain continuity of supply, and returned to the manufacturer.

For refurbishment, each breaker is completely disassembled to the smallest components. In general, bearings, cotter pins, and other selected components are totally replaced. All other parts are thoroughly checked for wear and damage and are replaced as needed. Each component is cleaned and replated if required. Product enhancements that have developed since the original manufacture are implemented to bring the breaker up to the latest production standards. When such a refurbished breaker leaves the factory it has a new lease of life and a full new warranty [11].

8.2.5 CONDITION-BASED MAINTENANCE

The need for performing CBM using proper condition monitoring tools was revealed as early as in the 1960s by a study conducted for the development of a preventive maintenance program for Boeing 747. The study's purpose was to determine the failure characteristics of aircraft components [12]. The study was, at the request of the Department of Defense (DoD, USA), documented and published in 1978 [13]. It was found that a relatively small part of all components (11%) had clear aging characteristics which would enable a scheduled overhaul, that is, predetermined preventive maintenance. The rest of the components (89%) did not show such aging characteristics, which led to a conclusion that they were random failures which are, thus, not applicable to scheduled overhauls.

Similar conditional-probability curves within the manufacturing industry have been determined showing that only 30% of all components have clear aging characteristics, and that this percentage decreases as complexity and technology increase [14].

Evidently, when planning appropriate maintenance schedules, the aging feature of a component is not the best approach, and in some applications not even possible, thereby introducing CBM and condition monitoring as a reasonable solution to the issue [15]. CBM is defined as preventive maintenance based on performance and/or parameter monitoring and the subsequent actions. Therefore, CBM is a maintenance approach that utilizes condition monitoring in order to monitor the conditions over time and then uses its results in order to help to decide whether maintenance actions are required.

According to Ref. [16], CBM tasks are performed to determine whether a problem exists in the monitored item, how serious the problem is, and how long the item can be run before failure. CBM tasks also serve to detect and identify specific components in the items that are degrading, and diagnose the problem.

8.2.5.1 High-Voltage Switchgear

The development of novel comprehensive diagnostics for HV equipment became an integrated part of condition maintenance concepts. A combination of maintenance and measurement activities is covered by the application of CBM technology. One approach to HV switchgear CBM is used for reducing the maintenance costs without worsening the technical condition of the switchgear. It is achieved by focusing the maintenance and measurement activities on its critical components alone.

The benefits of the CBM approach increase considerably for significantly aged switchgear with a relatively high failure frequency, requiring high current maintenance costs and a long outage time for maintenance [12]. There are more indirect benefits of the CBM approach such as the use of the data on measured physical conditions as evidence in case of liability and extending the equipment lifetime by applying trend analyses of condition data.

Development of the CBM strategy is specific for each type of HV electrical equipment, because in each case different aging processes are involved in the aging of switchgear and therefore in the shortening of lifetime. In Ref. [16], such a CBM strategy was developed for HV switchgear for which the average age of CBs was about

35 years. An aging model of CB components is required in order to determine which components are of great importance to be maintained. As a part of the program, an attempt was made to determine which factors affect the condition of insulation material in HV CBs [17]. An insulation material called “Coqolite” was applied to a large number of this 35-year-old switchgear in the Netherlands and is defined as a critical component because of the replacement cost and the consequences for environmental safety in case of failure. It was found that the moisture level in oil influences the aging process of Coqolite, which requires a more frequent monitoring of moisture level in oil. The location of the substation also aggravates the aging of Coqolite because of the diversity of groundwater in different regions in the Netherlands. Paying extra attention to the moisture level of the oil of CBs in areas with high groundwater level should help extend the technical lifetime of critical components such as Coqolite. Reconditioning the oil above a moisture level of 11 ppm in these areas can be looked at as a precautionary measure for slowing down the aging process of the insulation.

A general review of aging parameters and ways to control them can enable to reduce maintenance activities, which lead to in a decrease of total outage time and consequently to a cost reduction per switchgear bay. Further cost reduction may be achieved through analysis of the stored condition data and optimization of the maintenance and monitoring program. On the other hand, extra costs are induced by the implementation of CBM, the use of software applications, increased engineering activities and additional measurement equipment. However, the costs per switchgear may significantly decrease if the total number of switchgear involved in the CBM program increases [12].

8.2.5.2 MV Switchgear

An application of CBM to the MV switchgear with the use of online temperature monitoring is described in Refs. [18,19]. A wireless temperature monitoring system was installed on two power plants to monitor the temperature of electrical contacts of aged equipment, which suffered multiple violent thermal failures in the past. The temperature data were continuously collected in the database and analyzed together with load data to determine any abnormalities in temperature behavior.

There could be two types of possible uses of the continuous temperature monitoring of electrical contacts. In one scenario for some unspecified reason, the temperature of the contact in good condition may suddenly increase above a predetermined level and the system issues an alarm requiring an immediate maintenance action to prevent thermal failure. The probability of such an event occurring is relatively low. On the other hand, a continuous observation of the temperature and analysis of the trends in temperature over a long period of time may allow to develop a reliable diagnostic tool for the contacts’ physical condition, which will justify a scheduling of the maintenance of the specific unit.

Almost 4 years after temperature monitoring began, the temperature on the power contact exceeded 100°C. Since the monitoring system high-temperature limit was preset at 95°C, this event triggered an alarm informing plant maintenance personnel that immediate measures should be taken. The breaker was removed from service, and the contact of the breaker were cleaned and maintained. The breaker was returned to service after proper testing.

At another power plant, a WTMS was installed in conjunction with a power monitoring system. This utility experienced multiple overheating problems on main breakers in the past, which resulted in violent thermal failures. Temperature monitoring sensors have been installed on two main breakers, on the surface of the insulation as close as possible to the bolted connections under insulation. After some strong changes in thermal behavior have been recorded, load conditions for the year of monitoring were analyzed. It was found that the power monitor recorded a severe overload of the breakers (for up to 20%) during at least 5 months during the previous summer and fall.

It was concluded that continuous overload of the breakers could be the major cause of irreversible damage done to the contacts' physical conditions. After being informed about observations and warned that further continuous overload may cause serious damage of the breakers, plant personnel did not load either breaker above the maximum rated current [19]. In this case, online continuous monitoring of the temperature of current-carrying parts allowed to avoid thermal failure of the breakers, saving significant assets, and provided justified maintenance activity, which is the meaning and goal of CBM.

8.3 CBM METHODOLOGY AND LIFE MANAGEMENT

8.3.1 DISTRIBUTION POWER TRANSFORMERS

With the restructuring of the electricity sector into a profit-oriented business entity, CBM strategies are focused on cost-effective solutions through effective asset management. For power transformers, an effective CBM program is crucial as more transformers have reached their service life. Diagnostic techniques are able to reveal a degradation state for effectively incorporating a transformer life management program. To provide CBM of distribution transformers, it was suggested to determine the so-called "transformer health index" (THI) [20]. The CBM program requires a proper selection of the diagnostic techniques, which are divided into three practical levels or tiers, subject to the availability of instruments and financial limitations.

8.3.1.1 Level 1 Diagnostic Techniques

According to the CBM program, Level 1 diagnostic techniques are applied on energized units to assess the presence of faults, quality of the insulating oil, degradation level of insulating paper as well as physical, thermal, and operating performance of the transformers. These tests include *dissolved gas analysis (DGA)* in the transformer main tank, with the results analyzed for key gases and TDCG concentrations as well as key gases and TDCG rate of generation in accordance with IEEE Standard C57.104 [21] and IEC 60599 [22] limits and interpretation.

According to *oil quality analysis (OQA)*, oil samples are tested for breakdown voltage, water content, acidity, and power factor. These tests are the basic routine tests for mineral insulating oil in accordance with IEC 60422:2005 [23], and are sufficient to indicate the condition of the insulating oil. Since the life of the cellulosic material is directly related to the life of the transformer, analysis of the furanic compound in oil or *furfural analysis (FFA)* should also be performed. By measuring

the quantity and types of furans present in a transformer oil sample, the insulation's overall Degree of Polymerization (DP) and remaining life estimation can also be done with a high degree of confidence.

Additional diagnostic techniques include inspection of transformer *physical conditions and operating performance*, which includes mechanical damage, corrosion, and oil leaks. This also includes a review of the transformer maintenance and performance historical records (on-load tap changer (OLTC) maintenance records and records of transformer internal and external tripping). *Infrared thermography* is also a part of the diagnostic as a technique indicating the thermal problems caused by overheating of conductors or deteriorated contacts. Infrared scanning is applied on the external components such as tanks, bushings, radiators, and cooling systems.

8.3.1.2 Level 2 Diagnostic Techniques

If the techniques included in Level 1 could not definitively classify some transformers as normal, then Level 2 diagnostic techniques should be used:

- *Transformer turns-ratio measurement* measured at every tap position of each phase against calculated nameplate values.
- *Winding resistance measurement* (DC test) performed at every tap position to detect broken conductor strands, loose connections, and bad contacts in the tap changer.
- *Dielectric dissipation factor/tan delta* measurement characterizing the amount of dielectric power loss which will produce heat in the insulation during transformer operation that can cause deterioration of the insulation.
- *Excitation current measurement* which detects short-circuited turns, core and winding problems and poor tap changer contacts [24].
- *Insulation resistance (IR) and polarization index (PI)* determining the presence or absence of harmful insulation contamination, degradation, and failure.

8.3.1.3 Level 3 Diagnostic Techniques

Finally, if both sets of diagnostic tests still could not definitively classify some transformers as normal, Level 3 diagnostic techniques are applied:

- *Frequency response analysis (FRA)* is used to detect faults such as short-circuited turns, movement, mechanical deformation, or displacement to windings or core and loose turns.
- *Partial discharge (PD)* measurement is used to detect the presence of PD activity, which is commonly related to moisture in the insulation, cavities in solid insulation, metallic particles, and gas bubbles generated due to some fault condition. A significant increase in PD level can provide an early indication of a failure.

8.3.1.4 Transformer Health Index

To capture and quantify the results of multiple diagnostic tests, the concept of THI was formulated in Ref. [25], with the value of THI ranging from 1 to 100. It was

used further to provide a qualitative indication of the condition of individual transformer accounting for the transformer age. Then each THI is ranked based on the Transformer Condition-Based Ranking to determine the next recommended maintenance actions. Out of 707 transformers, 49% have been found in “good” conditions ($85 \leq \text{THI} \leq 100$), 17% in “Fair” condition ($55 \leq \text{THI} < 85$), 29% in “Poor” condition ($10 \leq \text{THI} < 55$), and 5% in “Very Poor condition” ($\text{THI} < 10$).

It was found that a number of in-service transformers aged 5 years and below were diagnosed as in “Poor” conditions, with the oil having a considerably high concentration of gases that relate to overheating. Most common problems found for transformers aged above 30 years were paper degradation and deterioration in physical conditions. Based on the problems found from the assessment, the corrective actions were recommended and carried out.

Based on the values of THI, the condition-based maintenance actions have been planned accordingly to the transformers found in conditions ranging from “Fair” to “Very Poor.” Thirty transformers were selected for replacement or refurbishment, 138 transformers have been scheduled for regular monitoring of gas concentration and content of furans. Additional monitoring of thermal and loading conditions has been specified for 55 transformers, and 133 transformers should have the oil reconditioned.

This is a very valuable example of developing the CBM concept, which provided a specific approach to the assessment of electrical equipment conditions and allowed taking maintenance actions where and when they were needed the most.

8.3.2 POWER CABLE SYSTEMS

Power cables are the critical component of an electrical distribution system, and they must operate as long as possible according to reliability and safety standards. A vital part of the maintenance program is proper diagnostic testing to identify defects that result in a system failure. It helps to predict when these defects may induce failure in the cable system. The test should be economically justified within the condition-based maintenance concept and should not cause additional degradation to the system under test (see Chapter 6).

8.3.2.1 Cable Deterioration Diagnostics

Several diagnostic methods are available today that provide early identification of weak components of the cable system while the system remains energized. These methods can locate the degraded components of the system and determine the degree of degradation. This is essential for maintaining system reliability. As a part of condition-based maintenance, cost saving is achieved by prioritizing the replacement only of the weak sections of the cable system and rehabilitating the aged extruded cables. The degradation phenomena of power cables (see Chapter 6) are associated with PD and moisture ingress, which lead to thermal runaway failures. PDs are usually present at advanced stages of insulation degradation.

The majority of cable failures in an extruded cable system are related to water treeing, which lead to failure when they convert to electrical trees [25]. Once a water tree is converted to an electrical tree, the time to failure normally is very short,

because the initiated electrical tree propagates rapidly through the already weakened dielectric material. Electrical trees can also be formed as a result of PDs in large voids in cables, terminations, and joints.

Diagnostic technology called CableWISE [26] can detect, locate, and assess cable degradation. In this technique, radio frequency (RF) sensors are placed over the exterior of an energized shielded cable. RF signals emitted by the cable system while in service are detected, amplified, and then recorded for being analyzed later. Data analysis allows to locate the deterioration, which emits RF signals, and to determine the significance of deterioration. This type of deterioration diagnostics is beneficial compared with other diagnostic techniques (DC HIPOT, VLF) that apply overvoltage stresses to the cable during the test, with the possibility of inducing failure during the test or causing premature failure at a later time (Section 7.2).

The assessed condition of each cable component also depends on the type of cable insulation, influence of installation conditions, and previous condition assessments. The diagnostic technique provides the utilities with the guidance on managing assets properly and making educated and justified decisions on maintenance actions.

8.3.2.2 CBM and Life Extension of Power Cables

After the deterioration sites are located by diagnostic techniques in a power cable system, condition-based maintenance actions may include various methods to improve cable physical conditions with a focus on the weak sections of the cable. Technologies that can be used to extend the life of extruded cables have been in use since the mid-1980s [25]. Initially, nitrogen was flowed through the strands to dry the cable core and keep the water out, but it was expensive and high maintenance was required to continuously feed the nitrogen to the cable. Research findings [25] showed that a by-product of crosslinking process, acetophenone, hinders water tree formation in XLPE insulation. Acetophenone was then used for some time in the field instead of nitrogen, but this technique for extending the life was also discontinued in the field due to its several drawbacks.

In the late 1980s a new fluid based on silicone technology was developed and has been in use in the field effectively since then. This life enhancement fluid offers superior speed of treatment, increased cable life under harsh conditions of elevated temperature and many other advantages [27].

Additional research conducted over several years has led to the development of a new fluid called CableCURE especially suited for larger, hotter-running cables such as feeder cables. CableCURE is made up of 100% water reactive cable treatment fluids. Via molecular interaction, CableCURE eliminates water from the void as well as water diffusing through the cable. When the fluid comes in contact with water, it increases in molecular weight by polymerization, filling the cavities containing the water tree with a more viscous water-resistant fluid, thus preventing further tree growth. The main benefit of CableCURE cable rejuvenation is that it significantly extends the economically useful lifespan of an underground power distribution cable, deferring the cost of cable replacement by decades. A significant improvement in cable system reliability is achieved, thus leading to fewer, if any, outages due to dielectric breakdown.

8.4 MAINTENANCE OF ELECTRICAL EQUIPMENT EXPOSED TO CORROSION AND WATER

8.4.1 WATER-DAMAGED ELECTRICAL EQUIPMENT

Guidelines on how to handle electrical equipment that has been exposed to water through flooding, fire fighting activities, and hurricanes are outlined in the NEMA document [28] and in the recommendations of manufacturers and safety committees [29–31].

Electrical equipment exposed to water can be extremely dangerous if reenergized without proper reconditioning or replacement. Reductions in integrity of electrical insulation due to moisture, debris lodged in the equipment components, and other factors, can damage electrical equipment by affecting the ability of the equipment to perform its intended function. Damage to electrical equipment can also result from flood waters contaminated with chemicals, sewage, oil, and other debris that will affect the integrity and performance of the equipment. Ocean water and salt can be particularly damaging due to the corrosive and conductive nature of the salt water residue.

Switches and LV protective components such as MCCB and fuses, within assemblies such as enclosures, panel boards, and switchboards are critical to the safe operation of distribution circuits. By exposure to water and to the minerals and particles which may be present in the water, the ability of the components to protect these circuits is adversely affected. Such exposure can affect the overall operation of the mechanism through corrosion, the presence of foreign particles, and removal of lubricants. The condition of the contacts can be affected and the dielectric insulation capabilities of internal materials can be reduced. Exposure to water can cause corrosion and insulation damage to support structures, busways, wiring, electromechanical or electronic relays, and meters.

It is just a part of all possible damages, which could affect the electrical distribution equipment exposed to water, including corrosion, loss of lubrication, and deterioration of insulation quality. According to [28] most of water damaged equipment, such as electronically controlled and solid state contactors and starters, components containing semiconductors and transistors, overload relays, MCCB and switches, and fuses, should be completely replaced. Some of manual and magnetic motor controllers and motor control centers (MCC) may possibly be reconditioned.

In the case of *LV and MV CB and switches*, the operation of the mechanism can be impaired by corrosion, by the presence of particles such as silt (fine sand, clay, or other material carried by running water and deposited as a sediment), and by the removal of lubricants. The dielectric properties of insulation materials and insulators will degrade. For air CB, the condition of the contacts can be affected. Electronic trip units in LV power CB as well as the functionality of electronic protective relays and meters will be impaired.

It is possible that water-damaged LV and MV breakers could be maintained and returned to service by, for example, replacing contacts in air CB. However, the refurbishing of water-damaged power equipment including cleaning, drying, and lubrication should be performed in close consultation with the manufacturer. However, the

electronic trip units of LV power CB, and electronic protective relays and meters in any power equipment should be discarded and replaced, or at least returned to the manufacturer for inspection and possible refurbishment.

Exposure of *transformers* to water can cause corrosion and insulation damage to the transformer core and winding. The ability of the transformer to perform its intended function in a safe manner can also be impaired by debris and chemicals which may be deposited inside the transformer during a flood. Water and contaminants also can damage transformer fluids. All dry-type transformers regardless of kVA ratings and all dry type control circuit transformers should be completely replaced. Some liquid-filled and cast-resin transformers may possibly be reconditioned by trained personnel in consultation with manufacturer.

When any *wire or cable product* is exposed to water, all metallic components (such as the conductor, metallic shield, or armor) are subject to corrosion that can damage the component itself and/or cause termination failures. If water remains in MV cable, it could accelerate insulation deterioration, causing premature failure. Wire and cable listed for only dry locations may become a shock hazard, when energized, after being exposed to water. Any wire or cable listed for dry locations only, such as type NM-B cable, as well as any cable that contains fillers, such as polypropylene, paper, and so on should be replaced if it has been exposed to water.

The guidelines [28] also are given for handling of other water-damaged electrical equipment, such as wiring devices, ground fault circuit interrupters (GFCI), surge protectors, motors, and so on.

8.4.2 ELECTRICAL EQUIPMENT IN NUCLEAR INDUSTRY

The U.S. Department of Energy (DOE) and EPRI, in cooperation with nuclear power plant utilities and the Nuclear Energy Institute (NEI, formerly NUMARC, the Nuclear Management and Resources Council) have prepared guidelines for aging evaluations of nuclear power plant equipment for life extension considerations, including electrical equipment [32].

Aging Management Guidelines (AMGs) provide guidance on performing detailed evaluations of aging mechanisms and aging management strategies applicable to critical equipment groups. AMGs have been published for different groups of power equipment including electrical switchgear [33], transformers, power distribution equipment [34], MCC [35] and other equipment such as battery chargers, stationary batteries, inverters and uninterruptible power supplies (UPS), and HV, MV, and LV cables.

In these documents various stressors and aging mechanisms are discussed as well as failure modes. Typical stressors in nuclear plants environment are high or low temperature, radiation, humidity, and contaminants, and these factors are electrical, mechanical, chemical, thermal, or electrochemical in nature. Stressors acting over time produce aging mechanisms that ultimately can cause component degradation. Typical aging mechanisms for electrical equipment include wear, lubricant deterioration, corrosion, and so on. Operational demands, environmental conditions, failure data, and industry operations and maintenance history should always be considered to determine the significance of the electrical equipment aging mechanisms.

Effective management of aging mechanisms is discussed in these guidelines, among them common maintenance, inspection, testing and surveillance techniques, or programs. An overview of the technical issues and recommended action to resolve these issues identified in AMGs for various types of electrical equipment are shown in Table 8.1. These technical issues may be of concern and the guidelines identify potential resolution strategies. The relatively small number of identified issues indicates a generally effective set of industry maintenance programs for the electrical components evaluated.

The guidelines for electrical switchgear define commonly used aging management actions: periodic visual inspection, measurement of various component properties (such as electrical resistance or contact tolerance), adjustment, operability

TABLE 8.1
AMG and Technical Issues for Electrical Equipment

Type of Equipment	Technical Issues	Resolution	AMG
Electrical switchgear	Overcurrent trip devices, lubrication practices, switchgear in “harsh” environments and/or subject to a high number of operating cycles may warrant additional attention.	Review and evaluate adequacy of existing maintenance and surveillance programs and alter if necessary.	SAND93-7027
Power and distribution transformers	Insulation, insulating fluid, bushing contamination, transformers in “harsh” environments and/or subject to a high number of operating cycles may warrant additional attention	Review and evaluate adequacy of existing maintenance and surveillance programs and alter if necessary.	SAND93-7068
Motor control centers	MCCB, MCCs in “harsh” environments and/or subject to a high number of operating cycles may warrant additional attention.	Review and evaluate adequacy of existing maintenance and surveillance programs and alter if necessary; perform root-cause analyses.	SAND93-7069
Battery chargers, inverters and uninterruptible power supplies	Inverter and UPS inspection frequency may need to be increased.	Increase inspection frequency of inverters and UPS to match that of chargers.	SAND93-7046
Stationary batteries	Seismic vulnerability of aged 1E lead-acid batteries may be a concern	Disassembly inspection of artificially aged and actual sample cells, seismic testing	SAND93-7071

Source: Adapted from *Aging Management Guideline for Commercial Nuclear Power Plants*, SAND93-7027, July 1993; SAND93-7068, May 1994; SAND93-7069, February 1994.

and functionality checks, lubrication, and component replacement. Less commonly used aging management programs include infrared thermography, acoustic vibration analysis, and component refurbishment.

Evaluation results demonstrated that existing nuclear plant maintenance activities and programs are largely effective at managing the aging of switchgear components. In a few instances additional actions may be taken to improve the effectiveness of the maintenance programs. For example, since overcurrent trip devices and other electrical devices appear caused a high percentage of the failures, an added consideration may be warranted for these units. Inadequate or degraded lubricant appears to have a strong correlation to instances of switchgear failure. Overhaul refurbishment may be required to effectively address lubricant degradation.

Switchgear components may require additional attention if they (1) are exposed to accident temperature, steam, or radiation conditions; (2) are exposed to temperatures in excess of 40°C (104°F) for extended periods; (3) are subject to a high number of operating cycles in relation to the manufacturer's design cyclic rating; or (4) are subject to environments containing high levels of dust or contaminants.

For power transformers commonly used aging management actions include visual inspection, periodic observation of temperatures and levels (where applicable), measurement of component properties (such as dielectric strength, oil viscosity, etc.). Degradation of transformer solid insulation and insulating fluid, as well as contamination of bushing external surfaces, appear to be closely related to the more damaging types of failures experienced by power and distribution transformers, and hence may warrant added consideration.

For MCCB, external operating handle mechanisms, and starter contactor auxiliary contact mechanisms caused comparatively large fractions of the total number of MCC component failures, and therefore may require additional consideration.

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Index

A

Acid, 148
 number, 321, 322
 neutralizers, 172
 in oil, 321, 322
 rain, 100, 148
AC power frequency HIPOT test, 315
Acoustic emission monitoring, 325–326
Acoustic surface wave, 340
Additive, 166, 168, 169, 171–173, 176
 stability, 201
Adhesion, 47, 148, 201
Aerosol, 101–103, 148
Aging Management Guideline (AMG), 273, 361
Air leveled tin, 92
 quality monitoring, 144–145
Airborne contaminants, 146
 ultrasonic detectors, 318
Air-insulated substations (AIS), 243, 244
AIS, *see* Air-insulated substations (AIS)
Alloy steel, 106, 107, 110, 111, 148
Aluminum, 286
 for conductor accessories, 109
 connectors, 286
 designing equipment using, 110
 in marine environment, 109
 overhead transmission lines, 109
 plating techniques on, 41
 precautions, 110
Aluminum plating
 choice of plating, 37, 38
 difficulties, 38–39
 in electrical industry, 37
 metals uses to, 39
 methods, 39–41
 standards, 47
 tin plating quality on Al, 41–45
Aluminum plating methods, 39
 plating classifications, 40
 plating techniques on Al, 41
 pretreatment by zincating, 40–41
AMG, *see* Aging Management Guideline (AMG)
ANSI/IEEE standards, 103, 241–242, 253–255
Anticorrosion properties, 13; *see also* Electroless nickel testing (EN testing)
 conditions, 13–14
 testing, 13

 analysis using SEM/EDS technique, 15
 TRS levels, 14
Antifoam
 additives, 172
 agent, 201
Antioxidants, *see* Oxidation inhibitor
Antipitting agent, 48, 148
Antiwear
 additives, 171, 172, 192, 201
 agents, 172
Apparent viscosity, 166
ASTM standards, 45, 223, 253–256
Atmospheric corrosion, 99, 149; *see also*
 Silver plating
 airborne contamination, 104–105
 indoor atmospheres, 99
 industrial atmosphere, 100
 marine atmosphere, 100
 rural atmospheres, 99–100
Atmospheric corrosion affecting factors
 active sulfur compounds, 103
 aerosol particles deposition, 102–103
 ammonia and derivatives, 104
 corrosive gases, 103
 hydrogen fluoride, 104
 inorganic chlorine compounds, 104
 nitrogen oxides, 103–104
 RH (Relative Humidity), 101
 sulfur oxides, 103
 temperature, 102

B

Base metal, 48, 126, 131, 134, 137, 149
Bath tub curve, 279–280
Bimetallic corrosion, *see* Galvanic corrosion
Bio-films, 232
Biological contamination, 232
Black rust, 134
Black zinc plating, 24
Blistering, 2, 42, 149
Bright plating, 49
 tin, 45
Brittle fracture, 149
 process, 233
Bus bar, 49
Bus bar insulation, 218
Bushing, 234
 capacitor, 234
 composite, 234

Bushing (*Continued*)

- condenser, 234–235
- failure mechanism, 296–297
- oil aging defects, 296
- Bushing failure, 295–296
 - in MV switchgear, 299–300
 - scenarios, 297

C

- Cable deterioration diagnostics, 358–359
- Cable in conduit (CIC), 237
- Cable insulating material aging
 - electrical treeing, 239
 - oil-paper insulated cables, 238
 - water treeing, 239
 - XLPE cable insulation degradation, 238, 239
- CableCURE fluid, 359
- CableWISE diagnostic technology, 359
- Capacitor bushings, 234
- CAT-1, *see* Clearance Assurance of Transmission (CAT-1)
- CB, *see* Circuit breaker (CB)
- CBM, *see* Condition-based maintenance (CBM)
- CCT, *see* Continuous current test (CCT)
- CD, *see* Current density (CD)
- Ceramics, 215
- Charring, *see* Tracking, 229, 230
- Chemical conversion coating, 25–26, 149
 - dip solutions, 120
- Chromium, 150
- Chromium IV, chromium III, 3, 25, 26
- Chromium-free varnish-preventative processes, 141
- CIC, *see* Cable in conduit (CIC)
- Circuit breaker (CB), 13, 166, 269, 270, 310
 - failure causes of, 235, 280–282
 - HV bushings in, 234
 - online monitoring techniques, 324
 - PD testing, 317–318
 - TEV, 318–319
 - ultrasonic detection of PD, 318
- Cleaning, 49
 - lubrication, 186
 - techniques for silver tarnish, 120–121
- Clearance Assurance of Transmission (CAT-1), 339
- CM, *see* Corrective maintenance (CM)
- Coating, 38, 39, 150
- Coating adhesion, 42, 43
- Coaxial cables, 215
- Combustible gases, 242
- Combustion products, 157
- Composite, 215
 - bushing, 234
 - plate, 50

- Composite insulators, 218; *see also* Non-ceramic insulator (NCI)
 - brittle fracture prevention, 234
 - stress corrosion cracking in, 233–234
- Compound-filled bushing, 234
- Condenser bushing, 234–235
- Condition-based maintenance (CBM), 348, 354; *see also* Time-based maintenance (TBM)
 - distribution power transformers, 356–358
 - HV switchgear, 354–355
 - MV switchgear, 355–356
 - power cable systems, 358–359
- Conductivity
 - electrical, 1–4, 7–8, 37, 50
 - thermal, 10, 38
- Conductor temperature measurements, 339
 - fiber-optic instruments, 340
 - SAW temperature monitoring, 340–341
- Conductors, 271, 274, 277
 - defects, 296
 - sag measurements, 339
- Conservator transformers, 294
- Consistency, 202
- Contact
 - fretting, 286–287
 - jamming, 298–299
- Contact resistance (CR), 1, 65, 110, 166, 286
- Contaminant, 202
- Contamination, 104, 251
- Continuous current test (CCT), 17
- Continuous galvanizing, 24
- Continuous temperature measurement; *see also* Fiber-optic technology
 - electronic temperature sensors, 329
 - IR noncontact temperature sensors, 328–329
- Conversion coating, 26, 50, 150
- Conversion Zinc plating, 25
 - color variability, 25–26
 - corrosion resistance, 25
 - cost issue, 26
 - drop test, 26
 - self-healing properties, 26
- Cooling media, 243
- Copper
 - copper-nickels, 107
 - corrosion, 107
 - plating, 150
 - strip corrosion, 150
 - underplating, 74
- Copper-to-aluminum connection
 - corrosion protective compound for, 89–90
 - protection, 88–89
- Corona, 225
 - carbon tracks on insulation board, 226
 - destructive nature, 225–226

- in switchgear, 227
- tracking, 226–227
- unusual weathering pattern, 228
- white powder/dust residue formed, 226
- Corrective maintenance (CM), 347
- Corrosion, 99–104, 150, 202, 286
 - copper, copper alloys, 107
 - creep, 75
 - crevice, 151
 - fatigue, 150
 - rate, 151
 - resistance, 151
 - silver, 110, 117
 - sulfuric, 111, 116
 - tin, 128–129
 - zinc, 130–131
- Corrosion Sunflower, 15, 17
- Corrosive environment effect
 - aluminum and aluminum alloys, 108–110
 - carbon steels, 106
 - copper and copper alloys, 107–108
 - iron, 106
 - nickel and nickel alloys, 108
 - stainless steels, 107
- Corrosive sulfur analysis, 241
- CR, *see* Contact resistance (CR)
- Critical humidity level, 101
- Cupronickels, *see* Copper-nickels
- Current density (CD), 50, 116
- Current-carrying components, 352

D

- DC, *see* Direct current (DC)
- DC HIPOT test, 313
 - usage, 313–314
 - XLPE MV cables, 314
- DC IR test, 327
- Demulsifiers, 173
- DES, *see* Disconnectors and Earthing switches (DES)
- Detergent, 51, 172, 202
- Detrimental process effect
 - contact resistance, 94
 - copper–tin IMC, 92
 - Cu–Sn IMC, 93–94
 - fretting, 94
 - fretting corrosion, 94–95
- DGA, *see* Dissolved gas analysis (DGA)
- Dielectric
 - breakdown, 257
 - composite materials, 217
 - constant, 257
 - dissipation factor/tan delta measurement, 357
 - oil, 239, 262
 - strength, 202, 241, 257
 - tests, 257

- Dielectric Withstanding Voltage test (DWV test), 19
- DIN standards, 255
- Direct current (DC), 20, 313
- Discharge dissipation factor (DDF), 312
- Disconnect switches (DS), 284
- Disconnectors and Earthing switches (DES), 294
- Dissimilar metals, 86
- Dissipation factor, 261
- Dissolved gas analysis (DGA), 240, 323, 356
- Distributed fiber-optic temperature sensing, 330–331
- Distributed temperature sensing (DTS), 340
- Distribution electrical equipment lubrication, 165, 166, 178
 - charts, 200
 - cleaning, 186
 - as corrosion protection, 184
 - of electrical contacts, 188
 - failure modes, 189–193
 - in field, 187
 - as fretting corrosion protection, 180, 181, 183
 - lubricants choice, 187
 - lubrication product change, 188
 - OEM specifications, 188
 - penetrating oil, 186–187
 - principles, 179
 - troubleshooting, 187
- Distribution equipment, life expectancy for electrical equipment lifetime estimation, 269–270
 - overloading, 270–271
 - temperature, 271–272
- Distribution lines, *see* Transmission lines
- Distribution power transformers, 356
 - diagnostic technique levels, 356–357
 - transformer health index (THI), 357–358
- Double insulation, 257
- Dropping point, 167, 190
- Dry
 - coating powder, 248
 - corrosion, 152
 - type bushing, 235
- DS, *see* Disconnect switches (DS)
- DTS, *see* Distributed temperature sensing (DTS)
- DWV test, *see* Dielectric Withstanding Voltage test (DWV test)

E

- EC, *see* Electrical conductor (EC)
- EDS, *see* Energy-dispersive x-ray spectroscopy (EDS)
- EIM, *see* Electrical insulating material (EIM)
- EIS, *see* Electrical insulation system (EIS)

- Electrical
 - machines, 245
 - stresses, 275
 - systems insulators, 215
 - tree, 239
- Electrical breakdown, 224
 - during electrical flashover, 225
 - electrical stress, 225
 - in insulation, 224–225
- Electrical conductor (EC), 109
- Electrical enclosures, 278
 - IEC standard, 245
 - indoor nonhazardous locations, 246
 - materials used for, 248
 - NEMA standard, 245
 - outdoor nonhazardous locations, 247
 - paint for, 245–253
 - powder coating for, 245–253
- Electrical equipment aging, 272
 - aged residential electrical equipment, 276–277
 - aging factors, 272–273
 - aviation, 273
 - CB failure causes, 280–282
 - chemical industries, 274
 - conductors aging, 277
 - dominant failure characteristics of, 284
 - electrical stresses, 275
 - factors, 276
 - failure modes and rates, 278–288
 - inadequate maintenance, 284
 - insulation aging, 277
 - natural effects, 276
 - NEC, 276
 - nuclear facilities, 273
 - oil refining industries, 274
 - overhead power transmission, 274
 - power plant, 274–275
 - residential equipment, 275–276
 - in rural/agricultural applications, 277–278
- Electrical equipment corrosion protection, 137
 - alternate plating, 140
 - chromium-free varnish-preventative processes, 141
 - conversion treatment, 140–141
 - lubrication, 142–143
 - metallic coatings, 137–138
 - paints, 138
 - polymeric coating, 138, 139
 - silver plating thickness, 139–140
 - silver protection from corrosion, 139
 - VCI, 142
 - zinc-plated steel protection, 141–142
- Electrical equipment failure
 - CBs with service voltage, 288
 - CIGRÉ surveys, 289–290
 - DES failure causes, 294
 - failure rates, 289
 - GIS, 288
 - GIS failure causes, 290–293
 - on high-voltage equipment, 288–289
 - SF₆ CBs failure causes, 293–294
 - types, 289
- Electrical equipment life expectancy
 - based on stress tests, 270
 - CB, 269
 - HV bushings, 269
 - lifetime estimation, 269
 - overloading, 270–271
 - temperature, 271–272
- Electrical equipment maintenance
 - CBM, 348, 354–356
 - CM, 347
 - in nuclear industry, 361–363
 - PdM, 348
 - PM, 347
 - RCM, 348–349
 - TBM, 347, 349
 - water-damaged electrical equipment, 360–361
- Electrical equipment overloading, 270
 - circuit breakers, 270
 - conductors, 271
 - transformers, 270
 - transmission cable, 271
- Electrical equipment physical conditions, 310;
 - see also* Transmission electrical equipment physical conditions
 - insulation condition assessment, 317–324
 - online monitoring, 323–326
 - parameters defining, 310–311
 - techniques for MV cable testing, 311–316
 - testing of HV bushings conditions, 326–327
- Electrical equipment thermal conditions, 327
 - continuous temperature measurement, 328–329
 - fiber-optic technology, 329–331
 - temperature measurement using thermography, 328
 - winding temperature monitoring, 331–332
 - wireless temperature monitoring, 332–336
- Electrical equipments, 309
 - current-carrying path, 272
 - electrical distribution equipment, 271
 - electrical machine, 272
 - estimated life of, 271, 272
 - heating requirements, 271
 - maintenance quality as failure cause, 287–288
 - overloading, 270–271
 - protective devices, 271, 272
 - temperatures, 271–272
 - UPS system, 271
- Electrical insulating material (EIM), 220, 223, 237, 257

- Electrical insulation, thermal limitation for
 - applying proper insulation, 222
 - electrical insulation material, 219
 - epoxy powder insulated MV bus, 220
 - IEEE Standards, 220
 - insulation temperature classes, 220
 - low-temperature class-Y insulation, 222
 - NEMA, 221
 - power electrical equipment, 219
 - synthetic resins, 221
 - temperature tolerance classes, 221
 - thermal performance, 223
 - TR limits, 222
 - Electrical insulation glossary
 - solid insulation, 256
 - insulating oil, 261
 - Electrical insulation standards and regulations
 - international, 254–256
 - national, 253–256
 - paints and coatings, 256
 - transformer oil, 256
 - Electrical insulation system (EIS), 220, 227, 257
 - Electrical preventive maintenance (EPM), 288
 - Electro-optic modulators (EO modulators), 325
 - EP, *see* Extreme Pressure
 - Electrogalvanizing, 24, 52
 - Electroless nickel (EN), 7, 9, 152
 - chemical composition, 9
 - corrosion resistance, 11
 - electrical resistivity, 11, 12
 - HPEN (high phosphorus EN), 9–12, 18
 - LPEN (high phosphorus EN), 9–12, 18
 - plating standards, 46
 - properties, 9, 10
 - thickness, 10–11
 - Electroless nickel immersion gold (ENIG), 33
 - Electroless nickel testing (EN testing), 13
 - anticorrosion properties, 13–17
 - electric properties, 17–18, 20, 21, 22
 - live electrical tests, 19, 20
 - precaution, 22–23
 - Electroless plating, 8, 52
 - Electrolyte, 52, 85
 - Electrolytic (galvanic) cell, 52, 114, 131
 - Electromagnetic acoustic transducer sensors (EMAT sensors), 338
 - Electromagnetic and radio-frequency interference (EMI/RFI), 330
 - Electronic temperature sensors, 329
 - Electroplated tin, 92
 - Electroplating, 1, 15, 52, 152
 - nickel plating, 6–8
 - silver plating, 1–4
 - tin plating, 4–6
 - zinc plating, 23
 - EMAT sensors, *see* Electromagnetic acoustic transducer sensors (EMAT sensors)
 - EMI/RFI, *see* Electromagnetic and radio-frequency interference (EMI/RFI)
 - Emulsifier, 173, 202
 - Emulsifying agent, 53
 - Emulsion, 52, 202
 - EN, *see* Electroless nickel (EN)
 - EN testing, *see* Electroless nickel testing (EN testing)
 - Energy
 - efficiency, 53
 - harvesting, 333
 - Energy-dispersive x-ray spectroscopy (EDS),
 - use for analysis, 15, 126
 - Engineering and trade publications and journals, 199–200
 - ENIG, *see* Electroless nickel immersion gold (ENIG)
 - Environmental control corrosion
 - protection, 143
 - air quality monitoring, 144–145
 - chemical and particulate filtration, 147
 - corrosion control technology, 145–146
 - direct gas monitoring, 145
 - electrical and electronic equipment
 - exposure, 143–144
 - temperature control, 147–148
 - Environmental cracking, 152
 - EO modulators, *see* Electro-optic modulators (EO modulators)
 - EPM, *see* Electrical preventive maintenance (EPM)
 - Epoxy, 257
 - Epoxy powder
 - bus bar insulation, 219
 - coating, 219
 - insulated MV bus, 220
 - Excitation current measurement, 357
 - External defects, 297
 - Extreme pressure (EP), 166
 - additives, 171, 172, 192, 203
 - lubricants, 203
- F**
- Fabry–Perot interferometers, 326
 - Failure, 152, 278–279, 289
 - proximate cause of, 280
 - rate, 279
 - Failure analysis, 152
 - Failure mode, 152, 279, 281
 - Feeder breaker, 301
 - FFA, *see* Furfural analysis (FFA)
 - Fiber-optic sensor, 326
 - Fiber-optic technology
 - distributed fiber-optic temperature sensing, 330–331

Fiber-optic technology (*Continued*)
 optical fiber sensing probe, 329–330
 for temperature measurement, 329
 winding temperature monitoring with,
 331–332
 Fiber-optic transceiver (FTR), 340
 Fiber-optic transmission conductor (FOTC), 340
 Fire point, 167, 203
 Flash point, 167, 203
 Forced outage, 279
 FOTC, *see* Fiber-optic transmission conductor
 (FOTC)
 Fretting, 94, 153
 Fretting corrosion, 94, 153
 of electrical contacts, 94, 95
 lubrication, 94, 95
 FTR, *see* Fiber-optic transceiver (FTR)
 Fuel, 100, 102, 103, 105, 153
 Furanic analysis, 241
 Furans in oil, 322
 Furfural analysis (FFA), 356

G

Galvanic
 cell, 53, 114, 131
 couple, 86, 91, 153
 current, 153
 series, 53, 86–87, 153
 Galvanic corrosion, 85, 86, 153, 185
 Cu-to-Al connection protection from, 88–90
 of Cu-to-Al connections, 87–88
 dissimilar metals, 86, 87
 electrical potential index, 86, 87
 electrolyte, 85
 precautions, 91
 recommendations, 91
 in steel connections with Al, 90–91
 Galvanized steel corrosion, 132–133
 in circuit breaker, 136–137
 environmental factors, 135
 pitting, 134–135
 rusting, 133–134
 zinc plating thickness, 135, 136
 Galvanizing, 53, 153
 hot-dip, 24
 process, 25
 standards, 46
 Gas-insulated substations (GIS), 243, 288, 309
 CIGRÉ surveys, 290–291
 CIS age, 291, 293
 CIS component, 292
 CIS voltage class, 292
 components age, 292
 components failure rate, 293
 environmental contribution in, 291
 failure causes, 290, 293

 failure discovery service conditions, 292
 failure modes, 291
 MF (Major Failure), 292–293
 Gas-insulated switchgear (GIS), 309
 Gaseous corrosion, 153
 Gassing, 53
 GCA, *see* General Condition Assessment (GCA)
 General Condition Assessment (GCA), 312, 313
 General corrosion, 153
 Geothermal liquids, 233
 Geothermal power plant (GTPP), 232
 GFCI, *see* Ground fault circuit interrupters
 (GFCI)
 GIS, *see* Gas-insulated substations (GIS);
 Gas-insulated switchgear (GIS)
 Glass, 218
 Glass electrode, 53
 Glass-reinforced plastic (GRP), 233
 Graphite, 169, 171, 183, 185, 188, 203
 Grease, 168, 203
 additives, 171–173
 composition, 169, 170
 thickeners, 170, 171
 Ground fault circuit interrupters (GFCI), 361
 Grounded specimen test (GST), 327
 GRP, *see* Glass-reinforced plastic (GRP)
 GST, *see* Grounded specimen test (GST)

H

Hand-held ultrasonic emission detector, 318
 Hexavalent chromium (CrIV), *see* Chromium,
 chromium IV, 3, 25, 26, 154
 High potential test (HP test), 19
 High potential withstand test (HIPOT withstand
 test), 312; *see also* Partial discharge
 diagnostics (PD diagnostics)
 AC power frequency HIPOT test, 315
 DC HIPOT test, 313–314
 VLF HIPOT test, 314–315
 High voltage bushings (HV bushings), 310
 in CB, 234
 DC IR test, 327
 failures, 235–236, 294–295
 hot-wire test for moisture, 327
 possible causes of failures, 235
 power-factor test, 326–327
 RIV test, 327
 testing oil for moisture, 327
 in transformers, 234
 types, 234–235
 High voltage transmission (HV transmission),
 216, 217
 High-end temperature insulation, 222
 High-voltage circuit breaker (HV CB), 350
 CIGRÉ surveys results, 289
 contact jamming, 298–299

- first survey results, 290
- mechanical linkage failure, 297
- trapped water in internal bolt holes, 297–298
- High-voltage electrical equipment failure, 294
 - bushings failure mechanisms, 296–297
- HV bushings failures, 294–295
- HV CBs failures, 297–299
- HV transformers failure mechanisms, 296–297
- HV transformers failures, 295–296
- High-voltage insulator coatings (HVIC), 251
- High-voltage switchgear (HV switchgear), 354
 - aging parameters, 355
 - CBM approach benefits, 354
- High-voltage test techniques—Partial discharge measurements, 318
- Hipot test, *see* High potential test (HP test)
- HIPOT withstand test, *see* High potential withstand test (HIPOT withstand test)
- Hot
 - corrosion, 154
 - cracking, 154
 - dip coating, 154
 - dipped tin, 92
 - oil dry out, 261
- Hot-dip
 - galvanizing, 24
 - tin plating, 32
- Hot-dip galvanized (HDG), 133
- Hot-wire test for moisture, 327
- HP test, *see* High potential test (HP test)
- HV bushings, *see* High voltage bushings (HV bushings)
- HV CB, *see* High-voltage circuit breaker (HV CB)
- HV power transformers, 282–283
 - bushing failure, 295, 296
 - failure mechanism, 295
 - winding insulation failure, 295, 296
- HV RTV coating, 251
 - aging, 252
 - fillers role in, 252–253
 - hydrophobicity loss, 253
- HV switchgear, *see* High-voltage switchgear (HV switchgear)
- HV transmission, *see* High voltage transmission (HV transmission)

I

- IEC standards, 245, 253, 254–255
- IEEE Standards, 220, 230, 252, 254, 256, 314
- IMC, *see* Intermetallic compound (IMC)
- In-service oil, limits for, 323
- Incompatibility (of lubricants), 173, 174
 - additives, 176
 - base oils, 174
 - thickeners, 174–176
- Index improver, *see* Viscosity modifier
- Industrial atmosphere, 154
- Industry standards organizations, 199
- Infant mortality failures, 280
- Infrared (IR), 328
 - noncontact temperature sensors, 328–329
 - thermography, 357
 - thermometry, 335
- Inhibitor, 54, 154, 204, 261
- Inorganic
 - fillers, 252
 - materials, 215
 - zinc-rich paint, 154
- Insulating material environmental aging, 231
 - biological contamination, 232
 - insulation deterioration, 231–232
 - insulators corrosion, 232
 - insulators in transmission lines, 232–233
 - pollution deposit composition, 233
 - stress corrosion cracking in, 233–234
- Insulating media
 - using air as, 244–245
 - insulating oil, 239–242
 - sulfur hexafluoride insulating and cooling media, 243–244
 - using vacuum as, 244–245
- Insulating oil, 239, 262
 - aging of transformer oil, 240–241
 - CB, 240
 - oil switches, 240
 - transformer oil, 239–240
 - transformer oil thermal and electrical faults, 241–242
- Insulation level, 258
- temperature classes, 220
- Insulation condition assessment; *see also* Electrical equipment physical conditions
 - oil condition diagnostics, 319–324
 - PD diagnostics, 317–319
- Insulation resistance (IR), 258, 326, 357
- Insulator, 215, 217
 - corrosion, 232
 - dielectric composite materials, 217
 - failure, 302–303
 - silicone rubber, 218
 - thermal degradation of, 222–223
 - thermal endurance of, 222
 - in transmission lines, 232–233
- Insulator thermal degradation, 222
 - ASTM Standard D2304, 223
 - electrical insulation material
 - thermal performance, 223
 - RTI, 222
 - thermal class of, 221
 - thermal endurance, 222
 - uses losing insulating properties, 223
- Intermetallic compound (IMC), 31, 64

Internal porcelain surface aging, 296
 International standards for solid
 insulation, 254–255
 IR, *see* Infrared (IR); Insulation resistance (IR)

L

Life extension technique, 349
 CBM, 354–356
 periodic lubrication of power circuit
 breaker, 351–352
 power circuit breaker maintenance, 349–351
 refurbishment, 352–353
 TBM, 349
 LIOS monitoring system, 341
 Liquid insulator, 216
 Low-oil-capacity, *see* Oil-minimum
 Low-temperature class-Y insulation, 222
 Low-voltage (LV), 13
 power electrical equipment failure, 284–285
 power transformers, 282
 Low-voltage circuit breaker (LV CB), 350
 Low-voltage electrical equipment failure, 299
 CBs' clusters and bushings degradation, 300
 LV switchboard failure, 303–305
 Metal-Clad switchgear failures, 302–303
 MV power cables failure, 303
 MV switchgear and bushing failures in,
 299–300
 MV switchgear failures, 300–302
 severe corrosion degradation, 300
 Low-voltage switchboard failure, 303
 control wiring short circuit, 304–305
 damaged and undamaged bus bars, 304
 failed LV switchboard, 304
 finger clusters and stabs, 304
 Lubricant, 155, 165, 204
 application, 188–189
 durability, 185–186
 evaluation, 179–183
 field testing, 184
 galvanic corrosion, 185
 grease, 168
 incompatibility, 173–176
 informational sources, 198–200
 manufacturers, 199
 oil, 167
 shelf life, 178
 silicones, 169
 solid, 169
 storage conditions, 177
 synthetic oils, 167–168, 169
 temperature limits, 176–178
 Lubrication failure mode
 causes, 189–190
 CB failures, 193, 194
 contaminants in lubricant, 191–192
 grease deterioration, 192–193
 lubricant composition and wrong lubricant
 amount, 191
 lubricants incompatibility, 193
 MV switch overheating, 194–198
 thermal limitations, 190–191
 wrong lubricant choice, 190
 Lubricity, 204
 LV, *see* Low-voltage (LV)
 LV CB, *see* Low-voltage circuit breaker
 (LV CB)

M

Major failure (MF), 129, 289
 Material insulation in electrical industry
 bus bar shrouds and boots, 219
 composite insulators, 218
 dielectric composite materials, 217
 electrical breakdown in, 224–225
 of electrical conductors, 218
 environmental aging of, 231–234
 EPDM, 218
 epoxy powder-coated bus bar insulation, 219
 5–35 kV bus, 219
 glass, 218
 glass-reinforced plastic insulation, 218–219
 HV system, 216
 inorganic materials, 215
 life in electrical stress, 224–230
 multiple insulating materials, 216
 NCI, 215
 organic insulating materials, 216–217
 PCB, 216
 polymer insulators, 215
 porcelain insulators, 217
 silicone rubber, 218
 suspended wires, 217
 temperature limitations for switchgear
 assembly, 223–224
 thermal degradation of insulators, 222–223
 thermal limitation for electrical insulation,
 219–222
 thermoplastic material, 216
 thermosetting epoxy powders, 219
 working and environmental conditions, 217
 Materials insulation in power equipment
 electrical insulation, thermal
 limitation, 219–222
 material insulation, in electrical industry,
 215–219
 for switchgear assembly, 223–224
 thermal degradation, 222–223
 Matte finish (mat finish), 3, 5, 6, 24, 36, 41,
 45, 55
 MC switchgear, *see* Metal-clad switchgear
 (MC switchgear)

- MCC, *see* Motor control centers (MCC)
- MCCB, *see* Molded case circuit breaker (MCCB)
- Mean time to failure (MTTF), 333
- Mechanical
- filter, 155
 - linkage failure, 297
 - stress, 69
- Medium voltage (MV), 19
- power electrical equipment failure, 284–285
 - power transformers, 282
- Medium voltage cable (MV cable), 237, 258, 303; *see also* Electrical equipment
- physical conditions
 - choosing diagnostics, 316
 - HIPOT withstand tests, 313–315
 - online monitoring techniques, 324
 - PD diagnostics, 315–316
 - PD-OL, 325
 - techniques for testing physical conditions, 311–312
 - testing technique comparison, 312–313
- Medium voltage circuit breaker (MV CB), 115, 350
- Medium-voltage electrical equipment
- failure, 299
 - bushing and switchgear failures, 299–300
 - CBs' clusters and bushings
 - degradation, 300 - corrosion degradation, 300
 - LV switchboard failure, 303–305
 - metal-clad switchgear failures, 302–303
 - power cable failure, 303
 - switchgear failures, 300–302
- Medium-voltage switchgear (MV switchgear), 283; *see also* High-voltage switchgear (HV switchgear)
- arcing, 301
 - component defect, 301
 - design errors, 301
 - failures, 283–284, 300, 301
 - flashover, 301
 - irreversible damage, 356
 - overheating, 301–302
 - temperature monitoring uses, 355
 - water condensation, 301
 - WTMS installation, 356
- Metal whiskers on plating, 26
- cadmium, 36
 - characteristics, 29
 - environmental factors, 29
 - growth conditions, 27, 28
 - gold, 36
 - historical account, 29–30
 - tin, 31–33
 - zinc, 36, 37, 105
- Metal-clad cable, 258
- Metal-clad switchgear (MC switchgear), 223
- corona in, 227
 - insulator failure, 302–303
 - lack of maintenance failure, 302
 - old circuit breaker failure, 302
 - thermal limits for insulating materials, 224
- Metallic
- coatings, 137–138
 - vapor, 245
- MF, *see* Major failure (MF)
- mf, *see* minor failure (mf)
- MG set, *see* Motor–generator set (MG set)
- MFG, *see* Mixed flowing gas (MFG)
- Microbiologically influenced corrosion, 156
- Microelectronic components, 216
- Mineral oil, 167, 169, 180–183, 204
- compatibility, 174
 - transformer oil, 239
 - transformer oil standards, 256
- Mining cable, 258
- minor failure (mf), 289
- Mixed flowing gas (MFG), 14
- Moisture, 156
- absorption, 258
 - content, 241
- Molded case circuit breaker (MCCB), 281, 349–350
- Moly (molybdenum disulfide, MoS₂), 169, 182, 187, 188, 204
- Motor control centers (MCC), 273, 360
- Motor–generator set (MG set), 55
- MTTF, *see* Mean time to failure (MTTF)
- Multigrade oil, 204
- Multiple insulating materials, 216
- Multiple testing techniques, 65
- MV, *see* Medium voltage (MV)
- MV cable, *see* Medium voltage cable (MV cable)
- MV CB, *see* Medium voltage circuit breaker (MV CB)
- MV switchgear, *see* Medium-voltage switchgear (MV switchgear)
- ## N
- National standards for paints and coatings, 256
- NCI, *see* Non-ceramic insulator (NCI)
- Neutral salt spray (NSS), 25
- Neutralization number, *see* Acid—number
- Nickel plating, 6, 156; *see also* Silver plating
- applications, 7
 - physical properties, 7–8
 - standards, 46
 - thickness, 8
- Nickel underplating, 74
- advantages, 74, 76
 - aging behavior comparison, 82–84

Nickel underplating (*Continued*)
 corrosion creep inhibitor, 84
 diffusion barrier, 74–75, 84–85
 for gold plating, 84
 improves wear resistance, 75
 increases corrosion resistance, 75
 Ni–Sn intermetallics formation, 82
 plating process, 80
 pore-corrosion inhibitor, 84
 precautions, 76–77
 preventing intermetallics formation, 75
 SEM/EDS metallographic
 analysis, 81, 82
 testing techniques, 81
 thickness, 76
 for tin plating on aluminum, 80
 for tin plating on copper, 77
 Nickel-plated copper, 8
 Non-ceramic insulator (NCI), 215, 233
 Nonconductive boards, 216
 Nonsolid dielectric materials, 215–216
 North American standards for solid
 insulation, 253–254
 NOX, *see* Oxides of nitrogen (NOX)
 NSS, *see* Neutral salt spray (NSS)
 Nuclear industry, electrical equipment in
 aging mechanisms, 362
 AMG guidance, 361, 362
 evaluation results, 363
 stressors, 361
 switchgear components, 363
 technical issues for, 362

O

OCB, *see* Oil circuit breaker (OCB)
 OEM, *see* Original equipment manufacturer
 (OEM)
 OHTL, *see* Overhead transmission lines (OHTL)
 acids in, 321, 322
 diagnostic techniques, 322–323
 dissolved gases in, 319–320
 furans in, 322
 immersed bushing, 235
 leakage sump, 262
 Oil, 167, 204
 pass, 262
 power factor in, 322
 reclaiming, 262
 reconditioning, 262
 regeneration, 262
 ring, 205
 spray nozzle, 262
 treatment, 262
 water in, 321, 323
 water valve, 262
 Oil circuit breaker (OCB), 240, 262
 Oil condition diagnostics, 262, 319; *see also*
 Partial discharge diagnostics
 (PD diagnostics)
 dissolved gases in oil, 319–320
 online monitoring, 323–324
 power factor of transformer oil, 322
 techniques, 322–323
 water and acids and furans in oil, 320–322
 Oil-filled bushing, 235
 Oil-impregnated paper-insulated bushing, 235
 Oil-minimum, 240
 Oil-paper insulated cables, 238
 Oiliness, 205
 Oiliness enhancers/lubricity additives, 173
 Online monitoring; *see also* Electrical
 equipment physical conditions
 analysis types, 324
 measurement devices, 323
 techniques for PD, 324–326
 of transformer oil conditions, 323
 Operations and maintenance manuals, 198
 Optical fiber sensing probe, 329–330
 Optical PD detection, 324
 Organic insulating materials, 216
 Organic materials, *see* Composite
 Organic Solderability Preservative (OSP), 33
 Original equipment manufacturer (OEM), 17,
 351–352
 OSP, *see* Organic Solderability Preservative (OSP)
 Overhead transmission lines (OHTL), 109,
 233, 336
 aging process, 337
 combined monitoring solutions, 341
 conductor sag measurements, 339
 conductor temperature measurements,
 339–341
 EHV, 337–338
 energized conductor temperature, 336
 EPRI projects, 338
 high-temperature operation, 337
 monitoring joints and conductors
 temperature, 338
 parameters, 338–339
 Overheating, 328
 Overvoltage, 55
 Oxidation, 55, 156, 205, 242
 inhibitor, 172, 201, 205
 stability, 167, 205
 Oxides of nitrogen (NOX), 156
 Ozone cracking, 255

P

Pad-mounted equipment, 248
 Paint for electrical enclosures, 245
 ASTM standard D1654, 251
 blisters in, 250

- failed powder coating, 250
- HV RTV coating, 251–253
- materials, 245–246
- mechanical defects, 250
- metallic coating, 249
- national standards for, 256
- nonuniform wetting, 250
- paint type selection criteria, 246–247
- properties, 249
- SS testing, 251
- steel panel corrosion, 251
- techniques of applying to metal panels, 247–249
- types, 245–246, 249
- Paint type selection criteria, 246
 - conditions, 246
 - materials used for, 248
 - mild conditions, 247
 - moderate conditions, 247
 - outdoor nonhazardous locations, 247
 - types and properties, 249
- Paints, 138
- Paper insulation, 237
- Paper-insulated bushing, 235
- Paraffinic, 205
- Partial discharge (PD), 227, 357
 - activity, 303
 - damage on cast resin CB spout, 228
 - within HV cables, 229
 - in HV/MV insulation, 229
 - internal, 299
 - in paper-insulated HV cables, 230
 - porcelain, 229
 - protracted, 227
 - repetitive discharge event, 229
 - solid insulating materials, 229
 - surface degradation, 299
 - in switchgear, 230
 - tracking on CB insulation, 231
- Partial discharge diagnostics (PD diagnostics), 312, 315, 317–318; *see also* Oil condition diagnostics
 - detection using transient earth voltages, 318–319
 - effect on insulation, 317–318
 - monitoring with fiber-optic technology, 325–326
 - offline, 316
 - online, 315
 - types, 312
 - ultrasonic detection, 318
- Partial Discharge monitoring, Online with Location (PD-OL), 325
- Passive devices, 334
- Passive wireless temperature sensors, 335
- Patina, 133, 157
- PD, *see* Partial discharge (PD)
- PD diagnostics, *see* Partial discharge diagnostics (PD diagnostics)
- PD-OL, *see* Partial Discharge monitoring, Online with Location (PD-OL)
- PdM, *see* Predictive maintenance (PdM)
- Peeling, 55, 67–69, 82–83
- Periodic maintenance (PM), 347
- pH, 54, 55, 157
- Photovoltaic elements, 334
- Pit, 133, 134, 56
- Pitting, 95, 110, 134, 136, 137, 157
- Pitting factor, 157
- Plating
 - range, 56
 - testing standards, 47
- PM, *see* Periodic maintenance (PM)
- Polarization index (PI), 357
- Pollutants, 233
- Polymer, 259
- Polymer insulator, 215, 231
- Polymeric coating, 138, 139
- Polymeric insulators; *see also* Non-ceramic insulator (NCI)
- Polypropylene, 259
- Polyvinyl chloride (PVC), 139, 219, 259
- Porcelain, 229
 - insulators, 217
- Porcelain dry-type bushings, 235
- Pore corrosion, 75
- Pour point, 167, 205
- Pour-point depressants, 173
- Powder coating, 157
- Powder coating for electrical enclosures, 245; *see also* Paint for electrical enclosures
 - applying to metal panels techniques, 247–249
 - ASTM standard D1654, 251
 - blisters in, 250
 - failed powder coating, 250
 - HV RTV coating, 251–253
 - materials, 245–246
 - mechanical defects, 250
 - metallic coating, 249
 - national standards for, 256
 - nonuniform wetting, 250
 - paint type selection criteria, 246–247
 - specifications for pad-mounted equipment, 250
 - SS testing, 251
 - steel panel corrosion, 251
 - types, 245–246, 249
- Power cable insulation, 236
 - cable insulating material aging, 238–239
 - electrical insulation materials, 237
 - loose core screens, 238
 - in nuclear industry applications, 237

Power cable insulation (*Continued*)
 paper insulation, 237
 paper-impregnated insulation, 237–238
 Power cable systems, 236, 275, 311, 358
 cable deterioration diagnostics, 358–359
 CBM and life extension, 359
 in nuclear industry applications, 237
 uses, 237
 Power circuit breaker maintenance; *see also*
 Condition-based maintenance (CBM)
 HV CBs, 350–351
 LV CBs, 350
 MCCBs, 349–350
 MV CBs, 350
 periodic lubrication, 351–352
 SF₆ gas circuit breakers, 351
 Power connector failure
 aluminum connectors, 286
 contact fretting, 286–287
 corrosion, 286
 electrical equipment failures, 285
 major failure-contributing causes, 286
 stress relaxation, 287
 Power factor of oil, 322
 Power plant, 274–275
 Power transformer, 275
 Power transformers failure, 282–283
 Power-factor test, 326–327
 Power-limited circuit, 259
 Predictive maintenance (PdM), 348
 Proximate cause, 281
 Pumpability, 167, 205
 PVC, *see* Polyvinyl chloride (PVC)

R

Radio-influence-voltage test (RIV test), 326, 327
 RCM, *see* Reliability-centered maintenance (RCM)
 Reactive metal, 158
 Reconditioning, 352–353
 Rectifier transformers, 282
 Red Plague Control Plan (RPCP), 115
 Red rust (RR), 25, 133
 Red-plaque corrosion, 113
 RPCP, 115
 sacrificial corrosion, 114
 Reduction of Hazardous Substances (RoHS), 33, 72
 Reflow tin, 92
 Refurbishment, 352–353
 Relative humidity (RH), 14, 100, 101, 158, 230
 Relative temperature index (RTI), 222
 Reliability-centered maintenance (RCM), 348–349
 Resin-bonded bushing, 235
 RH, *see* Relative humidity (RH)

RIV test, *see* Radio-influence-voltage test (RIV test)
 RoHS, *see* Reduction of Hazardous Substances (RoHS)
 Room temperature vulcanization (RTV), 251, 259
 coating, 251
 fillers role in, 252–253
 global applications, 252
 HVIC, 251
 hydrophobicity loss, 253
 IEEE developed guide, 252
 OHTL, 252
 RTV insulation, aging of, 252
 track resistant additives, 252
 RPCP, *see* Red Plague Control Plan (RPCP)
 Rubber, 259
 Rust, 133, 158
 Rust/corrosion inhibitors, 172

S

Sacrificial
 coating, 158
 corrosion, 114
 layer, 248
 protection, 57
 Sagometer, 339
 Saline water, 158
 Salinity, 158
 Salt spray (SS), 11, 131, 132
 testing, 251, 259–260
 ASTM-B-117 test procedure, 158
 SAW, *see* Surface acoustic wave (SAW)
 Scanning electron microscopy (SEM),
 used for analysis, 15, 124, 158
 SEM, *see* Scanning electron microscopy (SEM)
 SF₆, *see* Sulfur hexafluoride (SF₆)
 SF₆ insulation, *see* Sulfur hexafluoride
 insulation (SF₆ insulation)
 SHC, *see* Synthetic hydrocarbons (SHC)
 Shear stability, 167
 Shelf life, 159, 177
 Silica filler (SiO₂ filler), 252
 Silicon rubber (SIR), 232
 Silicones, 167–169, 180
 Silver plating, 1, 159; *see also* Nickel plating
 nickel underplate uses, 2–3
 physical properties, 1
 standards, 45
 technical characteristics, 2
 thickness, 2
 types, 3–4
 Silver plating corrosion, 110
 copper bus corrosion with, 116, 117
 quality on sulfuric corrosion, 116

red-plaque corrosion, 113–115
 silver tarnish, 111–112
 silver whiskers, 113
 sulfuric corrosion, 111
 tarnishing, 111
 thickness effect, 116
 underplating corrosion, 115–116
 Silver tarnish, 111–112, 117
 cleaning techniques, 120–121
 contact electrical resistance, 117–118
 current load and mechanical load effect, 119
 thickness, 118–119
 Silver underplating, 74
 Silver whiskers, 113, 121–122
 chemical composition, 126–127
 cleared factors, 127
 environmental factors, 122
 failures in electrical equipment, 123, 124
 morphology, 124, 125, 126
 native silver wires, 128
 plating factors, 122–123
 visual appearance, 123, 124, 125
 SiO₂ filler, *see* Silica filler (SiO₂ filler)
 SIR, *see* Silicon rubber (SIR)
 Slumpability, 167
 Soil dust, 232
 Solid dielectric
 cables, 238
 materials, 215
 Solid insulation
 international standards for, 254–255
 North American standards for, 253–254
 organic insulating materials, 216
 SS, *see* Salt spray (SS)
 Stress relaxation, 287
 Stress-corrosion cracking (SCC), 107, 159
 Sulfur hexafluoride insulation
 (SF₆ insulation), 243
 cooling media, 243
 decomposition of, 243–244
 gaseous products, 243
 as greenhouse gas, 244
 insulation properties, 243–244
 solid decomposition products, 243
 Sulfur hexafluoride (SF₆), 243
 CB failure, 293–294
 gas circuit breakers, 351
 major use of, 244
 Sulfuric corrosion, 111
 Surface acoustic wave (SAW), 334
 sensors, 335
 technology, 335–336
 temperature monitoring, 340–341
 Surface discharge, 226, 253
 Suspended wires, 217

Switchgear, 310, 311
 online monitoring techniques, 324
 PD detection in, 325
 PD testing, 317–318
 TEV, 318–319
 ultrasonic detection of PD, 318
 Switchgear assembly, temperature limitations
 for IEEE standard for MC
 switchgear, 223
 thermal limits for insulating materials in, 224
 Switching devices, 279
 Synthetic, 168, 169
 Synthetic hydrocarbon (SHC), 168, 206
 Synthetic lubricant, 206
 Synthetic oils, 167–168

T

Tackiness agents, 173
 TAN, *see* Total acid number (TAN)
 Tank-type oil, 240
 Tarnish, 58, 111
 TBM, *see* Time-based maintenance (TBM)
 Temperature rating, 260
 Temperature rise (TR), 18, 88, 173, 222, 272, 309
 Temperature tolerance classes, 221
 Testing oil for moisture, 327
 TEV, *see* Transient Earth Voltages (TEV)
 TEV technology and ultrasonic detection (UltraTEV), 325
 Thermal
 conductivity, 206
 diagnostics, 333
 stability, 206
 Thermocouple cable, 260
 Thermoelectric elements, 334
 Thermogalvanic corrosion, 159
 Thermoplastic, 260
 Thermoplastic material, 216
 Thermoset, 259, 260
 Thermosetting epoxy powders, 219
 Thermosetting insulation material, 216
 THI, *see* Transformer health index (THI)
 Threshold limit value (TLV), 14
 Time-based maintenance (TBM), 347, 349
 Tin blight, *see* Tin pest
 Tin disease, *see* Tin pest
 Tin leprosy (*Lèpre d'étain*), *see* Tin pest
 Tin pest, 70
 alloying metals, 70–71
 electrical connector failure, 72
 lead-free alloying metals, 71, 72
 RoHS impact, 72–73
 Tin plating, 4
 bright, 45, 49
 matte, 3, 5, 6, 24, 36, 41, 45, 55

- Tin plating (*Continued*)
 - properties, 4–5
 - thickness, 5–6
 - Tin plating corrosion, 128, 129
 - tin oxidation, 129
 - tin reaction with gases, 129
 - Tin plating performance, 63
 - accelerated aging study, 65–66
 - adhesion test, 66
 - connection overheating, 69–70
 - fretting corrosion, 64
 - IMC, 64
 - lubrication, 63–64
 - precautions, 63
 - thermal deterioration mechanisms, 68–69
 - thermal shock test, 66–68
 - tin pest, 70–73
 - tin-plated Al bus bars, 64–65
 - Tin plating quality on Al, 41, 43
 - adhesion test, 42, 43
 - Alstan techniques, 41
 - copper–bronze composition, 43, 44
 - thermal shock test, 42
 - thickness, 43
 - Tin plating standards, 45–46
 - Tin whisker mitigation techniques, 31
 - adding lead, 31–32
 - conformal coating, 32
 - hot-dip tin plating, 32
 - lead-free solders, 33
 - non-tin plating and coating, 32–33
 - pure tin finishes, 33
 - underplating, 31
 - TLV, *see* Threshold limit value (TLV)
 - Total acid number (TAN), 241, 263
 - TR, *see* Temperature rise (TR)
 - Tracking, 218, 226, 229, 279, 299, 300
 - Transducer, 340
 - Transformer health index (THI), 356, 357–358
 - Transformer oil, 239, 240, 262
 - aging of, 240–241
 - ANSI/IEEE standards, 241
 - dissolved gases in, 242
 - electrical faults, 241–242
 - international standards for, 256
 - mineral transformer oil, 240
 - national standards for, 256
 - oil temperatures, 242
 - oil-minimum, 240
 - online monitoring of, 323–324
 - oxidation, 242
 - power factor of, 322
 - sampling, 322
 - soluble hydrocarbon gases, 242
 - tank-type oil, 240
 - tests, 240–241
 - thermal and electrical faults, 241, 242
 - transformer oil thermal, 241, 242
 - Transformers, 270, 310
 - HV bushings in, 234
 - PD testing, 317–318
 - TEV, 318–319
 - turns-ratio measurement, 357
 - ultrasonic detection of PD, 318
 - Transient Earth Voltages (TEV), 318–319
 - Transmission cable, 271, 274
 - Transmission electrical equipment physical conditions; *see also* Electrical equipment thermal conditions
 - OHTL, 336–341
 - online condition monitoring, 336
 - Transmission equipment, life expectancy for electrical equipment lifetime estimation, 269–270
 - overloading, 270–271
 - temperature, 271–272
 - Transmission lines, 232–233
 - Trapped water in internal bolt holes, 297–298
 - Treeing, 229, 239
 - Trees
 - carbonized, 230
 - electrical, 238, 239, 275
 - water, 238, 239, 275, 303
- ## U
- UHF, *see* Ultra-high frequency (UHF)
 - Ultra-high frequency (UHF), 325
 - UltraTEV, *see* TEV technology and ultrasonic detection (UltraTEV)
 - Underground cable circuits, 325
 - Underground residential distribution (URD), 237
 - Underplating, 73
 - copper, 74
 - mitigating role, 73–74
 - nickel, 74
 - silver, 74
 - Unfilled type bushing, 235
 - Ungrounded-specimen test (UST), 327
 - Uninterruptible power supply (UPS), 271, 361
 - UPS, *see* Uninterruptible power supply (UPS)
 - URD, *see* Underground residential distribution (URD)
 - UST, *see* Ungrounded-specimen test (UST)
- ## V
- Vacuum circuit breakers (VCB), 245
 - Vapor corrosion inhibitors (VCI), 142, 147, 160
 - VCB, *see* Vacuum circuit breakers (VCB)
 - VCI, *see* Vapor corrosion inhibitors (VCI)
 - Very low frequency (VLF), 312–313

VI, *see* Viscosity index (VI)
Vibration harvesters, 334
Video Sagometer, *see* Sagometer
Viscosity, 160, 166, 207
Viscosity grade, 207
Viscosity modifier, 173, 207
Viscosity index (VI), 166, 207
VLF, *see* Very low frequency (VLF)
VLF HIPOT test, 314
VOC, *see* Volatile organic compound (VOC)
Volatile organic compound (VOC), 160

W

Waste Electrical and Electronic Equipment (WEEE), 31
Wastewater Treatment Plant (WWTP), 19
Water
 content, 263
 in oil, 321
 tree, 239, 275, 303
Water-damaged electrical equipment, 360
 LV and MV breakers, 360–361
 switches and LV protective components, 360
 transformer exposure, 361
 wire or cable product exposure, 361
Weak mitigators, 80
Wear, 207
Wear-out, 280
Weather shed, 231
Weathering, 99
WEEE, *see* Waste Electrical and Electronic Equipment (WEEE)
Wet storage staining, *see* White Rust (WR)
Whisker index (WI), 79
Whisker mitigation levels, 34–36
Whiskers, 58
 silver, 121–127
 tin, 31–33
 zinc, 36–37
White rust (WR), 25, 131, 160
WHS, *see* Winding hot spot (WHS)

WI, *see* Whisker index (WI)
Winding
 insulation failure, 295–296
 temperature monitoring, 331–332
Winding hot spot (WHS), 331
Wireless temperature sensors, 333–334
Wireless temperature-monitoring system (WTMS), 332
 problems, 332–333
 with SAW sensors, 335–336
 structure and benefits, 332
 techniques, 334–335
 thermal diagnostics, 333
 wireless temperature sensors, 333–334
WR, *see* White rust (WR)
WTMS, *see* Wireless temperature-monitoring system (WTMS)
WWTP, *see* Wastewater Treatment Plant (WWTP)

Y

Yellow zinc plating, 24

Z

Zinc
 coating methods, 132
 corrosion, 130, 131
 electroplating, 23–24
 phosphate, 247
 plating, 160
 plating standards, 46
 whiskers, 36, 37, 105
Zinc galvanization process
 continuous galvanizing, 24
 electrogalvanizing, 24
 galvanizing process, 25
 hot-dip galvanizing, 24
Zinc plating corrosion, 130, 131
 in dry air, 130
 white rust (WR) on zinc, 25, 131, 132
Zinc-rich primers, 247

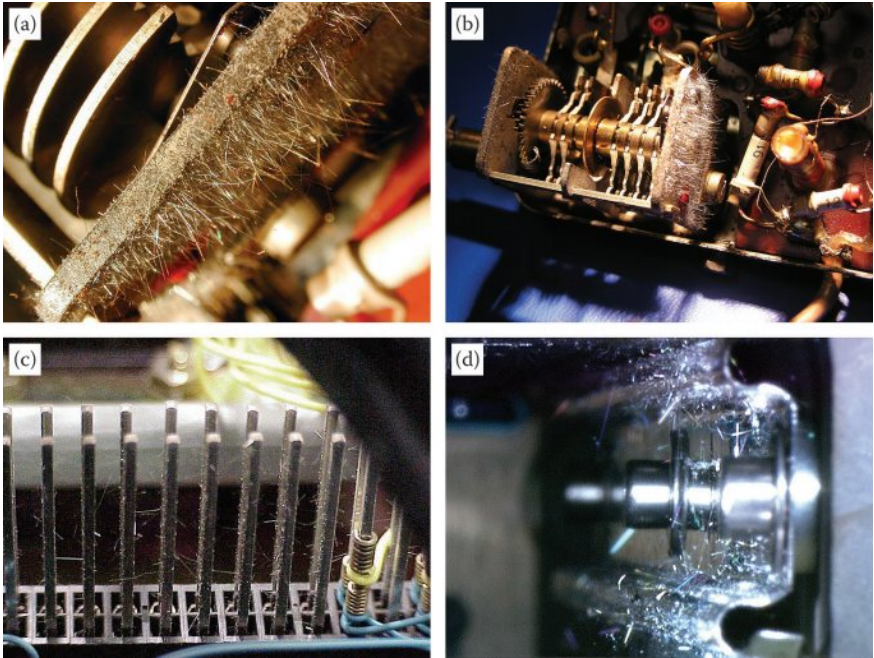


FIGURE 1.6 Tin whiskers. (a) On tin-plated housing on variable air capacitor built in 1959, found in 2006; (b) on a 1960s era variable air capacitor; (c) on connector pins; and (d) on printed circuit card guides from Space Shuttle. (Courtesy of the NEPP Program, nepp.nasa.gov/whisker/.)

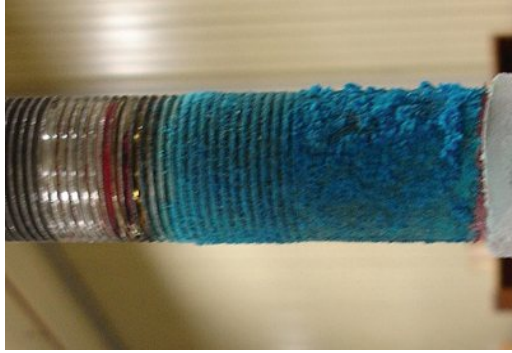


FIGURE 3.1 Green and blue corrosion of bushing stud made of bare copper.

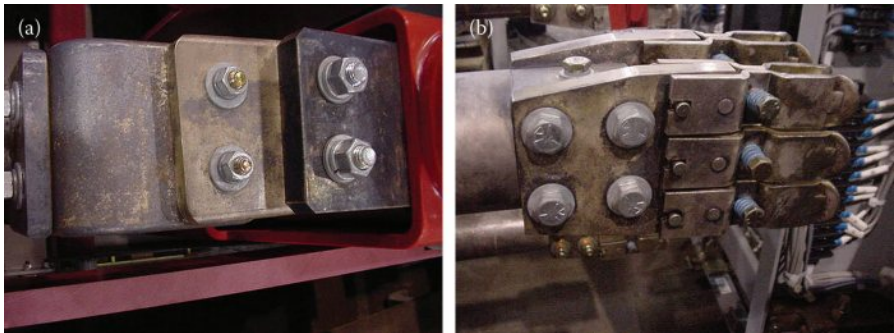


FIGURE 3.2 Tarnished silver plating on copper bus after various periods of service at industrial facility (a) and of storage at a manufacturing facility (b).



FIGURE 3.3 Heavy silver plating tarnish on copper bus after several months in service at an industrial facility.



FIGURE 3.4 Finger cluster of corroded breaker after 2 months of service in a paper mill facility (pulp processing mill).



FIGURE 3.5 Silver-flash plated copper bus after being shipped overseas. (Courtesy of Finishing.com, Online. Available: <http://www.finishing.com/280/03.shtml>; the picture is taken by Steve Whatley.)

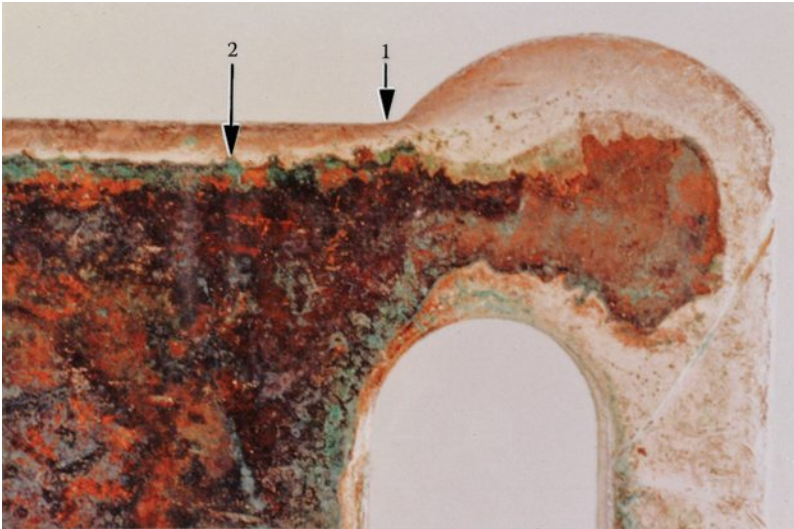


FIGURE 3.6 Underplating corrosion: silver plating on the contact surface (1), and corroding copper under silver plating (major component—copper carbonate hydroxide) (2) (4× magnification). (From *Under Coating Corrosion of Silver Plated Copper in a Circuit Breaker*, Online. Available: <http://www.corrosionlab.com/Failure-Analysis-Studies/20034.under-coating-silver-plated-copper.htm>, courtesy of Corrosion Testing Laboratories, Inc., Newark, DE. With permission.)

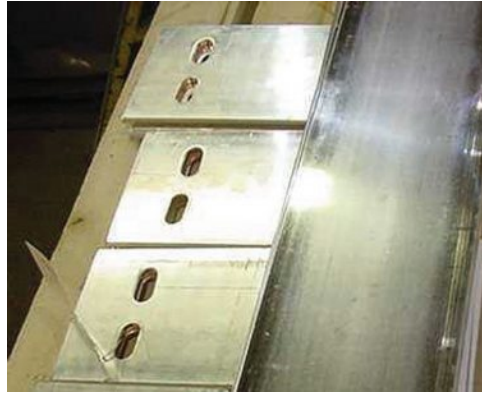


FIGURE 3.7 Copper bus with silver flash stored for 12 months at a manufacturing facility with clean environment.



FIGURE 3.8 “Blue” and “green” corrosion of copper with silver flash on bus bars (a) and plate (b).



FIGURE 3.9 Images of the parts of the CB failed due to heavy corrosion and growth of silver whiskers: finger cluster (a) and arc chute (b).



FIGURE 3.14 Corrosion silver whiskers and natural silver wires (a, b, c, and d): is there a difference?



FIGURE 3.16 Pitting corrosion on galvanized steel.

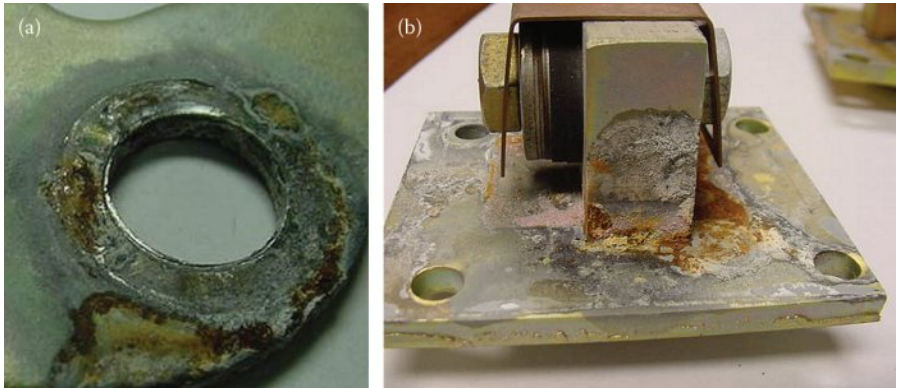


FIGURE 3.17 White rust and red rust on the mounting plates (a) and around the opening in steel plates (b).

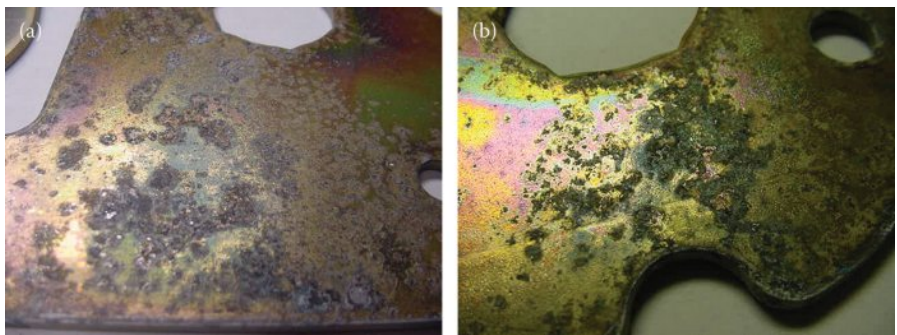


FIGURE 3.18 Pitting corrosion found on the surfaces of steel parts: black and brown pits (a) and green pits (b).

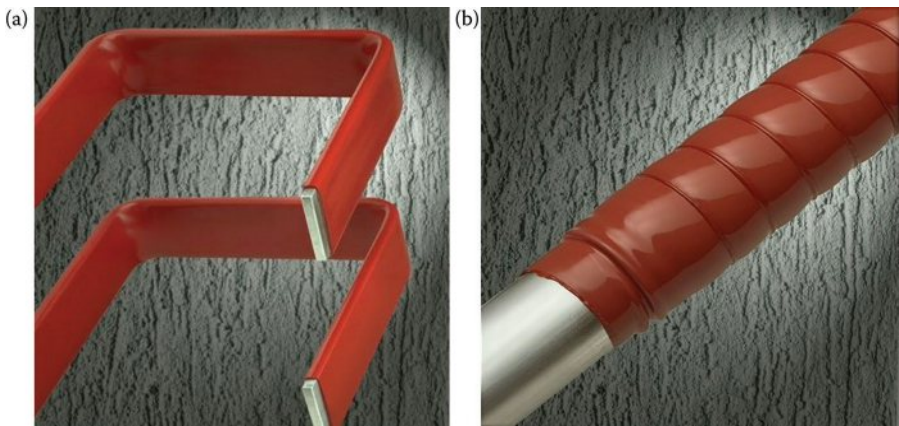


FIGURE 5.2 A 5–35 kV bus with heat shrinkable tubing (a) and tape (b). Users should independently evaluate the suitability of the insulating material pictured above for their particular use.) (From TE Connectivity, Online. Available: http://energy.te.com/index.asp?act=page&pag_id=2&pri_id=5&pls_id=29&prf_id=135&prr_parent=968. Photographs reprinted with permission.)

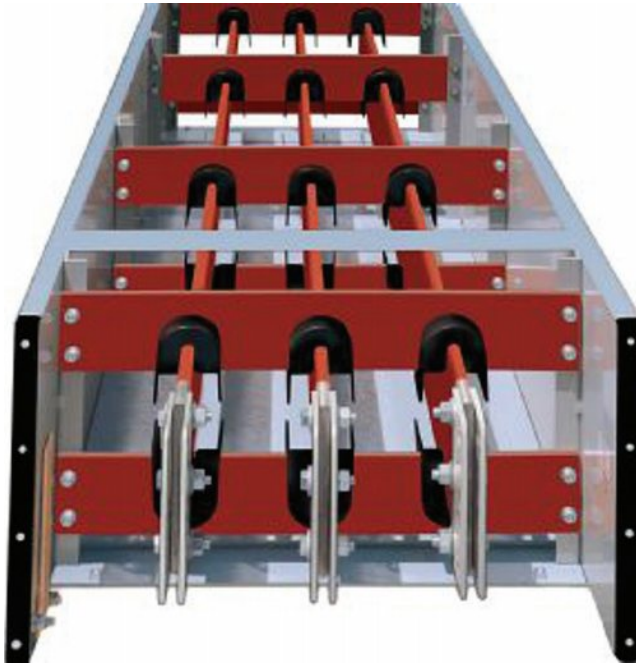


FIGURE 5.3 Epoxy powder insulated MV bus. (From Park Electric Company Busway, Online. Available: <http://www.parkdetroit.com/What-We-Do/Busways>. With permission.)

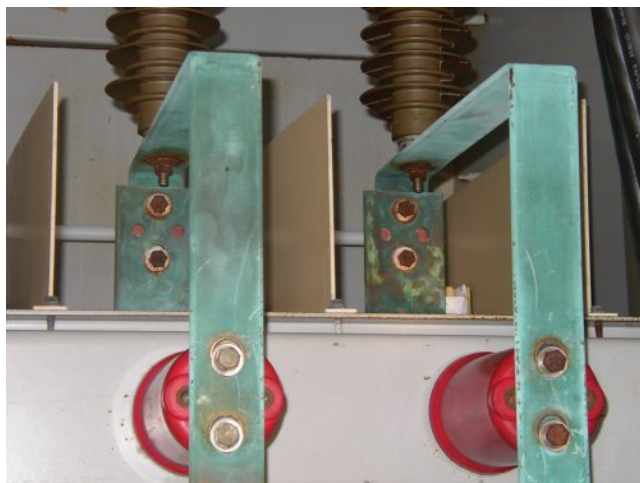


FIGURE 5.6 Unusual weathering pattern on 13 kV copper bus under attack by corona produced nitric acid. (From Brady J. *Corona and Tracking Conditions in MC Switchgear Case Studies*, Online. Available: http://www.irinfo.org/articles/article_8_1_2006_Brady.pdf. With permission.)

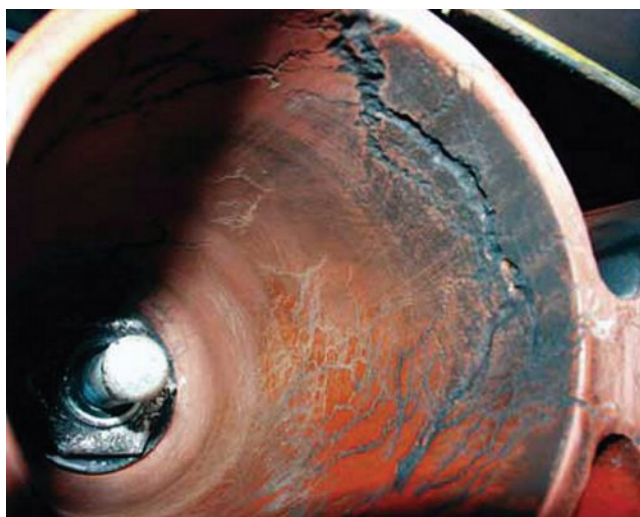


FIGURE 5.7 PD damage on a cast resin CB spout. (From Neil D. *Why PD measurement can pay dividends*, Online. Available: http://www.pennenergy.com/index/power/display/8315670195/articles/power-engineering-international/volume-18/Issue_3/features/Why_partial_discharge_measurement_can_pay_dividends.html. With permission.)

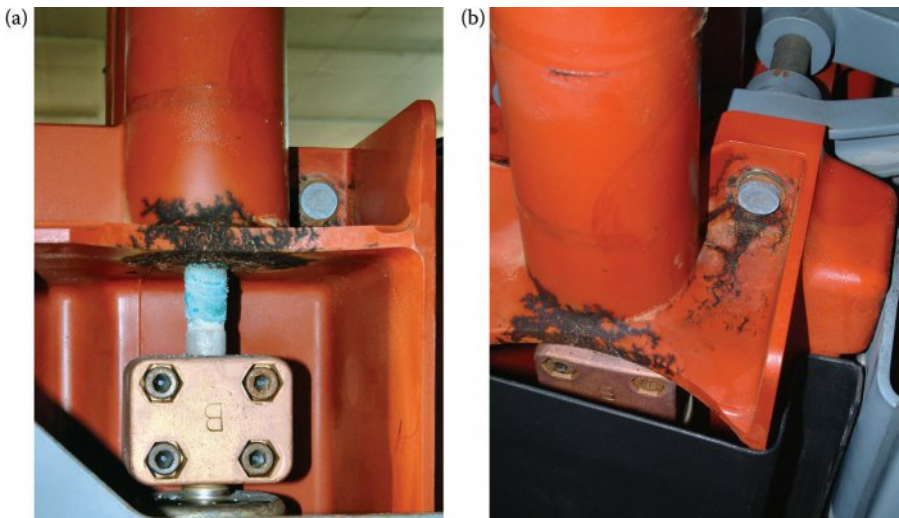


FIGURE 5.8 Partial discharge tracking on CB insulation (a and b). (From Davies N. and Goldthorpe S. Testing distribution switchgear for partial discharge in the laboratory and the field, *Proceedings of 20th International Conference on Electricity Distribution*, CIRED 2009, Prague, 8–11 June 2009, paper 0804, Online. Available: http://www.cired.be/CIRED09/pdfs/CIRED2009_0804_Paper.pdf. With permission.)

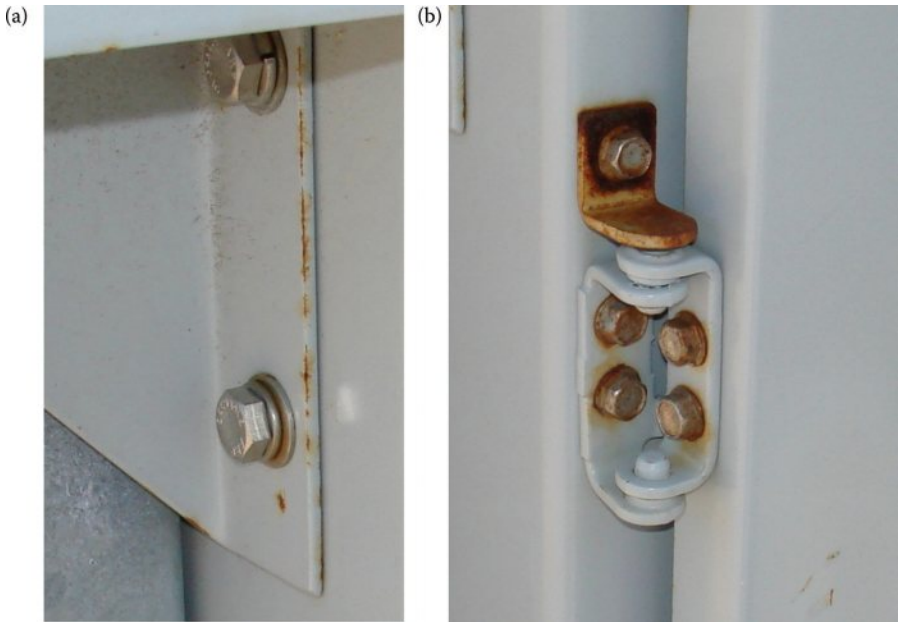


FIGURE 5.10 Corrosion of steel panels (a), brackets and bolts (b) of CB enclosure caused by coating failure.

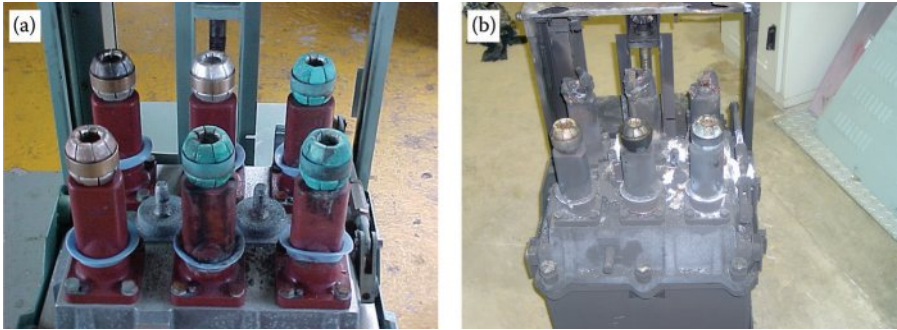


FIGURE 6.3 Degradation of the CB clusters and bushings. (From C. van Heerden and A. Rogerson. *Bushing failures in medium voltage switchgear*, 2009 AMEU Convention, Online. Available: <http://www.ameu.co.za>. With permission.)

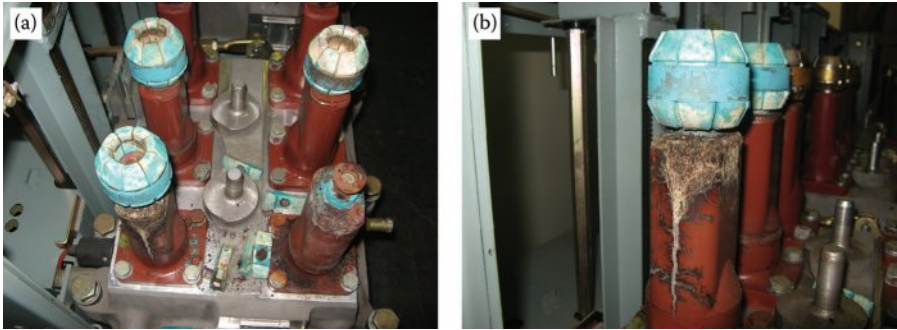


FIGURE 6.4 Severe corrosion degradation of the clusters (a) and tracking on the bushings (b). (From C. van Heerden and A. Rogerson. Bushing failures in medium voltage switchgear, 2009 Convention, Online. Available: <http://www.ameu.co.za>. With permission.)

Electrical Power Transmission and Distribution Aging and Life Extension Techniques

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