

# **Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems**

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Schweitzer Engineering Laboratories, Inc., Pullman, WA 99163  
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18 17 16 15 14 13 12 11 10                      1 2 3 4 5

ISBN: 978-0-9725026-3-4

Publisher's Cataloging-in-Publication Data  
(Provided by Quality Books, Inc.)

Modern solutions for protection, control, and monitoring of  
electric power systems / edited by Hector J. Altuve  
Ferrer, Edmund O. Schweitzer, III.

p. cm.

Includes bibliographical references and index.

ISBN-13: 978-0-9725026-3-4

ISBN-10: 0-9725026-3-7

1. Electric power systems. 2. Electric power systems  
--Protection. 3. Electric power systems--Control.  
I. Altuve Ferrer, Hector J. II. Schweitzer, Edmund O.

TK1001.M63 2010

621.31

QBI10-600113

[www.selinc.com](http://www.selinc.com)

# Dedication

This book is dedicated to Carole Lowinger, with grateful appreciation for her many years of instructing SEL engineers in the fine art of writing clearly and concisely. Carole's work has been a vital contribution to this book. Carole's unfailing sense of humor and good cheer make her a pleasure to work with and to know.

# Acknowledgements

This book is the result of a collective work. It reflects the cutting-edge technology developed by many SEL engineers. The book also extensively uses much of their technical literature, including technical papers, application guides, and instruction manuals. Some of these engineers directly contributed to the text while others reviewed the book and provided valuable improvements. Finally, many people contributed by enhancing the writing style, creating the figures, composing the book, and managing the book preparation process. We are deeply indebted to all of them.



# Table of Contents

Dedication.....	iii
Acknowledgements.....	iii
List of Figures.....	xvii
List of Tables.....	xxvii
Preface.....	xxix
<b>1 Looking to the Future.....</b>	<b>1</b>
1.1 Introduction.....	1
1.2 Time-Synchronized Measurements.....	1
1.3 Distribution Systems.....	2
1.4 Transmission Systems.....	3
1.5 Transformers.....	4
1.6 Buses.....	4
1.7 Generators.....	4
1.8 Wide-Area Systems.....	5
1.9 Communications.....	5
1.10 Information Processing.....	6
1.11 Cybersecurity.....	6
1.12 Reliability and Testing.....	6
1.13 Providing Complete Solutions.....	7
1.14 Asset Management.....	7
1.15 Call to Action.....	7
1.16 References.....	7
<b>2 Time-Synchronized Systems.....</b>	<b>9</b>
2.1 Introduction.....	9
2.2 Time-Synchronized Measurement Applications.....	9
2.3 Time Synchronization.....	10
2.4 Time-Synchronized Phasors.....	12
2.4.1 Synchrophasor definition.....	12
2.4.2 Phasor angle reference for power system networks.....	12
2.4.3 Synchrophasors provide power system state information.....	13
2.4.4 Phasor angle and frequency are indicators of power system dynamic performance.....	13
2.5 Combining Time-Synchronized Measurements With Protection, Control, and Monitoring.....	14
2.5.1 Advantages and architecture.....	14
2.5.2 Performance of synchrophasor measurements.....	15
2.5.2.1 Performance metrics.....	15
2.5.2.2 Visualizing synchrophasor measurements during fault and power swing conditions.....	16
2.5.2.3 Performance of synchrophasor measurements during faults.....	17
2.5.2.4 Performance of synchrophasor measurements during power swings.....	19
2.6 Processing Synchrophasor Information.....	20
2.6.1 Phasor data concentration.....	20
2.6.2 Synchrophasor-based protection, control, and monitoring.....	20
2.6.2.1 Using real-time synchrophasor processors for advanced applications.....	20
2.6.2.2 Using directly communicated PMcus.....	22

2.7	Synchrophasor Systems .....	22
2.7.1	Time sources.....	22
2.7.2	Phasor measurement devices.....	22
2.7.3	Synchrophasor processors .....	24
2.7.4	Communications networks .....	25
2.7.5	Application software .....	26
2.8	References.....	27

<b>3</b>	<b>Distribution System Protection, Automation, and Monitoring .....</b>	<b>29</b>
3.1	Introduction.....	29
3.2	Limitations of Traditional Overcurrent Protection .....	29
3.3	Modern Solutions for Distribution System Protection, Automation, and Monitoring .....	30
3.3.1	New abilities .....	30
3.3.2	More sensitive fault detection .....	30
3.3.3	Faster fault clearing .....	30
3.3.4	Faster service restoration.....	31
3.3.5	Higher reliability and lower cost .....	32
3.4	Negative-Sequence Overcurrent Protection .....	32
3.4.1	Negative-sequence overcurrent elements .....	32
3.4.2	Coordinating negative-sequence overcurrent elements with phase overcurrent elements .....	33
3.5	Directional Overcurrent Protection.....	35
3.5.1	Directional elements for phase fault protection.....	35
3.5.2	Directional elements for ground fault protection .....	35
3.5.2.1	Zero-sequence, current-polarized directional element .....	36
3.5.2.2	Negative-sequence, voltage-polarized directional element.....	36
3.5.2.3	Zero-sequence, voltage-polarized directional element.....	36
3.5.2.4	32Q and 32V element operation for ground faults.....	36
3.5.2.5	Selecting the optimal directional element .....	37
3.6	Improving Ground Fault Protection Sensitivity .....	38
3.6.1	Ungrounded systems .....	38
3.6.2	Resonant-grounded systems .....	39
3.6.2.1	Wattmetric directional element .....	39
3.6.2.2	Incremental conductance element .....	40
3.6.3	High-resistance grounded systems .....	40
3.6.4	Effectively and low-impedance grounded systems .....	41
3.6.4.1	Multigrounded systems .....	41
3.6.4.2	Single-point grounded systems .....	42
3.7	Effect of Load Current.....	42
3.7.1	Traditional backup sensitivity limitations .....	42
3.7.2	Increasing sensitivity for three-phase faults .....	42
3.7.3	Increasing sensitivity for phase-to-phase faults .....	42
3.7.4	Solving cold-load restoration current problems .....	43
3.7.5	Avoiding sympathetic tripping.....	43
3.8	Distributed Generation Considerations.....	43
3.8.1	Interconnection protection.....	43
3.8.1.1	Local-area islanding detection .....	44
3.8.1.2	Wide-area islanding detection .....	44
3.8.1.3	Complete interconnection protection .....	45
3.8.1.4	SEL multifunction relays provide interconnection protection .....	46
3.8.2	Distributed generation impacts utility system protection.....	46
3.8.2.1	Line protection .....	46
3.8.2.2	Automatic reclosing and synchronism checking.....	46
3.9	High-Speed Distribution System Protection.....	46
3.10	Reducing Arc-Flash Hazards.....	47
3.10.1	Methods for reducing arc-flash hazards .....	47
3.10.1.1	Avoiding the hazard area.....	47
3.10.1.2	Installing arc-resistant switchgear.....	47
3.10.1.3	Limiting the fault current .....	47
3.10.1.4	Improving protection schemes .....	47

3.10.2	Arc-flash protection .....	47
3.10.2.1	Arc-flash time-overlight element.....	48
3.10.2.2	Arc-flash overcurrent element .....	49
3.10.2.3	Event reports .....	49
3.10.2.4	Sensor location.....	49
3.11	Distribution Automation .....	49
3.11.1	Distribution automation objectives .....	49
3.11.2	Automatic throw-over schemes .....	50
3.11.3	Distribution network fast-restoration schemes .....	51
3.11.4	Centralized distribution automation systems .....	51
3.11.5	Examples of distribution protection and automation systems .....	52
3.12	Faulted Circuit Indicators.....	53
3.12.1	Benefits of faulted circuit indicators.....	53
3.12.2	Faulted circuit indicator applications.....	53
3.12.3	Combine faulted circuit indicators and relays for fast fault location.....	54
3.12.4	Other application considerations.....	54
3.12.5	Looking to the future.....	54
3.13	References .....	54
<b>4</b>	<b>Transmission Line Protection .....</b>	<b>57</b>
4.1	Introduction .....	57
4.2	Transmission Systems of Today and Tomorrow.....	57
4.3	Line Protection Principles .....	59
4.4	Directional Overcurrent Protection .....	60
4.5	Distance Protection .....	61
4.5.1	Basic principle.....	61
4.5.2	Distance protection schemes.....	62
4.5.2.1	Basic concepts.....	62
4.5.2.2	Reach settings .....	62
4.5.2.3	Time-delay settings.....	62
4.5.3	Distance element input signals.....	63
4.5.4	Mho distance elements.....	64
4.5.4.1	Digital product phase comparators .....	64
4.5.4.2	Mho characteristic derivation .....	64
4.5.5	Quadrilateral distance elements .....	66
4.5.5.1	Quadrilateral element characteristic .....	66
4.5.5.2	Reactance element .....	66
4.5.5.3	Resistance elements .....	67
4.5.5.4	Directional element.....	68
4.5.6	Adaptive polarization.....	68
4.5.7	High-speed elements .....	70
4.6	Sources of Distance Element Errors.....	72
4.6.1	Infeed effect .....	72
4.6.2	Fault resistance.....	73
4.6.3	Mutual coupling .....	75
4.6.4	Load encroachment .....	76
4.6.5	Effect of unfaulted phases.....	76
4.6.6	Coupling-capacitor voltage transformer transients .....	77
4.6.7	Loss-of-potential .....	78
4.7	Directional Comparison Protection.....	79
4.7.1	Basic schemes .....	79
4.7.1.1	Direct underreaching transfer trip.....	79
4.7.1.2	Permissive underreaching transfer trip .....	79
4.7.1.3	Permissive overreaching transfer trip .....	80
4.7.1.4	Directional comparison blocking.....	80
4.7.1.5	Directional comparison unblocking.....	80
4.7.2	Communications channels .....	80

4.7.3	Scheme comparison.....	81
4.7.3.1	Security and dependability .....	81
4.7.3.2	Speed and sensitivity .....	81
4.7.3.3	Complexity .....	83
4.7.4	Hybrid directional comparison scheme .....	83
4.8	Differential Protection .....	84
4.8.1	Communications channels and data alignment .....	84
4.8.2	Alpha-plane differential element.....	85
4.8.2.1	Representing power system conditions on the alpha plane.....	85
4.8.2.2	Alpha-plane differential element characteristic .....	86
4.8.2.3	Combining phase and sequence-component differential elements .....	87
4.8.3	Advanced differential protection for multiterminal lines.....	87
4.8.4	Combining differential and directional comparison protection in one relay.....	89
4.9	Phase Comparison Protection.....	89
4.10	Line Protection Sensitivity .....	91
4.10.1	System grounding.....	91
4.10.2	Relay sensitivity .....	91
4.10.2.1	Ground directional overcurrent element sensitivity .....	91
4.10.2.2	Ground distance element sensitivity .....	91
4.10.2.3	Ground differential element sensitivity.....	92
4.10.3	Power system unbalances .....	92
4.10.3.1	Unbalanced operating conditions .....	92
4.10.3.2	Unbalanced system elements .....	93
4.10.4	Instrument transformer accuracy.....	93
4.11	Series-Compensated Line Protection.....	94
4.11.1	Voltage inversion affects directional discrimination.....	94
4.11.2	Current inversion affects directional and differential discrimination.....	94
4.11.3	Series capacitors affect distance measurement.....	95
4.11.4	Directional comparison scheme security.....	96
4.12	Single-Pole Tripping.....	96
4.12.1	Faulted-phase identification .....	96
4.12.2	Single-pole open considerations.....	97
4.12.2.1	Distance elements.....	97
4.12.2.2	Directional overcurrent elements .....	97
4.12.2.3	Differential elements .....	98
4.12.3	Simultaneous faults .....	98
4.13	Power Swing Blocking and Out-of-Step Tripping .....	99
4.13.1	Impedance-based power swing detection.....	99
4.13.1.1	Power swing detection principle .....	99
4.13.1.2	Detecting faults occurring during power swings.....	100
4.13.1.3	Power swing blocking during the SPO period in SPT schemes.....	100
4.13.1.4	Application considerations.....	100
4.13.2	Swing-center-voltage method for power swing detection.....	100
4.14	Thermal Protection .....	101
4.15	Fault Locating.....	102
4.15.1	Single-ended methods .....	102
4.15.1.1	Simple reactance method .....	103
4.15.1.2	Takagi method.....	103
4.15.1.3	Modified Takagi method.....	103
4.15.2	Multiended method.....	103
4.15.2.1	Application to two-terminal lines.....	104
4.15.2.2	Application to multiterminal lines.....	104
4.16	References.....	104
<b>5</b>	<b>Transformer Protection and Monitoring.....</b>	<b>107</b>
5.1	Introduction.....	107
5.2	Innovations in Transformer Protection and Monitoring.....	107
5.3	Transformer Differential Protection .....	108
5.3.1	Operation principle.....	108

5.3.2	Current scaling, phase-shift compensation, and zero-sequence current removal .....	109
5.3.2.1	Current scaling .....	109
5.3.2.2	Transformer connections .....	110
5.3.2.3	Current phase-shift compensation .....	110
5.3.2.4	Zero-sequence current removal .....	111
5.3.3	Compensation for zero-sequence sources .....	112
5.3.4	Differential current caused by magnetizing inrush, overexcitation, and CT saturation .....	112
5.3.4.1	Magnetizing inrush currents .....	112
5.3.4.2	Transformer overexcitation.....	113
5.3.4.3	CT saturation.....	113
5.3.5	Discriminating internal faults from inrush and overexcitation conditions .....	113
5.3.5.1	Harmonic-based methods .....	113
5.3.5.2	Wave-shape recognition methods .....	114
5.3.6	Microprocessor-based transformer differential elements .....	115
5.3.6.1	Operation principle .....	115
5.3.6.2	Differential element .....	116
5.3.6.3	DC-ratio blocking logic .....	117
5.3.6.4	Relay-blocking logic.....	117
5.3.6.5	Adaptive differential element .....	118
5.3.6.6	Negative-sequence differential element.....	118
5.4	Restricted Earth Fault Protection .....	120
5.4.1	Traditional restricted earth fault protection .....	121
5.4.2	Microprocessor-based relays improve restricted earth fault protection.....	121
5.5	Transformer Overexcitation Protection.....	122
5.6	Transformer Overcurrent Protection .....	122
5.6.1	Transformer through-fault capability curves .....	123
5.6.2	Transformer overcurrent relay protection .....	123
5.7	Transformer Sudden-Pressure and Gas-Accumulation Protection.....	125
5.7.1	Sudden-pressure protection .....	125
5.7.2	Gas-accumulation protection .....	125
5.8	Combined Transformer and Bus Protection.....	126
5.9	Redundancy Considerations for Transformer Protection.....	126
5.10	Transformer Monitoring.....	127
5.10.1	Microprocessor-based IEDs perform transformer monitoring functions.....	127
5.10.2	Transformer thermal model .....	127
5.10.3	Insulation aging.....	130
5.10.4	Through-fault monitoring .....	130
5.10.5	Effect of through faults in transformer loss-of-life .....	131
5.10.6	Integration of nonelectrical monitoring devices .....	132
5.11	References .....	132
<b>6</b>	<b>Bus and Breaker-Failure Protection.....</b>	<b>135</b>
6.1	Introduction .....	135
6.2	Modern Solutions for Bus Protection.....	135
6.3	Bus Arrangements .....	136
6.4	Bus Protection Schemes .....	136
6.4.1	Differential overcurrent protection .....	137
6.4.2	High-impedance differential protection .....	138
6.4.3	Percentage differential protection .....	140
6.4.3.1	Basic concepts.....	140
6.4.3.2	Advanced bus differential protection.....	141
6.4.4	Partial differential protection .....	144
6.4.5	Zone-interlocked protection.....	144
6.4.5.1	Zone-interlocked, directional comparison blocking scheme .....	145
6.4.5.2	Zone-interlocked, simple blocking (fast bus-tripping) scheme .....	146
6.5	Breaker-Failure Protection .....	148
6.5.1	Impact of breaker-failure protection on power system stability .....	148
6.5.2	General considerations.....	148
6.5.3	Basic breaker-failure protection scheme.....	149

6.5.4	Breaker-failure protection scheme with consistent delay.....	149
6.5.5	Fast open-phase detectors.....	150
6.5.6	Fast-reset breaker-failure protection scheme.....	151
6.5.7	Breaker-failure scheme with alternate initiation logic .....	151
6.5.8	Use different breaker-failure times for multiphase and single-phase-to-ground faults.....	152
6.5.9	Breaker-failure application in multifunction relays .....	153
6.5.10	Breaker-failure tripping .....	153
6.6	Integrated Bus and Breaker-Failure Protection .....	154
6.6.1	Protection zone selection.....	154
6.6.2	Bus differential and breaker-failure protection tripping.....	156
6.7	References.....	156

## 7 Generator Protection and Monitoring.....159

7.1	Introduction.....	159
7.2	Modern Multifunction Generator Relays.....	159
7.3	Stator Fault Protection .....	159
7.3.1	Phase fault protection .....	159
7.3.2	Turn-to-turn fault protection.....	161
7.3.3	Ground fault protection .....	161
7.3.3.1	Generator grounding .....	161
7.3.3.2	Using the neutral voltage for protection.....	163
7.3.3.3	Using the third-harmonic voltage for protection.....	163
7.3.3.4	100 percent stator ground fault protection .....	164
7.3.3.5	Ground fault protection for low-impedance-grounded generators.....	164
7.4	Rotor Fault Protection.....	165
7.5	Abnormal Operation Protection.....	167
7.5.1	Stator thermal protection .....	167
7.5.2	Field thermal protection .....	168
7.5.3	Current unbalance protection .....	168
7.5.4	Loss-of-field protection .....	169
7.5.4.1	Effect of a loss of excitation on the generator and the power system.....	169
7.5.4.2	Protection schemes .....	169
7.5.4.3	Loss-of-field element setting considerations.....	170
7.5.5	Motoring protection.....	172
7.5.6	Overexcitation protection .....	173
7.5.7	Overvoltage and undervoltage protection .....	173
7.5.8	Abnormal frequency protection.....	174
7.5.8.1	Turbine abnormal frequency protection.....	174
7.5.8.2	Generator abnormal frequency protection.....	174
7.5.8.3	Underfrequency load shedding versus generator underfrequency protection.....	174
7.5.8.4	Underfrequency protection with SEL-300G and SEL-700G relays.....	174
7.5.9	Out-of-step protection .....	175
7.5.9.1	Single-blinder protection scheme.....	175
7.5.9.2	Double-blinder protection scheme .....	175
7.5.10	Inadvertent energization protection.....	176
7.5.10.1	Generator damage .....	176
7.5.10.2	Protection using other schemes .....	176
7.5.10.3	Protection using dedicated schemes.....	176
7.5.11	Backup protection.....	177
7.5.11.1	Voltage-supervised overcurrent elements .....	178
7.5.11.2	Distance elements.....	178
7.5.11.3	Backup protection for ground faults.....	179
7.6	Synchronism-Checking and Autosynchronizing Elements .....	179
7.7	P-Q Plane Based Generator Monitoring.....	180
7.8	SEL-300G Relay Application Solutions.....	180
7.9	References.....	181

<b>8</b>	<b>Wide-Area Protection, Control, and Monitoring</b>	183
8.1	Introduction	183
8.2	Assessing Substation State and Topology	183
8.2.1	Topology processor	184
8.2.2	Current processor	184
8.2.2.1	Current measurement normalization and consistency check	184
8.2.2.2	Kirchhoff's current law verification	184
8.2.2.3	Refining current measurements	184
8.2.3	Voltage processor	185
8.3	Determining Power System State	185
8.3.1	Traditional state estimation	185
8.3.2	Synchrophasor-based state determination	186
8.3.3	Remote measurement supervision	187
8.4	Detecting Power System Interarea Oscillations	188
8.4.1	Signal modal representation	188
8.4.2	Damping ratio	188
8.4.3	Signal-to-noise ratio	189
8.4.4	Identifying interarea oscillation modes	189
8.4.5	Modal-analysis-based system integrity protection scheme	190
8.5	Black-Start Validation and Paralleling of Islanded Generators With a Large System	190
8.6	Applying Synchrophasors to Predict Voltage Instability	192
8.7	Automatic Generator Shedding Using Synchrophasor Angle Measurements	193
8.8	Use Synchrophasors to Back Up Transmission Line Protection	196
8.8.1	Faulted-phase identification	196
8.8.2	Negative-sequence and zero-sequence current differential elements	196
8.8.3	Protection element performance	197
8.9	Distributed Bus Differential Protection	198
8.9.1	Protection zone selection	198
8.9.2	Current differential element	198
8.9.3	Application example of bus differential protection	199
8.10	Power Swing and Out-of-Step Detection Using Synchrophasors	199
8.10.1	Power swing detection	200
8.10.2	Out-of-step detection	200
8.10.3	Predictive out-of-step tripping	201
8.10.4	System integrity protection scheme for two-area power systems	201
8.11	Synchrophasor-Based Islanding Detection	204
8.12	System Integrity Protection Scheme Using MIRRORED BITS Communications	205
8.13	Load Shedding to Prevent Voltage Collapse	207
8.14	References	209
<b>9</b>	<b>Power System Communications</b>	211
9.1	Introduction	211
9.2	Communications System Overview	211
9.2.1	Pilot protection	211
9.2.2	Substation and distribution automation	211
9.2.3	Wide-area protection and control	211
9.2.4	SCADA and EMS	212
9.2.5	Security	212
9.2.6	Engineering access and maintenance	212
9.2.7	Example installation	213
9.3	Communications Channels	213
9.3.1	Channel capacity	213
9.3.2	Channel reliability	214
9.3.3	Channel availability	214
9.3.4	Propagation delay	214
9.4	Fiber-Optic-Based Communication	214
9.4.1	Optical fiber types and characteristics	215
9.4.2	Fiber-optic connectors and transceivers	215

9.4.3	Dedicated fiber-optic channels .....	216
9.4.3.1	SEL fiber-optic transceivers for 0–115 kbps applications .....	217
9.4.3.2	Fiber-optic-based remote I/O modules.....	218
9.4.3.3	Fiber-optic-based temperature measurement module .....	219
9.4.4	Shared fiber-optic channels .....	219
9.4.4.1	Fiber-optic multiplexers .....	219
9.4.4.2	SEL support for direct fiber-optic interface to multiplexers .....	220
9.4.4.3	SONET .....	221
9.4.4.4	Native Ethernet transport .....	221
9.4.4.5	Comparison between native Ethernet and SONET .....	222
9.4.4.6	SEL Integrated Communications Optical Network .....	222
9.5	Wireless Systems .....	223
9.5.1	Microwave.....	223
9.5.2	Narrow-band VHF/UHF radio .....	223
9.5.3	Spread-spectrum radio.....	224
9.6	Modern Communication-Based Protection .....	224
9.6.1	Communication-based protection schemes .....	225
9.6.2	Improving the reliability of communication-based protection.....	226
9.6.3	Communications standards.....	226
9.6.4	Environmental and performance standards .....	226
9.7	MIRRORED BITS Communications.....	226
9.7.1	Description .....	226
9.7.2	Security.....	227
9.7.3	Dependability .....	227
9.7.4	Channel performance monitoring.....	227
9.7.5	Implementation example .....	228
9.7.6	Logic processor .....	228
9.7.7	MIRRORED BITS tester .....	229
9.8	Ethernet Communication .....	229
9.8.1	Ethernet port speed and fiber-optic interface .....	229
9.8.2	Full-duplex operation and collision-free environment.....	229
9.8.3	IEEE 802.3x flow control.....	230
9.8.4	Priority queuing and VLAN support .....	230
9.8.5	Loss-of-link management.....	230
9.8.6	Remote monitoring, port mirroring, and diagnostics .....	231
9.8.7	LAN-based network protocols .....	231
9.8.8	Ethernet-based protection message standards .....	231
9.8.9	Ethernet-based SEL product portfolio.....	231
9.8.10	Ethernet radio .....	232
9.9	Future Trends.....	233
9.10	References.....	234

<b>10</b>	<b>Information Processing .....</b>	<b>237</b>
10.1	Introduction.....	237
10.2	Operations Technology and Information Technology.....	237
10.3	Integrated IED Networks.....	239
10.3.1	Communication makes IEDs informed and organized.....	239
10.3.2	Hierarchical levels of integrated IED networks .....	240
10.3.2.1	Process level.....	240
10.3.2.2	Unit level.....	240
10.3.2.3	Station level.....	240
10.3.2.4	Enterprise level.....	240
10.3.3	Serial networks and Ethernet local-area networks .....	240
10.3.4	Star, multidrop, and ring LAN configurations .....	241
10.3.5	SEL Best Practice Methods support serial and Ethernet LANs .....	242
10.3.6	SEL Best Practice Methods for protection, control, and monitoring networks.....	245
10.4	SEL Specialized IEDs Improve Data Processing .....	245
10.4.1	Categories of power system data.....	245
10.4.2	SEL IEDs provide specialized processing.....	246

10.4.3	SEL IED communication surpasses communication focused only on SCADA.....	247
10.4.4	SEL IEDs create situational awareness.....	248
10.4.5	SEL IEDs create apparatus data models .....	248
10.4.6	Migration to routable protocols reduces security and increases complexity .....	249
10.4.6.1	Message payload transparency .....	249
10.4.6.2	SEL protocols are purpose-built .....	250
10.4.6.3	Routing the nonroutable.....	250
10.4.6.4	Protecting transparent data and routable messages.....	250
10.4.6.5	Routing improves performance .....	250
10.4.6.6	SEL protocols provide optimal blend .....	251
10.5	SEL Increases LAN Functionality .....	252
10.5.1	SEL Best Practices based on scientific measures .....	252
10.5.2	Different networks require different information processors .....	252
10.5.3	Data processing .....	253
10.5.4	Automation functions.....	254
10.5.5	Network functions.....	254
10.5.6	Information notification and visualization.....	255
10.5.7	Other SEL advantages.....	255
10.6	Create Best-in-Class Networks .....	255
10.6.1	Modern communications methods satisfy IED network tasks.....	255
10.6.2	SEL ICON provides for new generation networks .....	257
10.7	Use IEC Standard 61850 Network Evaluation Methods.....	258
10.7.1	SEL designs for availability .....	258
10.7.2	SEL designs for performance.....	258
10.8	SEL IEDs Monitor, Decide, and Act.....	259
10.8.1	Separate protection and automation.....	259
10.8.2	Automate with networked SEL IEDs.....	260
10.8.3	SEL versatility.....	261
10.9	References .....	261
<b>11</b>	<b>Information Security .....</b>	<b>263</b>
11.1	Introduction .....	263
11.2	Important Security Tips.....	263
11.3	Attacker Profile and Motivation.....	264
11.3.1	Advantages of electronic attack methods.....	264
11.3.2	Groups that threaten the electric power infrastructure.....	264
11.3.2.1	Government-sponsored information warfare programs.....	264
11.3.2.2	Hostile organizations .....	264
11.3.2.3	Insiders.....	265
11.3.2.4	Hackers .....	265
11.4	Attack Techniques and Tools.....	265
11.4.1	Network reconnaissance .....	265
11.4.2	Active scanning.....	266
11.4.3	Exploiting vulnerabilities.....	267
11.4.3.1	Exploiting SCADA network vulnerabilities.....	267
11.4.3.2	Exploiting vulnerable user-login services.....	268
11.4.3.3	Exploiting vulnerable software or system users .....	269
11.4.4	Attack propagation.....	270
11.5	Prioritizing Electronic Security Risks in the Electric Power Industry .....	270
11.6	Defensive Technologies and Strategies.....	271
11.6.1	Electronic attack barriers .....	271
11.6.2	Defining the electronic security perimeter.....	272
11.6.3	Limiting access to protected networks.....	272
11.6.3.1	Choosing secure communications technologies .....	272
11.6.3.2	Implementing restrictive traffic filtering to isolate critical TCP/IP LAN segments.....	272
11.6.3.3	Using security settings in communications gateways to manage channel availability.....	273
11.6.4	Implementing strong cryptographic link security .....	273

11.6.5	Implementing strong, local electronic access controls in critical devices.....	275
11.6.5.1	Strong passwords.....	276
11.6.5.2	Password-based access control.....	276
11.6.5.3	Cryptographic access controls.....	277
11.6.6	Securing personal computers.....	277
11.7	Detecting and Responding to Electronic Attacks .....	277
11.8	References.....	279

## 12 Protection System Reliability and Testing.....281

12.1	Introduction.....	281
12.2	Reliability Concepts.....	281
12.2.1	Definitions and measures .....	281
12.2.2	Failure rates and patterns of failure.....	282
12.3	System Reliability Analysis Methods.....	282
12.3.1	Block diagram method .....	282
12.3.2	Fault-tree analysis method.....	283
12.3.2.1	Device failure rates and unavailabilities .....	283
12.3.2.2	Fault-tree construction.....	283
12.3.2.3	Advantages of fault-tree analysis .....	284
12.4	Improving Availability .....	285
12.4.1	Redundant protection systems.....	285
12.4.2	Design considerations for redundant protection systems .....	285
12.4.3	Aviation industry comparison .....	286
12.4.4	Advantages of redundant protection configurations.....	286
12.4.5	Effect of common-mode failures.....	287
12.5	Selecting Reliable Protective Relays.....	287
12.5.1	Designing products for quality and reliability.....	287
12.5.1.1	Designing for simplicity.....	287
12.5.1.2	Selecting reliable components.....	288
12.5.1.3	Analyzing designs for reliability .....	288
12.5.2	Thoroughly testing products before release .....	288
12.5.2.1	Real-time digital simulation testing .....	288
12.5.2.2	Highly accelerated life test extends operating margin .....	289
12.5.2.3	Type testing beyond standard requirements extends performance margin .....	289
12.5.2.4	Reliability test .....	289
12.5.3	Manufacturing for reliability .....	290
12.5.4	Using field data to increase product reliability.....	290
12.6	Relay Testing and Commissioning.....	291
12.6.1	Microprocessor-based relay self-tests .....	291
12.6.2	Additional microprocessor-based relay monitoring features .....	292
12.6.2.1	Loss-of-potential or loss-of-current detection features act as self-tests.....	292
12.6.2.2	Metering .....	292
12.6.2.3	Relay event data analysis detects problems .....	292
12.6.2.4	Exercising output contacts .....	293
12.6.3	Testing microprocessor-based relays .....	293
12.6.3.1	Type testing.....	293
12.6.3.2	Commissioning testing.....	293
12.6.3.3	Routine maintenance testing .....	294
12.6.3.4	Automated event retrieval .....	294
12.7	References.....	294

## 13 Substation Protection, Control, and Monitoring System Design.....297

13.1	Introduction.....	297
13.2	Design Objectives of Substation Protection, Control, and Monitoring Systems.....	297
13.2.1	Functional requirements .....	297
13.2.2	Design objectives.....	297
13.2.3	Benefits of system integration and automation .....	298

13.3	DC Control Power System Requirements for Substations.....	298
13.3.1	Battery monitoring features built into SEL relays .....	298
13.3.2	External battery monitoring systems.....	299
13.4	Protection System Redundancy.....	299
13.5	DC Logic Circuit Design.....	300
13.5.1	Circuit layout.....	300
13.5.2	DC system fault protection .....	301
13.5.3	Tripping/closing circuit design .....	302
13.5.3.1	Programmable logic simplifies the dc control circuits .....	302
13.5.3.2	DC circuit monitoring .....	304
13.5.3.3	Communications system monitoring .....	304
13.5.4	Auxiliary relays.....	305
13.5.4.1	Direct tripping.....	305
13.5.4.2	Close interlocking .....	306
13.5.4.3	Seal-in auxiliary relay function.....	306
13.5.4.4	Switching inductive dc circuits.....	306
13.5.5	Remote I/O modules .....	306
13.5.6	Targeting considerations.....	307
13.5.7	Manual control system design.....	309
13.5.7.1	Manual control system redundancy .....	309
13.5.7.2	Independent control pushbuttons .....	310
13.5.7.3	Control signal communications paths.....	311
13.5.7.4	Large operator controls provide redundancy for substation computer.....	311
13.5.8	Using communications links for critical protection and control functions .....	311
13.6	AC Sensing Circuit Design .....	313
13.6.1	Circuit design .....	313
13.6.2	Power system protection circuits .....	313
13.6.3	Metering circuits .....	313
13.6.4	Transient recording .....	314
13.6.5	Continuous monitoring of device measurements.....	314
13.7	Application of Test Switches .....	314
13.8	Design Documentation.....	314
13.8.1	Complete design documentation package.....	315
13.8.2	DC elementary (schematic) diagrams.....	315
13.8.3	Logic diagrams.....	316
13.8.4	Standards.....	317
13.9	Panel and Substation Control Enclosure Design.....	317
13.9.1	Purpose of a substation control enclosure.....	317
13.9.2	Protection, control, and monitoring panel design .....	318
13.9.3	Effects of integrated protection, control, and monitoring systems on enclosure design .....	319
13.9.4	Substation control enclosure environmental system.....	320
13.9.5	Eliminating the centralized control enclosure.....	321
13.10	References .....	322
<b>14</b>	<b>Using Power System Information .....</b>	<b>323</b>
14.1	Introduction .....	323
14.2	Asset Management .....	323
14.3	SEL Multifunction Relays: A Wealth of Information.....	324
14.4	Upgrading Protection, Control, and Monitoring Equipment.....	325
14.5	Upgrading a Substation Using SEL Multifunction Relays .....	326
14.5.1	Integrated system architecture .....	326
14.5.2	System functionality .....	327
14.5.2.1	Protection .....	327
14.5.2.2	Control .....	327
14.5.2.3	Metering.....	328
14.5.2.4	SCADA functionality .....	328
14.5.2.5	Fault recording.....	328
14.5.2.6	Sequential events recording .....	328
14.5.2.7	Blocking.....	328

14.5.2.8	Tagging.....	328
14.5.2.9	Transformer monitoring .....	328
14.5.2.10	Breaker monitoring.....	328
14.5.2.11	Battery monitoring.....	328
14.5.2.12	Substation control enclosure and weather monitoring.....	328
14.5.2.13	Information display system.....	329
14.5.3	Substation control enclosure.....	329
14.5.4	Additional cost considerations .....	329
14.6	Data Monitoring and Analysis Improve Asset Management .....	330
14.6.1	Data flow .....	330
14.6.2	Transformer monitoring .....	330
14.6.2.1	Thermal monitoring.....	331
14.6.2.2	Loss-of-life monitoring .....	331
14.6.2.3	Through-fault monitoring.....	331
14.6.2.4	Phase current monitoring .....	331
14.6.2.5	Cooling fan monitoring .....	331
14.6.3	Breaker monitoring.....	332
14.6.4	Capacitor bank monitoring .....	333
14.6.5	Battery monitoring.....	333
14.6.6	Synchroscope for autosynchronizer .....	333
14.6.7	Substation control enclosure and weather monitoring .....	333
14.6.8	Applications.....	334
14.7	References.....	334
<b>Index.....</b>		<b>337</b>
<b>Biographies.....</b>		<b>359</b>

# List of Figures

Figure 1.1	(a) The Global Positioning System provides an accurate and globally available reference for time-synchronized measurements (picture courtesy of U.S. Department of Defense). (b) Terrestrial networks using the SEL ICON also provide an accurate time reference over a wide area.....	2
Figure 1.2	Recloser mounted on a distribution pole. Modern recloser controls provide protection, control, and monitoring functions that meet the requirements of today’s distribution systems.....	2
Figure 1.3	Transmission systems have evolved from regional networks to interconnected power grids covering large geographical areas.....	3
Figure 1.4	Modern solutions for transformer protection and monitoring prevent costly failures and extend transformer life.....	4
Figure 1.5	Buses can have complex configurations. Modern relays monitoring the bus and breakers provide fast and secure bus and breaker-failure protection.....	4
Figure 1.6	New generation sources require better generator protection, control, and monitoring. These distributed, intermittent sources also challenge transmission and distribution system protection and control.....	5
Figure 1.7	Wide-area protection, control, and monitoring systems reduce the risk of major blackouts in modern power systems, which operate close to their security limits. ....	5
Figure 1.8	The number of electronic vulnerabilities reported worldwide has increased dramatically. Modern techniques allow us to provide cybersecurity in depth. This figure was created by Schweitzer Engineering Laboratories, Inc., using information from [1]. ....	6
Figure 1.9	Power system reliability is critically important to daily life, so protection systems must perform correctly to preserve system integrity during all types of conditions.....	7
Figure 1.10	Modern technology provides low-cost, complete solutions for power system protection, control, and monitoring. ....	7
Figure 1.11	Modern relays provide a wealth of information for asset management in electric utilities and industrial companies.....	7
Figure 2.1	Synchrophasors associate phasor measurements to an absolute time reference across the power system.....	9
Figure 2.2	SEL satellite-synchronized clocks. ....	10
Figure 2.3	Preferred high-accuracy IRIG-B time distribution methods. (a) Clock with single high-accuracy IRIG-B output. (b) Clock with multiple high-accuracy IRIG-B outputs. ....	11
Figure 2.4	Using a communications processor in a substation IRIG-B signal distribution system. ....	11
Figure 2.5	Time-distribution hierarchy using the IEEE Standard 1588 implemented on Ethernet switches.....	12
Figure 2.6	Synchrophasor representation using the UTC reference. ....	12
Figure 2.7	Voltages at different network locations.....	13
Figure 2.8	Phasor angle measurements at two locations at off-nominal frequency. ....	13
Figure 2.9	Active and reactive power transfer depends on the magnitudes and angles of the system voltages.....	13
Figure 2.10	Architecture of a device that combines time-synchronized measurements with PCM functions.....	15
Figure 2.11	Measured, actual, and error phasors. The circle encompasses all possible phasor measurements for a specified <i>TVE</i> value. ....	15
Figure 2.12	Power system model, synchrophasor data acquisition system, and visualization applications. ....	16
Figure 2.13	Three-source RTDS power system model with four SEL-421 relays acting as PMCUs for synchrophasor measurement and protection.....	16
Figure 2.14	SEL-5078 SYNCHROWAVE Console Software screens showing the angle and frequency difference between Bus 1 and Bus 4 for pre-fault and post-fault conditions. The system oscillations damp out after load shedding. ....	17
Figure 2.15	Synchrophasor data (positive-sequence impedance and voltage magnitude) measured by PMCU 3 for a three-phase fault on Line 3. No synchrophasor data were lost during the fault condition.....	18
Figure 2.16	Angle difference between voltages at Bus 3 and Bus 4 calculated from the synchrophasor data measured by PMCU 3 and PMCU 4. ....	18
Figure 2.17	SYNCHROWAVE Console visualization showing positive-sequence impedance magnitudes calculated by PMCU 3 from protection and synchrophasor data. ....	18
Figure 2.18	Two-source RTDS power system model with two SEL-421 relays acting as PMCUs for synchrophasor measurement.....	19
Figure 2.19	Comparison of Bus 1 to Bus 2 angle difference measured by PMCUs and calculated by RTDS for a 200 ms three-phase fault. ....	19
Figure 2.20	Comparison of Bus 1 to Bus 2 angle difference measured by PMCUs and calculated by RTDS for a 250 ms three-phase fault. ....	19

Figure 2.21	SEL-3306 Synchrophasor Processor and SEL-3373 Station PDC.....	20
Figure 2.22	SEL-3378 Synchrophasor Vector Processor and SEL-3530 Real-Time Automation Controller.....	20
Figure 2.23	SEL-3378 functionality.....	21
Figure 2.24	SEL devices with time-synchronized measurement ability.....	23
Figure 2.25	Combining time-aligned data from different locations in one oscillogram simplifies fault analysis (courtesy of B. D. Eisenbarth, Nebraska Public Power District).....	24
Figure 2.26	Time-aligned event report obtained using the EVE P command.....	24
Figure 2.27	Time-synchronized reports obtained from two SEL-421 relays at different locations.....	24
Figure 2.28	Synchrophasor system using a real-time synchrophasor processor.....	24
Figure 2.29	Using one synchrophasor processor in a local system.....	25
Figure 2.30	Using several synchrophasor processors in a wide-area system.....	25
Figure 2.31	Example of SEL synchrophasor system using different communications channels.....	25
Figure 2.32	SCADA application of synchrophasors.....	26
Figure 2.33	SEL SYNCHROWAVE Console synchrophasor screen.....	27
Figure 3.1	Overcurrent protection is time-delayed to provide coordination.....	30
Figure 3.2	Functional diagram of the SEL-351S Protection System.....	31
Figure 3.3	Microprocessor-based multifunction recloser controls. (a) SEL-351R Recloser Control. (b) SEL-651R Advanced Recloser Control.....	31
Figure 3.4	SEL protection, control, and metering panel for three feeders. Three SEL-351 relays replace nine phase relays, three ground relays, three reclosing relays, and many auxiliary relays.....	32
Figure 3.5	SEL-501 Dual Universal Overcurrent Relay provides two sets of overcurrent, breaker-failure, and motor protection functions.....	32
Figure 3.6	Negative-sequence elements benefit feeder, bus, and backup protection.....	33
Figure 3.7	Negative-sequence overcurrent element.....	33
Figure 3.8	Negative-sequence overcurrent elements easily coordinate with devices that respond to phase currents.....	33
Figure 3.9	Defining an equivalent phase element, you can use the normal coordination procedure for negative- sequence overcurrent elements.....	34
Figure 3.10	Coordination between a negative-sequence overcurrent element and the phase overcurrent element of a downstream recloser.....	34
Figure 3.11	Coordination between a negative-sequence overcurrent element and a downstream 100T fuse (courtesy of BC Hydro).....	34
Figure 3.12	The SEL positive-sequence, voltage-polarized directional element (32P) provides directional discrimination for three-phase faults.....	35
Figure 3.13	Negative-sequence network for a ground fault at the end of the protected line in a two-source system.....	37
Figure 3.14	Operating characteristics of the SEL 32Q and 32V directional elements.....	37
Figure 3.15	Zero-sequence network for a forward ground fault in an ungrounded system.....	38
Figure 3.16	The SEL zero-sequence, voltage-polarized directional element for ungrounded systems (32U) provides sensitive and selective ground fault detection.....	38
Figure 3.17	Single-line diagram and zero-sequence network of a resonant-grounded distribution system.....	39
Figure 3.18	SEL wattmetric directional element (32W) provides sensitive and selective ground fault detection in resonant-grounded systems.....	39
Figure 3.19	Zero-sequence network for a forward ground fault in a resistance-grounded system.....	40
Figure 3.20	Application of a zero-sequence, voltage-polarized directional element (32V) to a high-resistance grounded system.....	41
Figure 3.21	A high-impedance fault detection system that uses the total nonharmonic content of phase currents to detect arcing activity.....	41
Figure 3.22	High load current makes traditional bus phase overcurrent elements ineffective as feeder relay backup protection.....	42
Figure 3.23	Cold-load restoration scheme improves sensitivity by temporarily changing the pickup current of phase and ground overcurrent elements without modifying their time-current curve.....	43
Figure 3.24	Traditional local-area islanding detection uses voltage and frequency variations as indicators of islanding.....	44
Figure 3.25	SEL local-area islanding detection element.....	44
Figure 3.26	Power system model to analyze the performance of islanding detection schemes.....	44
Figure 3.27	SEL islanding detection scheme is faster than traditional schemes.....	44
Figure 3.28	Direct transfer trip over a communications channel provides islanding detection when DG active power generation matches the local-area load.....	45
Figure 3.29	SEL-351 relays protect a wind farm. Multifunction SEL relays provide comprehensive interconnection protection for DG installations.....	46
Figure 3.30	SEL-751A with a point sensor connected to the arc-flash card.....	48
Figure 3.31	Inverse-time characteristic of the SEL-751A arc-flash TOL elements.....	48
Figure 3.32	SEL-751A fault event report containing current and light data.....	49
Figure 3.33	Switchgear application example.....	49

Figure 3.34	Automatic throw-over scheme using SEL-351R Recloser Controls and MIRRORRED BITS communications. ....	50
Figure 3.35	Elementary diagram of a network reconfiguration scheme using SEL-651R Advanced Recloser Controls and MIRRORRED BITS communications. ....	51
Figure 3.36	In a centralized distribution automation system, a DAC coordinates the control logic and communication among the IEDs. ....	52
Figure 3.37	International Drive system single-line diagram. ....	52
Figure 3.38	Overhead AutoRANGER FCIs automatically adjust to varying load conditions. ....	53
Figure 3.39	Test point FCIs are an economical, durable solution. ....	53
Figure 3.40	The RadioRANGER Wireless Fault Indication System communicates FCI status from phase sensors in an underground vault to a handheld remote fault reader. ....	53
Figure 3.41	Remote displays provide indication from the outside of a pad-mounted transformer, switchgear, and other enclosures to facilitate quick, easy fault locating. ....	54
Figure 4.1	The power system of North America includes several large ac transmission systems interconnected through asynchronous (dc) links. ....	58
Figure 4.2	In modern power systems, contingency studies may not include all possible real-life events. ....	58
Figure 4.3	Directional overcurrent protection application in a two-source power system. ....	61
Figure 4.4	Impedance-plane representation of distance element operation. ....	61
Figure 4.5	Distance protection application in a two-source power system. ....	62
Figure 4.6	provides information on the location of the fault with respect to the relay reach point. ....	64
Figure 4.7	Mho element characteristic derivation. ....	64
Figure 4.8	Mho element characteristics. (a) Self-polarized mho element. (b) Polarized mho element responding to a forward fault. (c) Polarized mho element responding to a reverse fault. ....	65
Figure 4.9	Shaping a quadrilateral distance characteristic requires reactance, resistance, and directional elements. ....	66
Figure 4.10	Reactance element characteristic derivation. ....	66
Figure 4.11	The characteristic of a reactance element polarized with $\bar{I}_2$ or $\bar{I}_0$ adapts to the tilt that power flow causes in the apparent fault impedance. ....	67
Figure 4.12	Adaptive resistance element characteristic. ....	68
Figure 4.13	Distance calculation of a phase mho element with long polarizing memory during a frequency excursion. ....	69
Figure 4.14	A mho element with long polarizing memory can misoperate during frequency excursions. (a) Disturbance starts. (b) $\bar{V}_{P\ MEM}$ moves into the operating region. ....	70
Figure 4.15	Adaptive polarizing scheme. ....	70
Figure 4.16	Distance calculation of a phase mho element with adaptive polarizing memory. ....	70
Figure 4.17	Zone 1 mho element using dual-filter scheme. ....	71
Figure 4.18	The SEL-421 Protection, Automation, and Control System provides high-speed line protection, advanced control and monitoring functions, and synchrophasor measurements. ....	71
Figure 4.19	Half- and one-cycle combined logic for the A-phase-to-ground fault loop. ....	72
Figure 4.20	Half-cycle and one-cycle signals for an A-phase-to-ground fault. ....	72
Figure 4.21	Infeed effect causes impedance measurement errors. ....	72
Figure 4.22	For resistive faults, relays at both line ends measure only a portion of the current flowing through the fault resistance. ....	73
Figure 4.23	Fault resistance causes distance element measurement errors. ....	74
Figure 4.24	Complex voltage plane representation of a resistive fault in a nonhomogeneous system. ....	74
Figure 4.25	Zero-sequence network for a ground fault in the system shown in Figure 4.22. ....	75
Figure 4.26	Mutual coupling affects ground distance and directional elements. ....	75
Figure 4.27	Load-encroachment element characteristic. ....	76
Figure 4.28	Power system model. ....	76
Figure 4.29	Measured impedances for an AG fault. ....	77
Figure 4.30	Measured impedances for a BCG fault. ....	77
Figure 4.31	CCVTs with passive FSCs have better transient response than CCVTs with active FSCs. ....	78
Figure 4.32	CCVT blocking logic output for CCVT transient with $SIR = 10$ . ....	78
Figure 4.33	LOP algorithm overview. ....	79
Figure 4.34	Direct underreaching transfer trip logic. ....	79
Figure 4.35	Permissive underreaching transfer trip logic. ....	80
Figure 4.36	Permissive overreaching transfer trip logic. ....	80
Figure 4.37	Directional comparison blocking logic. ....	80
Figure 4.38	Fault-resistance coverage regions of directional comparison schemes in an example two-source system [24]. ....	81
Figure 4.39	Hybrid directional comparison logic. ....	83
Figure 4.40	Current-only pilot schemes compare current information from all the line terminals. ....	84
Figure 4.41	Alpha-plane representation of power system load and fault conditions. ....	85
Figure 4.42	Effect of channel-delay compensation errors. ....	85
Figure 4.43	Alpha-plane differential element characteristic. ....	86

Figure 4.44	The alpha-plane differential element is more sensitive and more tolerant of channel asymmetry than percentage differential elements. ....	86
Figure 4.45	The alpha-plane differential element is more sensitive and more tolerant of CT saturation than percentage differential elements. ....	87
Figure 4.46	Effect of using restraining currents and external fault detection logic in the generalized alpha-plane differential element for CT saturation conditions. ....	88
Figure 4.47	The SEL-311L Line Current Differential System combines line differential and directional comparison protection. ....	90
Figure 4.48	Logic and time diagrams of a half-wave phase comparison protection scheme. ....	91
Figure 4.49	Fault-resistance coverage of SEL-311L negative- and zero-sequence differential elements. ....	92
Figure 4.50	Voltage inversion may affect the directional discrimination of the faulted line and adjacent line relays. ....	94
Figure 4.51	In series-compensated lines, distance elements may overreach because of the impedance oscillation caused by the subharmonic-frequency transient. ....	95
Figure 4.52	The SEL-421 relay series-compensation algorithm blocks the Zone 1 element when the fault is beyond the series capacitor. ....	95
Figure 4.53	The measured voltage, the calculated voltage, and their ratio vary as the fault location moves along the series-compensated line. ....	96
Figure 4.54	Positive-sequence voltage is a reliable polarizing quantity for mho elements used in SPT schemes. ....	97
Figure 4.55	Simultaneous faults on two parallel lines. ....	98
Figure 4.56	Power swings may cause undesirable distance element operation. ....	99
Figure 4.57	SEL relays use a power swing detection characteristic composed of two concentric polygons. ....	99
Figure 4.58	Phasor diagram of a two-source power system. ....	100
Figure 4.59	Negative-sequence network for an unbalanced fault in the system shown in Figure 4.22. ....	104
Figure 5.1	Typical differential element connection diagram. ....	108
Figure 5.2	Percentage differential element single- and dual-slope operating characteristics. ....	109
Figure 5.3	Adaptive differential element characteristic. ....	109
Figure 5.4	DABY or Dy1 transformer connection. ....	110
Figure 5.5	YDAC or Yd1 transformer connection. ....	110
Figure 5.6	Microprocessor-based transformer relays allow connecting CTs in wye. ....	111
Figure 5.7	Microprocessor-based transformer relays perform current scaling, phase-shift compensation, and zero-sequence current removal. ....	111
Figure 5.8	DAB-connection compensation. ....	111
Figure 5.9	Zero-sequence current flows only on the wye side of a delta-wye transformer for external ground faults. ....	112
Figure 5.10	A grounding bank within the differential protection zone requires removing the zero-sequence current. ....	112
Figure 5.11	Exciting current of an overexcited transformer. ....	113
Figure 5.12	Response of a C100, 600/5 CT to a 12,000 A fault current with dc offset. ....	114
Figure 5.13	The SEL-387 Current Differential and Overcurrent Relay provides protection, control, and monitoring functions for transformers and autotransformers. ....	115
Figure 5.14	Differential element blocking based on determining the dc content of the differential current. (a) Inrush current. (b) Internal fault current. ....	116
Figure 5.15	Even-harmonic restrained 87R1 and unrestrained 87U1 differential elements. ....	117
Figure 5.16	DC-ratio blocking logic. ....	117
Figure 5.17	Differential-element blocking logic. ....	117
Figure 5.18	Differential relay common harmonic blocking logic. ....	117
Figure 5.19	Adaptive differential element runs harmonic restraint and blocking in parallel. ....	118
Figure 5.20	Schematic diagram of the SEL-487E Transformer Differential Protection Relay. ....	119
Figure 5.21	Negative-sequence differential element. ....	120
Figure 5.22	Transformer neutral current magnitude is higher than phase current magnitude for ground faults close to the transformer neutral. ....	121
Figure 5.23	REF protection for two-winding transformers using a current-polarized directional element. ....	121
Figure 5.24	REF protection for an autotransformer with two breakers on the high-voltage side. ....	122
Figure 5.25	Typical transformer overcurrent relay protection scheme. ....	124
Figure 5.26	Combined transformer and bus protection. (a) One relay provides a combined protection zone. (b) Two relays provide separate bus and transformer zones. ....	126
Figure 5.27	An SEL-487E relay provides transformer differential protection, fast bus tripping, and protection for up to three radial feeders. ....	126
Figure 5.28	Screen capture of a transformer-monitoring HMI module using microprocessor-based relays to monitor transformer loading and temperatures, and to estimate loss-of-life data. ....	128
Figure 5.29	The transformer thermal model uses the ambient temperature to calculate other temperatures. ....	128
Figure 5.30	Section of the through-fault capability curve for a 100 MVA, Category IV transformer with $Z_T = 0.07$ p.u. ....	131
Figure 5.31	Transformer through-fault monitoring and alarm logic. ....	131

Figure 5.32	Overheating of insulation components and severe through faults reduce transformer stress-withstand capability. ....	132
Figure 6.1	Bus differential overcurrent protection scheme. ....	137
Figure 6.2	Equivalent circuit of the differential overcurrent scheme when the CT of the faulted branch circuit is fully saturated. ....	137
Figure 6.3	SEL-587Z High-Impedance Differential Relay. ....	138
Figure 6.4	Bus high-impedance differential protection scheme. ....	139
Figure 6.5	Cutaway of SEL-587Z High-Impedance Differential Relay. ....	139
Figure 6.6	Summing junction voltage for a 40 kA asymmetrical internal fault in a high-impedance differential scheme with C200, 1200:5 CTs. ....	140
Figure 6.7	Bus percentage differential protection scheme. ....	141
Figure 6.8	Using SEL-487B relays to protect buses with as many as 18 terminals. ....	141
Figure 6.9	The SEL-487B Bus Differential and Breaker-Failure Relay. ....	142
Figure 6.10	Block diagram showing the logic for Bus Protection Zone 1. ....	143
Figure 6.11	Advanced differential element response to an internal fault with CT saturation. ....	144
Figure 6.12	Advanced differential element response to an external fault with severe CT saturation. ....	144
Figure 6.13	Bus partial differential protection scheme. ....	144
Figure 6.14	Zone-interlocked, directional comparison bus protection application. ....	145
Figure 6.15	Zone-interlocked, directional comparison scheme logic. ....	145
Figure 6.16	Fast bus-tripping scheme application. ....	147
Figure 6.17	Fast bus-tripping scheme logic. ....	147
Figure 6.18	Basic breaker-failure protection scheme. ....	149
Figure 6.19	Basic breaker-failure scheme time chart. ....	149
Figure 6.20	The breaker-failure protection scheme with fault detector supervision after the timer provides consistent delay. ....	150
Figure 6.21	Subsidence decaying current flows in the CT secondary circuit after primary fault current interruption. ....	150
Figure 6.22	Logic for detecting an open-phase condition in less than one cycle. ....	150
Figure 6.23	The open-phase detection logic operates in less than one cycle. ....	151
Figure 6.24	The breaker-failure protection scheme with open-phase detector supervision provides fast reset. ....	151
Figure 6.25	Breaker-failure scheme with alternate initiation logic. ....	152
Figure 6.26	Breaker-failure protection logic for multiphase faults. ....	152
Figure 6.27	Breaker-failure protection logic for single-phase-to-ground faults. ....	152
Figure 6.28	Breaker-failure tripping logic in a substation with single-bus, single-breaker configuration. ....	153
Figure 6.29	Breaker-failure tripping logic for a bus involving a transformer. ....	154
Figure 6.30	Breaker-failure tripping logic for a ring-bus configuration. ....	154
Figure 6.31	Bus arrangement with four buses and eight terminals. ....	155
Figure 6.32	Graphical description of a four-bus-zone, eight-terminal system. (a) Connection status when DS1, DS2, and DS3 are open. (b) Bus-zone-to-bus-zone connection status when DS1 is closed and DS2 and DS3 are open. (c) Protection zone formation with bus zones. (d) Protection zone formation with terminals. ....	155
Figure 6.33	Check zone application example. ....	156
Figure 6.34	Bus differential tripping algorithm. ....	156
Figure 6.35	Breaker-failure tripping algorithm. ....	156
Figure 7.1	SEL-300G generator relays provide protection, control, and monitoring functions for generators. ....	160
Figure 7.2	SEL-700G generator relays provide protection, control, and monitoring functions for generators, including wind-driven units, and also intertie protection. ....	160
Figure 7.3	Generator differential protection scheme. ....	160
Figure 7.4	SEL-300G1 relay ac connection for a high-resistance-grounded generator with percentage differential protection. ....	161
Figure 7.5	Split-phase protection using flux-summing CTs. ....	162
Figure 7.6	Split-phase protection using percentage differential elements. ....	162
Figure 7.7	SEL-300G1 relay ac connection for a high-resistance-grounded generator with split-phase protection using flux-summing CTs. ....	162
Figure 7.8	SEL-300G1 relay ac connection for a high-resistance-grounded generator with split-phase protection using percentage differential elements. ....	162
Figure 7.9	Generator high-resistance grounding using a distribution transformer. ....	163
Figure 7.10	Distribution of third-harmonic voltage for various operating conditions. (a) Normal operation. (b) Ground fault at the neutral point. (c) Ground fault at the generator terminals. ....	163
Figure 7.11	A two-element stator ground fault protection scheme provides 100 percent coverage to generator windings. ....	164
Figure 7.12	SEL-300G0 relay ac connection for a resistance-grounded generator with ground differential (87N) and ground overcurrent (50N/51N) elements. ....	165

Figure 7.13	The SEL-2664 Field Ground Module measures the rotor winding insulation resistance and communicates the measured values to the SEL-300G or SEL-700G relay via a fiber-optic channel. ....	166
Figure 7.14	The dc-switching method measures the field resistance to ground. The measured resistance is very high under normal conditions and lower for ground faults. ....	166
Figure 7.15	Voltage measured across the sensing resistor for normal and fault conditions. ....	166
Figure 7.16	Bridge equivalent circuit of the Figure 7.14 circuit. ....	166
Figure 7.17	Using an SEL-2600 series RTD module to convert the outputs from temperature sensors to optical signals avoids long copper wire runs and prevents induced noise and inaccuracies. ....	167
Figure 7.18	Electrical analog circuit of the first-order thermal model. ....	167
Figure 7.19	Time-current characteristics of the SEL-300G and SEL-700G negative-sequence overcurrent elements. ....	169
Figure 7.20	LOF protection using a negative-offset mho element. ....	169
Figure 7.21	Two-zone LOF protection using negative-offset mho elements. ....	170
Figure 7.22	Two-zone LOF protection using a negative-offset mho element and a positive-offset mho element with directional element supervision. ....	170
Figure 7.23	Setting the LOF Zone 2 element according to Figure 7.22 prevents the system from losing steady-state stability, but the generator lacks protection in the highlighted region, located between the capability curve and the LOF element Zone 2 characteristic. ....	171
Figure 7.24	In the P-Q plane representation, we directly use the capability curve and UEL characteristic from the manufacturer. With the setting corresponding to Figure 7.22, the generator lacks protection in the highlighted region. ....	171
Figure 7.25	Setting the LOF element characteristic between the generator capability curve and the UEL characteristic prevents the system from losing steady-state stability and protects the generator. ....	171
Figure 7.26	The P-Q plane representation of Figure 7.25 shows the Zone 2 characteristic correctly set between the generator capability curve and the UEL characteristic. ....	172
Figure 7.27	Turbine blades require cooling. Without the cooling effect of steam passing over the blades of the turbine, overheating and damage can occur. ....	172
Figure 7.28	The SEL-300G relay includes a directional power element with two thresholds for generator motoring protection. ....	172
Figure 7.29	SEL-300G and SEL-700G dual-level, definite-time, volts-per-hertz characteristic. ....	173
Figure 7.30	SEL-300G and SEL-700G composite inverse- and definite-time, volts-per-hertz characteristic. ....	173
Figure 7.31	Example turbine time-frequency characteristic. ....	174
Figure 7.32	Turbine time-frequency characteristic used to design the logic shown in Figure 7.33. ....	175
Figure 7.33	Logic to provide turbine abnormal frequency protection according to Figure 7.32. ....	175
Figure 7.34	Operating characteristic of the SEL-300G and SEL-700G single-blinder out-of-step protection scheme. ....	175
Figure 7.35	Operating characteristic of the SEL-300G and SEL-700G double-blinder out-of-step protection scheme. ....	176
Figure 7.36	SEL-300G and SEL-700G inadvertent energization logic. ....	177
Figure 7.37	SEL-300G and SEL-700G logic for combined breaker-failure and breaker-flashover protection. ....	177
Figure 7.38	Typical phase and ground backup protection for a directly connected generator. ....	177
Figure 7.39	Typical phase and ground backup protection for a generator with a step-up transformer. ....	177
Figure 7.40	SEL-300G and SEL-700G voltage-restrained element pickup current varies with voltage. ....	178
Figure 7.41	SEL-300G mho distance element characteristic. ....	178
Figure 7.42	SEL-300G2 relay ac connection for a high-resistance-grounded generator with synchronism-checking element and without differential protection. ....	179
Figure 7.43	The alarm characteristic is formed by the capability curve and an active-power characteristic. ....	180
Figure 7.44	Recommended protection scheme for large generators. ....	180
Figure 7.45	An alternative protection scheme for large generators. ....	181
Figure 7.46	Recommended protection scheme for small and medium generators. ....	181
Figure 8.1	SSTP includes topology, current, and voltage processors. ....	184
Figure 8.2	Current measurements for KCL check and measurement refinement. ....	184
Figure 8.3	Direct synchrophasor measurements provide better information than SCADA measurements and state estimation. ....	186
Figure 8.4	SVPs detect errors, refine measurements, and send the local estimates to the wide-area state estimator. ....	187
Figure 8.5	SVP peer-to-peer communication provides redundancy. ....	187
Figure 8.6	Scheme to supervise remote voltage measurements. ....	187
Figure 8.7	Transmission line model. ....	188
Figure 8.8	Real-time, MA-based disturbance detection system. ....	189
Figure 8.9	Oscillation-mode based decision and control logic. ....	190
Figure 8.10	MA-based SIPS for a two-area power system with an interarea oscillation problem. ....	190
Figure 8.11	Interarea active power transfer and decision and control logic outputs. ....	191
Figure 8.12	SRP system used for the black-start exercise (courtesy of K. Koellner, SRP). ....	191
Figure 8.13	Frequencies of the islanded SRP system and the WECC system. ....	191
Figure 8.14	SEL-5078 SYNCHROWAVE Console Software capture showing the moment of synchronization. ....	192

Figure 8.15	Simplified representation of the LIPA system. ....	192
Figure 8.16	Adding shunt capacitance to a radial system decreases the system security margin. ....	193
Figure 8.17	LIPA synchrophasor system: phasor measurements at 138 kV East Garden City substation and 23 kV Buell substation; synchrophasor processor at Hicksville headquarters. ....	193
Figure 8.18	An AGSS that uses voltage angle information has lower communications requirements and is more reliable than a traditional AGSS. ....	194
Figure 8.19	Active-power transfer capability mainly depends on voltage angle difference $\delta$ and transmission link reactance when voltage magnitudes are close to nominal values. ....	194
Figure 8.20	When the parallel line in Figure 8.19 opens, voltage angle difference $\delta$ increases. ....	194
Figure 8.21	Grijalva River hydroelectric complex, Chicoasén-Angostura 400 kV transmission link with parallel 115 kV network and future link to Central America (courtesy of E. Martínez, CFE). ....	195
Figure 8.22	Field measurement of the voltage angle difference between Chicoasén and Angostura during switching of A3030 transmission line. ....	195
Figure 8.23	Oscillographic record, from the relay located at Chicoasén, showing line currents, voltage at Chicoasén, and angle difference element operation. ....	195
Figure 8.24	Relays exchange synchrophasors for line backup protection in a two-terminal line application. ....	196
Figure 8.25	FPI logic uses total negative-sequence and zero-sequence fault currents to identify the faulted phase(s). ....	196
Figure 8.26	Power system parameters and operating conditions to analyze $R_F$ coverage of the 87LQ and 67Q elements. ....	197
Figure 8.27	87LQ and 67Q have the same $R_F$ coverage for phase-to-ground faults when set to $0.1I_{NOM}$ sensitivity. Setting the 87LQ element to $0.05I_{NOM}$ improves the element $R_F$ coverage. ....	197
Figure 8.28	Power system parameters and operating conditions to analyze 87LQ and 67Q element performance for a cross-country fault. ....	197
Figure 8.29	FPI, 87LQ, and 67Q operation for a cross-country fault. ....	197
Figure 8.30	Distributed bus differential protection scheme for as many as 64 terminals uses relays at terminal locations and one SVP. ....	198
Figure 8.31	The distributed bus protection scheme uses the topology and current processors to determine the bus protection zones. ....	198
Figure 8.32	Current differential element characteristic, external fault detection logic, and 87R output logic. ....	198
Figure 8.33	Distributed bus differential protection for double bus and transfer bus with multiple terminals. ....	199
Figure 8.34	Synchrophasor-based PSD logic. ....	200
Figure 8.35	OOSD logic uses angle difference information to identify OOS conditions. ....	201
Figure 8.36	Operating characteristic of the OOSD element. ....	201
Figure 8.37	The OOST element uses slip frequency and acceleration information to detect unstable swings. ....	201
Figure 8.38	SIPS suitable for two-area power systems that may use two relays, or two relays and one SVP, to prevent power system instability. ....	201
Figure 8.39	Implementation of the OOST element using the SVP. ....	202
Figure 8.40	System model to analyze the performance of the OOST element in real time. ....	202
Figure 8.41	Angle difference for stable operating conditions. ....	203
Figure 8.42	Angle difference for unstable operating conditions without remedial action. ....	203
Figure 8.43	Angle difference for unstable operating conditions and remedial action to maintain system stability. ....	203
Figure 8.44	Trajectory on the angle difference-slip frequency plane for stable operating conditions. ....	203
Figure 8.45	Trajectory on the angle difference-slip frequency plane for unstable operating conditions. ....	203
Figure 8.46	Trajectories on the angle difference-slip frequency plane before and after the remedial action. ....	204
Figure 8.47	Trajectory on the slip frequency-acceleration plane for stable operating conditions. ....	204
Figure 8.48	Trajectory on the slip frequency-acceleration plane for unstable operating conditions. ....	204
Figure 8.49	Trajectories on the slip frequency-acceleration plane before and after the remedial action. ....	204
Figure 8.50	Implementation of the wide-area islanding detection element using the SVP. ....	205
Figure 8.51	The combination of SEL local-area and wide-area elements provides fast islanding detection even when the DG capacity is close to the islanded area load. ....	205
Figure 8.52	Architecture of the SIPS implemented by IPCo. ....	206
Figure 8.53	Power system with two transmission lines feeding a constant power load. ....	207
Figure 8.54	PV curves of the Figure 8.53 system for normal operating conditions and for operation with one of the transmission lines out of service. ....	207
Figure 8.55	Power system model to study voltage stability. ....	207
Figure 8.56	Voltage magnitudes at buses 8 and 9 of the Figure 8.55 system. When two lines open, both voltages drop below 95 percent (the setting of definite-time undervoltage elements). ....	208
Figure 8.57	Inverse-time undervoltage element characteristic for $A = 28.2$ , $B = 2$ , $p = 2$ , and $V_{PU} = 0.95$ . ....	208
Figure 8.58	Voltage magnitudes at buses 8 and 9 of the Figure 8.55 system. The voltage at Bus 8 recovers immediately after the inverse-time undervoltage element at Bus 9 trips to drop the Bus 11 load. ....	209
Figure 9.1	Power system communications example. ....	213
Figure 9.2	Typical fiber-optic cable construction. ....	215

Figure 9.3	Typical SM optical fiber attenuation as a function of wavelength. ....	215
Figure 9.4	V-pin connector with the optional latching mechanism. ....	215
Figure 9.5	LC connector with the associated SFF transceiver module. ....	216
Figure 9.6	SFP fiber-optic transceiver. ....	216
Figure 9.7	SEL low-cost fiber-optic transceivers. ....	217
Figure 9.8	SEL fiber-optic transceivers mount directly on the back of SEL relays. ....	217
Figure 9.9	SEL-2505 Remote I/O Module. ....	218
Figure 9.10	SEL-2506 Rack-Mount Remote I/O Module. ....	218
Figure 9.11	SEL-2505 application example showing the amount of copper wiring replaced by a direct fiber-optic channel and remote I/O module cabinets. ....	218
Figure 9.12	SEL-2600 Resistance Temperature Detector Module. ....	219
Figure 9.13	SEL-311L Line Current Differential Relay. ....	220
Figure 9.14	SEL products with IEEE C37.94 fiber-optic interface. ....	220
Figure 9.15	IEEE Standard C37.94 fiber-optic interface application examples. ....	221
Figure 9.16	SEL Integrated Communications Optical Network in 19-inch shelf-mount and 8-inch panel-mount packages. ....	222
Figure 9.17	Example of network configuration using the SEL ICON. ....	223
Figure 9.18	SEL-3031 Serial Radio Transceiver. ....	224
Figure 9.19	The SEL-3031 radio provides three serial links between, for example, a recloser control and the substation. ....	225
Figure 9.20	MIRRORED BITS protocol operation. ....	227
Figure 9.21	Example of MIRRORED BITS channel-performance monitoring report. ....	228
Figure 9.22	SEL-2100 Logic Processor. ....	228
Figure 9.23	SEL-4388 MIRRORED BITS Tester. ....	229
Figure 9.24	SEL-4388 MIRRORED BITS Tester application example. ....	229
Figure 9.25	VLAN segregated network. ....	230
Figure 9.26	Layer 2 tagged Ethernet MAC header showing four-byte VLAN tag structure. ....	230
Figure 9.27	SEL supports a wide range of Ethernet products. ....	231
Figure 9.28	Example of Google Earth™-based fault report supplied by a distance relay. ....	234
Figure 10.1	Application example of OT and IT networks in an electric power system. ....	238
Figure 10.2	SEL IED communication connections replace isolated electromechanical devices with IED communication networks. ....	241
Figure 10.3	SEL transceivers connect serial IED copper ports to fiber-optic serial and copper Ethernet LANs. ....	241
Figure 10.4	SEL Ethernet interface test illustrating the ability to withstand ESD. ....	241
Figure 10.5	A star configuration provides a simple and reliable LAN. ....	241
Figure 10.6	Multidrop LAN configuration. ....	242
Figure 10.7	Ring LANs allow for network segment failure and redirection. ....	242
Figure 10.8	Example of SEL serial star LAN with IEDs connected via serial cables using nonroutable protocols with behavior similar to TDM-based communication. ....	242
Figure 10.9	Example of SEL Ethernet star LAN with IEDs connected via Ethernet cables using routable protocols, which is an example of packet-based communication. ....	243
Figure 10.10	A redundant star-connected LAN using redundant ports corrects data flow failures faster than a ring-connected LAN looped among switch-mode IED ports. ....	244
Figure 10.11	High-performance, high-availability, simultaneous redundant data path network design. ....	245
Figure 10.12	SEL-387 through-fault data model showing values, descriptions, context, and time stamp. ....	249
Figure 10.13	SEL information processors. ....	252
Figure 10.14	Information processor creating internal copy of SEL-351 relay database. ....	253
Figure 10.15	Information processor creating internal copies of non-SEL IED databases. ....	253
Figure 10.16	Information processor creating concentrated database with relevant subsets of IED database contents. ....	254
Figure 10.17	Tiered information processors creating concentrated databases with relevant subsets of IED database contents. ....	254
Figure 10.18	Serial network with all information processing functions in one box (an SEL communications processor or rugged computer). ....	257
Figure 10.19	Ethernet network with information processing functions split between two boxes (an SEL communications processor or rugged computer and an Ethernet switch). ....	257
Figure 10.20	SEL ICON bridges OT and IT by supporting both TDM- and packet-based communications. ....	257
Figure 10.21	SEL IEDs separate the processing of protection and automation logic. ....	259
Figure 10.22	SEL IEDs separate user-defined protection and automation logic and variables. ....	259
Figure 10.23	SEL ease-of-use configuration software demonstrates separation of different unique groups of settings. ....	260
Figure 11.1	Sam Spade, an Internet-based network reconnaissance application. ....	266
Figure 11.2	Results of an Nmap TCP port scan with operating system detection activated. ....	267
Figure 11.3	Most SCADA protocols are susceptible to malicious frame injection attacks. ....	268

Figure 11.4	Ethereal TCP/IP network sniffer analyzing captured DNP3 SCADA frames. ....	268
Figure 11.5	Ethereal TCP/IP network sniffer displaying captured login prompt and password.....	269
Figure 11.6	The Back Orifice hijacking suite allows an attacker to completely take over a target PC. ....	270
Figure 11.7	Communications in the electric power industry provide for real-time protection, control, and monitoring, SCADA, and remote engineering access. ....	271
Figure 11.8	Barriers can prevent a successful electronic attack against SCADA or engineering networks. ....	271
Figure 11.9	ESP definitions for the Figure 11.7 network result in a perimeter around the SCADA LAN, the corporate LAN, and the substation or generation station LAN.....	272
Figure 11.10	Example of remote access to a relay via a transparent communications session through an SEL-2032 Communications Processor. ....	273
Figure 11.11	WAN links create electronic attack entry points.....	273
Figure 11.12	Use SEL-3021 Serial Encrypting Transceivers to protect multidrop or point-to-point SCADA networks. ....	274
Figure 11.13	SEL-3021 Serial Encrypting Transceivers protect vulnerable dial-up access links. ....	274
Figure 11.14	Installing the SEL-3022 on the serial port of inaccessible IEDs, such as poletop recloser controls, implements secure, wireless engineering access connections.....	275
Figure 11.15	Inline cryptographic link security modules protect against attacks from outside the ESP, but not against attacks from within. ....	276
Figure 11.16	Sequential events information collected from SEL devices contains status of security-related events.....	278
Figure 12.1	Failure rate patterns over time. Note that with maintenance during the wearout period, the failure rate can be restored to a lower level. ....	282
Figure 12.2	<i>MTBF</i> and unavailability formulae for several system configurations. Each block represents a system component with constant failure and repair rates.....	283
Figure 12.3	Fault tree for a simple overcurrent protection system.....	284
Figure 12.4	Redundant line protection with Relay R1 and Relay R2 trip contacts (Out 1, Out 2) each connected to actuate a corresponding breaker trip coil (TC1, TC2). ....	285
Figure 12.5	Aircraft dual primary systems of one manufacturer: same engines, same radios, same air-data computers, and same flight management systems (courtesy of Cessna).....	286
Figure 12.6	Dual primary protection system with identical relays. ....	286
Figure 12.7	Model of a dual protection system in which a common-mode component failure causes both relays to fail. ....	287
Figure 12.8	The single-board SEL-2431 Voltage Regulator Control has fewer cables, fewer interconnections, and higher reliability than multiboard designs.....	288
Figure 12.9	Real Time Digital Simulator for relay or protection scheme testing. ....	289
Figure 12.10	HALT chamber in SEL environmental test laboratory. ....	289
Figure 12.11	Test at high stress to force and fix failures and widen operating margin.....	289
Figure 12.12	Air electrostatic discharge to SEL product front-panel port. ....	289
Figure 12.13	Environmental stress screening.....	290
Figure 12.14	Ongoing reliability test. ....	290
Figure 12.15	Out-of-Box quality audit.....	290
Figure 12.16	SEL product hospital finds root cause and returns product in 72 hours. ....	291
Figure 12.17	Engineers analyze failure data to improve reliability.....	291
Figure 12.18	Relay self-test report. ....	292
Figure 12.19	Microprocessor-based relay self-testing and monitoring functions replace traditional routine tests. ....	294
Figure 13.1	Record of breaker failure to close caused by dc supply voltage collapse.....	299
Figure 13.2	DC monitoring terminals of SEL-421 relay.....	299
Figure 13.3	Circuit arrangement with PCM and breaker circuits common. ....	300
Figure 13.4	Circuit arrangement with PCM and breaker circuits isolated. ....	301
Figure 13.5	DC circuit routing, radial system. ....	301
Figure 13.6	DC circuit routing, radial system with switchyard routing.....	301
Figure 13.7	Example close logic using contact logic.....	302
Figure 13.8	Example close logic using programmable logic. ....	303
Figure 13.9	Trip circuit monitor logic.....	304
Figure 13.10	Direct tripping example. ....	305
Figure 13.11	SEL-9502 Contact Arc Suppressor. ....	306
Figure 13.12	RIO cabinet located in substation switchyard.....	307
Figure 13.13	Application example of RIO modules and fiber-optic links.....	308
Figure 13.14	Trip output logic with seal in for both internal and external trips. ....	308
Figure 13.15	Tripping multiple devices with one relay.....	309
Figure 13.16	SEL-451 relay with front-panel HMI suitable for local control. ....	309
Figure 13.17	SEL-451 relay with independent controls for trip and close. ....	310
Figure 13.18	Integrated control system design with separate local and remote control systems.....	311
Figure 13.19	SEL-3351 System Computing Platform. ....	311
Figure 13.20	PCM system using serial star networks and dual relaying. ....	312

Figure 13.21	Example of cross-reference I/O table for a dc elementary diagram.....	316
Figure 13.22	Example of cross-reference table for I/O connected through a communications link. ....	316
Figure 13.23	Example logic diagram.....	317
Figure 13.24	Traditional duplex panels. ....	318
Figure 13.25	Modern simplex panel. ....	318
Figure 13.26	Closed-back, swing-front PCM panels featuring SEL microprocessor-based relays and meter.....	319
Figure 13.27	SEL POWERCORE Substation Control Enclosure.....	319
Figure 13.28	SEL POWERCORE using an ISO container for enclosure. ....	320
Figure 13.29	SEL POWERCORE-M. ....	321
Figure 14.1	Elements of an asset management program [3]. ....	324
Figure 14.2	Substation PCM system architecture.....	327
Figure 14.3	All substation data are available to the corporate servers. ....	330
Figure 14.4	Monitoring and controlling cooling fan operation reduce fan failures. ....	332
Figure 14.5	Breaker air compressor monitoring provides early warning of impending compressor failures. ....	332
Figure 14.6	Capacitor bank monitoring provides early detection of control system problems.....	333
Figure 14.7	HMI display of synchroscope using an SEL-451-4 relay for autosynchronizer. ....	333
Figure 14.8	Typical substation control enclosure and weather information HMI screen.....	334

# List of Tables

Table 2.1	SEL-3378 function blocks and functions.....	22
Table 2.2	Size of IEEE Standard C37.118 synchrophasor messages in the SEL-421, SEL-451, SEL-487E, and SEL-487V relays. ....	26
Table 3.1	Interconnection protection and supervision elements provided by SEL relays.....	46
Table 4.1	Summary of transmission line protection challenges. ....	59
Table 4.2	Comparison of transmission line protection principles. ....	60
Table 4.3	Voltage and current input signals to traditional phase and ground distance elements.....	63
Table 4.4	Directional comparison scheme performance summary. ....	81
Table 4.5	Clearing times of directional comparison schemes for faults that plot in each region of Figure 4.38. ....	82
Table 4.6	Fault-resistance coverage of polarized-mho and quadrilateral ground distance elements [31]. ....	92
Table 4.7	Secondary currents and voltages measured by a relay for an open phase in the parallel line and for a ground fault on the protected line [34]. ....	98
Table 5.1	Harmonic content of the current signal shown in Figure 5.11.....	113
Table 5.2	Comparison of independent even-harmonic restraint and common even-harmonic blocking methods. ....	114
Table 5.3	Transformer categories according to the IEEE Standard C57.12.00 [2]. ....	123
Table 8.1	Operating times of 67Q, FPI, and 87LQ elements. ....	198
Table 8.2	Scenarios to analyze the performance of the OOST element. ....	202
Table 8.3	Worst-case operating time budget calculation for the SIPS.....	206
Table 9.1	Response times and event durations for different power system communications applications. ....	212
Table 9.2	Susceptibility to noise bursts per IEC Standard 60834-1. ....	214
Table 9.3	Communications path propagation delay as a function of path length.....	214
Table 9.4	Typical loss values for most popular optical fiber sizes. ....	215
Table 9.5	Ethernet SFP module capabilities (typical values). ....	216
Table 9.6	Characteristics of the SEL-2800 series fiber-optic transceivers. ....	217
Table 9.7	Directional comparison scheme operating times.....	232
Table 10.1	Power system data that IEDs collect and create. ....	246
Table 10.2	Popular network communications methods and their ability to satisfy networked IED tasks.....	256
Table 11.1	Password strength comparison in relays from different vendors.....	276
Table 11.2	Summary of multilevel password-authentication mechanism in SEL devices. ....	277
Table 12.1	Reliability measure definitions. ....	281
Table 12.2	Reliability figures for use in fault trees.....	284
Table 13.1	Need for independent control buttons.....	310
Table 14.1	Actual business case data for comparing substation upgrade program alternatives. ....	326
Table 14.2	Data point count for each substation.....	330
Table 14.3	Power transformer data collected by SEL relays.....	331
Table 14.4	Tracking breaker wear indicators reduces maintenance budgets.....	332
Table 14.5	Real-time capacitor bank performance indicators reduce maintenance costs. ....	333
Table 14.6	Battery and charger monitoring data points.....	333
Table 14.7	Substation control enclosure and weather monitoring data points. ....	334

