ATTACHMENT M

NERC Regulatory Requirements

Standard Number	Requirement Number	Text of Requirement	Location in Document	Monitoring and Measuring Metrics
FAC-003-1	R1.	The Transmission owner shall prepare, and keep current, a formal transmission vegetation management (TVM). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work Specifications. 1. ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.	1.0 TVM Purpose Objectives: 4.08 IVM Approved Procedures: Document Approval Practices / Work Specifications: 4.09 Pruning Standards	This guideline is updated every three years or as needed according to the most recent industry standards.
FAC-003-1	R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.	4.04 System Patrols	Patrol intervals and schedule is identified in Maximo
FAC-003-1	R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.	4.06 Clearance Standards	Clearance distances are identified in section 4.06 (figure 1 and table 1)

FAC-003-1	R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.	4.06 Clearance Standards (figure 1 and table 1(a))	Clearance distances are identified in section 4.06 (figure 1 and table 1)
FAC-003-1	R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.	4.06 Clearance Standards (figure 1 and table 1(c))	Clearance distances are identified in section 4.06 (figure 1 and table 1)
FAC-003-1	R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.	4.06 Clearance Standards (figure 1 and table 1(c))	Clearance distances are identified in section 4.06 (figure 1 and table 1)
FAC-003-1	R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.	4.06 Clearance Standards (figure 1 and table 1(c))	Clearance distances are identified in section 4.06 (figure 1 and table 1(a, b and c))
FAC-003-1	R1.3	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.	4.17 Worker Qualification	Process documented in 4.17 section (for additional information see org chart and licenses)

FAC-003-1	R1.4	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.	3.7 Tree Removal Concerns (mitigation)	Process documented in 3.0 section Patrol cycle adjustments are noted in 4.04
FAC-003-1	R1.5	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.	4.04 System Patrols	Process followed is documented in section 4.04
FAC-003-1	R2.	The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	4.19 Annual Work Plan 3.03 Landowner Notifications	Process followed is documented in section 4.19. Process for notifications is in section 3.03
FAC-003-1	R3.	The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.	4.18 ERCOT Requirements	Monthly report to ERCOT
FAC-003-1	R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.	4.18 ERCOT Requirements	Monthly report to ERCOT
FAC-003-1	R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).	4.18 ERCOT Requirements	Monthly report to ERCOT

FAC-003-1	R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.	4.18 ERCOT Requirements Monthly Report (Attachment L)	Monthly report to ERCOT
FAC-003-1	R3.4.	An outage shall be categorized as one of the following:	4.18 ERCOT Requirements	Monthly report to ERCOT
FAC-003-1	R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;	4.18 ERCOT Requirements	Monthly report to ERCOT
FAC-003-1	R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;	4.18 ERCOT Requirements	Monthly report to ERCOT
FAC-003-1	R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	4.18 ERCOT Requirements	Monthly report to ERCOT

LCRA ENERGY • WATER • COMMUNITY SERVICES	Transmission Services Management System	**Title: ROW Management Plan** **Source: Transmission Services**

Figure 2 – Document Change Form

Sponsor: Peter Larkam Tracking No. (date time) Date: 11-28-07

Purpose: The purpose of this right-of-way (ROW) management plan is to provide guidance to Lower Colorado River Authority (LCRA) staff responsible for managing the transmission ROW owned by the LCRA Transmission Services Corporation (LCRA TSC*) in such a manner to ensure a safe and reliable electric system in a cost-effective and environmentally sensitive manner.

New Document X Existing Document

Stakeholder Review Team (List Names)	**Attachment Documentation Rules:**
1. Ken Barnard 2. Kelly Wells 3. David Turner 4. Mike Almendarez 5. Martyn Turner 6.	New Documents • Are to be in black text and indicated as a new document Additions to Existing Documents: • are to be in color (such as **red** or **blue**) and indicated as an existing document • Deletions are to be ~~strikethrough~~ or Microsoft Track Changes

Management Approval (Supervisors/Managers ~~responsible~~ for managing the tasks as described in the document

1. SERGIO PARRA Date: 12/10/2007
2. 0868 Date: 12/10/2007
3. 1358 Date: 12/10/07
4. 2104 Date: 12/10/07
5. 2141 Date: 12/10/07
6. 1276 Date: 1/15/08

Final Approval (Signature and Date Required)

1505 Date 5/9/08
Manager Approval

Responsible Person
Peter Larkam 1959 Date 5/15/2008

Effective Date of Change: Upon Manager Approval

Revision Date: 02/05/07

LCRA ENERGY • WATER • COMMUNITY SERVICES	Transmission Services Management System	**Title: ROW Management Plan** **Source: Transmission Services**

Communication /Change Plan: Post on intranet. Communicate this procedure directly to the supervisors of each group discussed in this procedure via email, phone and meetings (if needed) and ask that the supervisors communicate this information to their staff.

Stakeholder Review Team

The following signatures represent that an appropriate review has been performed and the Stakeholder Review Team recommends the attached changes to the Management Team for approval.

Stakeholder Review Team Signature/Date.

1. 12/3/07 7. 12-5-07
2. 12/3/07 5. (For Tom Lott) 12/3/07 8.
3. 12-3-07 6. 12/3/07 9.

Lower Colorado River Authority

Standards
for
Inspection and Maintenance of
LCRA Transmission Services Corporation
Equipment and Facilities

September 17, 2008
Revision 4.1

LCRA Transmission Operations
System Reliability & Maintenance Services

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1.0 Purpose

This document establishes standards for the inspection and maintenance of facilities owned by the LCRA Transmission Services Corporation (Corporation). The document will also address future facilities incorporated into the Corporation's Transmission System. Through a service agreement with the Corporation, the LCRA Transmission Services business unit will operate and maintain the Corporation's assets as defined in this document.

This document identifies, for each class of equipment and facilities, the specific planned maintenance and testing to be performed, the standard interval, and in some cases the acceptable test limits. The goal is to ensure that equipment and facilities are kept in good working order. Testing and maintenance may be scheduled on a more frequent basis depending on equipment condition assessment (test and inspection results), equipment performance and criticality of equipment. Actual testing and maintenance may extend beyond stated intervals if 1) equipment is scheduled for replacement the same fiscal year that maintenance is due, 2) unforeseen circumstances i.e. equipment can not be removed from service due to system constraints, major system catastrophe where maintenance/testing resources are needed to repair system.

These standards are based on applicable standards (such as IEEE, ASTM, IEC NERC/ ERCOT criteria); manufacturer recommended guidelines, accepted industry practices; technical reference documents published by EPRI, Doble Engineering, and NERC (specifically the white paper – *Protection System Maintenance- A Technical Reference* dated September 13, 2007); past equipment performance data; knowledge of known failure modes and degradation of equipment components; effectiveness of existing test and maintenance techniques; and good utility practice. Also, the goal of optimizing work efficiencies and the desire to limit the unavailability of equipment due to maintenance were considered. The standards were developed and reviewed by representatives of all stakeholder groups – those who perform the work and those who analyze and review the results. The standards utilize a combination of online (equipment remains in service) and offline (equipment is temporarily removed from service) testing and maintenance techniques.

2.0 Definitions

2.1 Facilities

The term ***facilities*** refer to any equipment, apparatus, or facilities owned by the Corporation.

2.2 Guidelines

The term ***guidelines*** refer to the maintenance guidelines described in Appendices A, B, C, D, and E of this document.

2.3 Standard

The term ***Standard*** shall refer to this document.

2.4 Inspection and Maintenance

The term ***inspection*** shall refer to scheduled and unscheduled patrol and visits to facilities. ***Inspection*** shall also include minor maintenance of air and gas systems, adjustment of equipment settings, and minor maintenance of facilities as specifically described in this Standard.

The term ***maintenance*** shall refer to tests performed on facilities to determine the facilities' condition (diagnostic testing), work performed to restore facilities to good working condition (facilities repair), and work performed to maintain facilities in good working condition (preventive maintenance).

2.5 Asset Performance and Reliability

This group is responsible for developing standards for inspection and maintenance of all facilities.

2.6 Area of Responsibility

By accepting this Standard, each maintenance area is responsible for adhering to and complying with the standards for inspection and maintenance of all facilities.

2.7 Bulk Electric System (Transmission Assets)

Line transmission equipment operated a 200kV and above or line transmission equipment operated at 100kV to 200kV as designated by the Regional Reliability Organization to be critical to the reliability of the electric system.

Transformers with low voltage terminals connected at 200kV and above or transformers with low voltage terminals connected at 100kV to 200kV as designated by the Regional Reliability Organization to be critical to the reliability of the electric system.

3.0 Reports and Records

By accepting this Standard, each Area of Responsibility agrees to maintain the original detailed inspection and maintenance records providing problem descriptions, work performed, and test results. Information contained in such records should be clear and concise, and should accurately reflect the facilities' condition and the nature of the work performed. Each Area of Responsibility agrees to retain all original records in a responsible manner and make all records available and readily accessible. Copies of all inspection and maintenance records will be maintained at the Dalchau Service Center in Austin, Texas.

4.0 Changes and Additions to Standard

This Standard may be changed to modify and/or clarify existing terms, to reflect new methodologies and changing industry practices, and to comply with changing regulatory requirements. Any recommended changes must be reviewed by the System Reliability Team prior to submitting a Document Change request form.

Document Revision Process

The Department Manager or designee will have responsibility and authority to create documents associated with his or her area of responsibility, make changes to them, and keep them up-to-date.

A Document Change Form is used to initiate changes to existing documentation, create new documentation, and remove obsolete documents from use. This form is reviewed by appropriate personnel and then submitted for Management Team approval.

5.0 Substation Facilities

5.1 Inspection

All facilities will be inspected at intervals not to exceed one month in duration. Such inspections shall include visual checks of all facilities. Inspection includes activities associated with routine facilities inspection, emergency and unscheduled facilities inspection, minor maintenance of air and gas systems, adjustment of equipment settings, and inspection of the station battery.

5.2 Repairs

Based upon the results of facilities inspections, any necessary non-emergency repairs to restore facilities to good working condition will be scheduled. Repairs should be scheduled and performed such that normal operation of the facilities is not unduly interrupted.

5.3 Preventive Maintenance

Maintenance will be scheduled to the facilities at intervals specified in Appendix B. However, the maintenance intervals proposed in Appendix B are general guidelines. These guidelines do not address critical facilities, problem facilities, and/or facilities that require special servicing. Facilities requiring maintenance

services that are incompatible with the guidelines proposed in Appendix B shall be identified and appropriate facility maintenance practices shall then be utilized.

5.4 Acceptance Testing

Acceptance tests on new and refurbished facilities shall be performed prior to energization of such facilities. Acceptance tests provide baseline data and ensure that facilities are in good working condition. Appendix A lists facilities for which acceptance tests are required.

5.5 Inspection and Maintenance Procedures

Practices consistent with the substation facilities inspection and maintenance procedures described in Appendix B shall be followed.

5.6 Vegetation Management - Substation

Substation switchyards will be sprayed in the spring season with a follow up spot treatment in the fall season for the control of vegetation growth.
Spring treatments will consist of spraying herbicide to the entire yard, (primarily targeting the graveled areas) while application in the fall will consist of spot treatments on an as needed basis.

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6.0 Transmission Line Facilities

6.1 Inspection

6.1.1 Line Patrol

All Transmission line facilities will be inspected, by either foot patrol and/or fly-over, at periodic intervals as described in Appendix C, Table C1. Line patrol consists of visual checks of the structures' main assemblies, miscellaneous components and apparatus, conductors, shield wires, guy cables, right-of-way (ROW), clearances, and general appearance of line.

6.1.2 Ten Year Inspection

All facilities' lines will be thoroughly inspected every 10 years. Line inspection consists of physical checks of the structures' main assemblies, miscellaneous components and apparatus, conductors, shield wires, guy cables, right-of-way (ROW), clearances, and general condition of line. Any minor maintenance such as tightening of bolts, re-stapling of ground wires, or installation of danger signs should be performed at this time. Inspections are coordinated through a line and right-of-way process as described in Appendix E.

Based upon the results of the ten year inspection, comprehensive plans and schedules for repair and maintenance should be developed in a timely manner.

6.2 Inspection and Maintenance Procedures

Appendix D contains procedures for the maintenance and repair of transmission line facilities identified during patrols and ten-year inspections

6.3 Preventive Maintenance- Line and Right-of-Way

Appendix E contains a process for Maintenance to be scheduled to all line facilities at intervals specified in the line and right-of-way process.

6.4 Vegetation Management - Right-of-Ways

All transmission line right-of-ways (ROW) will be included on a 10-year line maintenance process as set forth in Appendix E. Follow up maintenance will be scheduled on a 2 year or 5 year cycle which ever is needed or as necessary depending on vegetation growth noted on a right-of-way assessments or line patrol reports. Refer to the Electrical Transmission Line Right of Way Management Plan for the most current recommendation and procedures.

7.0 Standards Approval

Recommended for Approval: 1372
Bruce Rushing, Superintendent
Asset Performance and Reliability

Recommended for Approval: 3855
Huntis Dittmar, P.E., Engineering Supervisor
Asset Performance and Reliability

Recommended for Approval: 0826
Eugene Patteson, Manager
Substation Operations

Recommended for Approval: * 0764
Ken Barnard, Manager
Line Operations

Recommended for Approval: 1459
Peter Larkam, P.E., Manager
Asset Performance and Reliability

Approved By: 1358
Bill Hatfield, Manager
Transmission Operations

8.0 Summary of Revisions

Revision #	Date	Revisions
1.0	5/1/2001	Initial document
1.1	11/30/2001	Addition to section 6.3, Revise intervals and infrared limits in section 10.0, Revise section 4.7 intervals
2.0	8/2002	Revision of maintenance intervals, Revised to change references from LCRA to LCRA Transmission Services Corporation
2.1	4/2003	Revision to Right-of-Way and Vegetation control intervals
2.2	6/2005	Revision to Right-of-Way and Vegetation control standards
2.3	9/2005	Revision to Protective Relay Function Testing standards
3.0	5/8/2007	Updated title page, Section 4.0 Changes and Additions to Standard, and Section 7.0 Standards Approval; Major revisions to Appendix B Section 7.0 Protective Relay Systems, Appendix C Section 1.0 Patrol Frequency, Appendix D Section 1.0 Line Patrol Procedures, Appendix D Section 2.0 Ten Year Inspection Procedures, Table D1 Transmission Line Patrol Report (Example), Table D4 Climb Inspection Report (Example), Figure D1 Recommended practices for ROW vegetation management on transmission lines, and Figure D7 Right-of-Way Gate Typical drawing
4.0	1/2008	Added section 5.6 Vegetation Management-Substation, Added section 6.3 & 6.4 Preventive Maintenance and Vegetation Management-Right-of-Ways, Revision to Appendix A, Appendix B revised sections 1.0, 2.0, 3.0, 4.0, 5.0, Added section 6.0 Switches, Revised sections 7.0, 8.0, 9.0, 10.0, 11.0, 13.0, 14.0 & 15.0, Added section 16.0 Miscellaneous Equipment, Revision to Appendix C, Replaced Appendix E.
4.1	9/2008	Revised 1.0 Purpose to add basis for Standard, Revised section 8.3 to extend test interval for calibration of digital relays to 120 mo., revised section 9.0 to extend testing interval for batteries to 24 months and removed reference to capacity test, revised section 10.4 table to correct instrument transformer inspection interval to monthly and 345 kV insulation test as needed.

Appendix A: Substation Facilities Requiring Acceptance Testing

Table A1. Substation Facilities Requiring Acceptance Testing

Equipment/Apparatus	Acceptance Test
New Substation Facilities	Substation Diagnostic Survey performed after station energized
Transformers	Insulation/PF tests on windings and bushings (C1 and C2) Single phase excitation, Turns-ratio, DC winding resistance, Leakage reactance tests, SFRA, TCG for nitrogen blanket units, Insulating medium quality tests Check Core ground insulation Complete baseline DGA before energization DGA and Mini-screen within 3 months of energization Calibrate gauges, sudden pressure relays, pressure relief devices, and monitors Check proper operation of cooling equipment Check proper operation of DETC using TTR PD testing (within 3 months of energization)
Load Tap Changers	Measure contact resistance on reversing switch and moving contacts If applicable, hi-pot (over potential) test vacuum bottles Complete baseline DGA before energization DGA and Mini-screen within 3 months of energization Check proper operation of LTC controls If applicable, check proper operation of filtration unit
Regulators	Insulation/PF Tests Insulating medium quality tests Check proper operation of controls
Circuit Breakers	Insulation/PF Tests on interrupters and bushings Insulating medium quality tests Motion analysis Contact resistance of interrupters and connections Calibrate alarms and gauges
Circuit Switchers	Insulating medium (if equipped with gas ports) Insulation/PF tests and Timing tests Contact resistance of interrupter and switch
Air Switches and Motor Operated Switches	Check proper operation If applicable, hi-pot vacuum interrupter
Transducers and Meters	Calibration tests to verify meter/transducer accuracy Ratio and polarity check current and voltage inputs Verify presence, rotation, and direction/polarity of PT and CT inputs Verify correct operation of digital inputs for alarms Verify correct operation of digital outputs for circuit breaker control, etc.
Relay Systems	Calibration tests on all relay operation elements and targets Function test panels and relay systems Place operational settings on relays according to transmission requirements Ratio and polarity check current transformers Verify presence, rotation, and direction/polarity of PT and CT inputs Verify correct operation of SCADA alarms

Equipment/Apparatus	Acceptance Test
	Function test power line carrier for transmit/receive frequencies Verify correct end-to-end operation of carrier scheme on transmission lines
Batteries	Cell Voltage/Cell Impedance/Strap Resistance/Specific Gravity/Temperature Obtain manufacturer's factory capacity test Post bolt torque verification
Bus/Line/Transformer Arrestors	Excitation current in Watts loss at 10kV equivalent values
Oil-filled Instrument Transformers	Insulation/PF tests PD testing (within 3 months of energization)
Coupling Capacitors	Insulation/PF tests Verify nameplate capacitance
Wavetraps/Line Tuners	Verify frequency bandwidth and range of tuning pack

Appendix B: Substation Facilities Inspection and Maintenance Procedures

APPENDIX B INFORMATION

IMPORTANT NOTE

The following describes maintenance activities that are required on facilities equipment. Manufacturer's procedures should always be consulted and strictly followed when performing all maintenance work. For consistency, however, the activities described in this appendix should be followed when equivalent to the manufacturer's recommendations.

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1.0 Transformers

1.1 Description

Preventive maintenance is conducted on transformers to insure their continued operational reliability. This maintenance consists of routine equipment inspections, routine non-intrusive diagnostic testing, off-line diagnostic testing, and major equipment maintenance/overhauls. The intervals and acceptance criteria shown below are general guidelines.

1.2 Inspection

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

1.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

1.4 Auxiliary Equipment Maintenance

Auxiliary Equipment	Work to be Performed	Calibration	Function Test
Winding temperature gauge	Calibrate gauge/check alarms	Yes	Yes
Oil level gauge	Check gauge and alarms		Yes
Oil temperature gauge	Calibrate gauge/check alarms	Yes	Yes
Ground connections	Verify proper connections on tank/arrestors		
Nitrogen Tank/Cylinder	Check gauges and alarms		Yes
Pressure relief devices	Check alarms		
Sudden pressure devices	Function test/check alarms		Yes
Transformer monitors	Calibrate device/check alarms	Yes	
Oil cooling pumps	Verify proper operation Perform vibration and/or bearing wear analysis		Yes
Fans	Verify proper operation		Yes
Control cabinet	Check wiring, heaters, annunciator, counters		Yes
Oil leaks	Clean up/repair any oil leaks		
Paint	Touch up paint as necessary		

1.5 Major Maintenance/Testing/Overhaul

Transformer Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Insulation power factor	< 0.5% @ 20° C	Yes	Yes	IEEE C57.12.90
10kV Excitation, primary ③	2-high, 1-low pattern	Yes	Yes	Doble
Bushing C1 & C2 power factor ①	C1: < 0.5%, C2: < 1.0% or < 2X variation from nameplate or <50% rate of change from previous test	Yes	Yes	IEEE C57.19.00
Bushing hot-collar test ②	±10% from similar bushings	Yes	Yes	Doble
Surge arrestors watts-loss	±10% from similar arrestors	Yes		Doble
Core ground DC resistance Core ground power factor	Pass/fail < 1.0% @ 20° C	Yes		
DC winding resistance ③	±1.0% from other windings	Yes		
Frequency Response Analysis (FRA)	Similar pattern for all windings	Yes		
Leakage reactance	±5% from nameplate	Yes		
Turns ratio ④	±0.5% from nameplate	Yes	Yes	IEEE C57.12.90

① For bushings with capacitance taps. Power factor limits to be used as a general guide, individual bushing types may vary.
② For bushings without capacitance taps
③ Perform test on maximum DETC tap position and from LTC taps 1R to 16L
④ Perform test on all DETC tap positions and on LTC taps 1R to 16L

Oil/Gas Space Tests

Oil Quality Tests	Acceptance Criteria: Initial Acceptance	Acceptance Criteria: Normal Operation	Initial Test	Routine Maintenance	Reference
Power factor	< 0.1% @ 20° C <1% @ 100° C	< 0.5% @ 20° C <5% @ 100° C	Yes Yes	Yes Yes	ASTM D924
Dielectric strength	>30kV ① >30kV ②	>26kV ① > 26kV ②	Yes	Yes	ASTM D1816 ASTM D877
Interfacial tension	Minimum of 30 @ 20° C	>24 @ 20° C for 69kV >26 @ 20° C for 138kV >30 @ 20° C for 345kV	Yes	Yes	ASTM D971
Acidity	< 0.03	< 0.2	Yes	Yes	ASTM D974
Moisture	< 35 ppm for 69kV < 25 ppm for 138kV <20 ppm for 345kV	< 35 ppm for 69kV < 25 ppm for 138kV <20 ppm for 345kV	Yes	Yes	ASTM D1533
Corrosive Sulfur	None present	None present	Yes		ASTM D1275B
Passivator	Unit dependent	> 20 PPM	No	Yes	
Furan			No	Yes	
H2 Equivalent	<10 PPM	< 100 PPM change from previous test	Yes	Yes	
Total Combustible gas (TCG) ①	< 0.05%	< 0.5%	Yes	Yes	
Dissolved gas analysis (DGA)	Normal limits	Normal limits	Yes	Yes	IEC605.99

① Sealed/Nitrogen blanketed units: use ASTM D1816 with 40 mil gap

② Desiccant/Free breathers: use ASTM D877

Major Maintenance/Overhaul

Maintenance Item	Acceptance Criteria: Initial/Normal Operation
Process/filter oil ①	Meet oil quality standards in Section 1.5
Hot oil/vacuum process windings ②	Meet insulation power factor standards in Section 1.5

① Based on oil test results, filtering and processing of the oil may be required. Processed oil or any new oil must meet the minimum oil quality standards above.

② Based on diagnostic test results, hot oil or vacuum processing of the transformer may be required. Processed oil or any new oil must meet the minimum oil quality standards above.

1.6 Maintenance Activity Guidelines

(Intervals in months)

Transformer Function	Transformer Class	Inspection (Ref 13.0)	H_2 Equ.	DGA + Mini ①	Furan	Diagnostic Tests (Insulation/PF Tests + Aux. Equip) ②	Major Maintenance Overhaul ④
Auto Transformers	EHV (345 kV)	2-Weeks	6	12 ③ ⑤	60	60	As needed
Auto Transformers	HV (138 kV)	1	12	24 ③ ⑤	60	60	As needed
Power Transformers	138 kV	1	12	24 ③ ⑤	72	72	As needed
	69 kV	1	12	24 ③ ⑤	72	72	As needed

① Consists of Dissolved Gas-in-oil Analysis (DGA) and oil mini-screen which includes moisture-in-oil tests (D-1533), IFT (D-971), and acid number (D-974).

② Auxiliary equipment includes gages, indicators, alarms, sensors, pumps, fans, transformer arrestors, power fuses, etc.

③ More frequent testing may be justified based on the results of previous tests.

④ Major maintenance conducted based on results of diagnostic testing.

⑤ For transformers equipped with pumps, perform vibration analysis and/or bearing wear analysis in conjunction with mini-screen tests. H_2 Equ. H_2 and CO (Combustible Gas)

2.0 Load Tap Changers (LTCs)

2.1 Description

Preventive maintenance is conducted on load tap changers to insure their continued operational reliability. This maintenance consists of routine equipment inspections, routine non-intrusive diagnostic testing, off-line diagnostic testing, and major equipment maintenance/overhauls. The intervals and acceptance criteria shown below are general guidelines.

2.2 Inspection

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

2.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

2.4 Auxiliary Equipment Maintenance

Controls and Auxiliary Equipment

Auxiliary Equipment	Work to be Performed	Calibration	Function Test
LTC controls	Verify bandwidth/LDC settings; Perform manual/auto operation of LTC;		Yes
Oil level gauge	Check gauge and alarms		Yes
Pressure relief devices	Verify alarms		
Sudden pressure devices	Calibrate device/check alarms	Yes	Yes
Control cabinet	Check wiring, heaters, annunciator, counters, tags;		Yes
Oil leaks	Clean up/repair any oil leaks		
Desiccant breather	Check/replace desiccant as necessary		
Paint	Touch up paint as necessary		
Oil Filtration	Verify proper operation and pressure differential, replace filter on annual interval		

2.5 Major Maintenance/Testing/Overhaul

Internal Maintenance (Disassembly)

Internal Maintenance	Work to be Performed
Fixed Contacts	Clean components; Remove residue & carbon buildup; Check for wear, damage, & looseness; Check proper alignment, positioning, & wipe; Measure contact resistance
Moving Contacts	Same as Fixed Contacts; Measure contact pressure with load transducer/cell
Diverter arm contacts	Same as Fixed Contacts
Roller contacts	Same as Fixed Contacts
Reversing switch	Same as Fixed Contacts
Collector rings	Same as Fixed Contacts
Head gaskets	Perform leak test on heads. Tighten or replace gaskets as necessary
Drive Mechanism	Lubricate moving parts; Verify timing and synchronicity
Resistors	Check for damage/looseness; Measure resistance values per manufacturer limits
Vacuum bottles	Perform hi-potential test per manufacturer requirements
Cam switches	Verify adjustments, lubricate moving parts
Gears	Lubricate moving parts
Inspection door gaskets	Replace door gaskets as necessary
Oil	Process, filter, or replace oil as necessary

① Lubricate per manufacturer specifications or Doble lubrication guide.

Oil/Gas Space Tests ③

Oil/Gas Space Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Dielectric strength	> 30kV: D1816 w/40 mil gap ① > 30kV: D877 ②	Yes	Yes	ASTM D1816 ASTM D877
Interfacial tension	Minimum of 24 @ 20° C	Yes	Yes	ASTM D971
Acidity	< 0.3	Yes	Yes	ASTM D974
Moisture	< 40 ppm (50% saturation)	Yes	Yes	ASTM D1533
Dissolved gas analysis (DGA)	Normal limits for LTC type	Yes	Yes	Doble

① Sealed/Nitrogen blanketed units

② Free breathers

③ Perform all tests a maximum of three months prior to arcing LTC maintenance and after all LTCs have been re-energized for 3 months.

④ Based on test results prior to maintenance, filtering and processing of the oil may be required. Processed oil or any new oil must meet the minimum oil quality standards above.

2.6 Maintenance Activity Guidelines

(Intervals in months)

LTC Function/Class	LTC Type	Inspection (Ref 13.0)	DGA +mini ①	Maintenance (Internal Insp. + Controls &Aux. Equip.)②
345/138 kV Auto Transformers	Reactive Resistive Vacuum	2-Weeks 2-Weeks 2-Weeks	6 ③ 12 ③ 6 ③	60/30k Op 60/60k Op 60/60k Op
138/69 kV Auto Transformers	Reactive Resistive Vacuum	1 1 1	12 ③ 12 ③ 12 ③	60/30k Op 60/60k Op 60/60k Op
138 and 69 kV Power Transformers	Reactive Resistive Vacuum	1 1 1	12 ③ 12 ③ 12 ③	72/30k Op 72/60k Op 72/60k Op

① Consists of Dissolved Gas-in-oil Analysis (DGA) and oil mini-screen which includes moisture-in-oil tests (D-1533), IFT (D-971), and acid number (D-974).

② Auxiliary equipment includes gauges, indicators, alarms, sensors, etc.

③ More frequent testing may be justified based on the results of previous tests.

Op Number of Operations may vary for specific manufacturer based on previous tests and operational experience.

3.0 Voltage Regulators

3.1 Description

Preventive maintenance is conducted on voltage regulators to insure their continued operational reliability. This maintenance consists of routine equipment inspections, routine non-intrusive diagnostic testing, off-line diagnostic testing, and major equipment maintenance/overhauls. The intervals and acceptance criteria shown below are general guidelines.

3.2 Inspection

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

3.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

3.4 Auxiliary Equipment Maintenance

Controls and Auxiliary Equipment

Auxiliary Equipment	Work to be Performed	Calibration	Function Test
Regulator controls	Verify bandwidth/LDC settings; Perform manual/auto operation of regulator; Verify timing		Yes
Oil level gauge	Check gauge and alarms		Yes
Control cabinet	Check wiring and counters		Yes
Oil leaks	Clean up/repair any oil leaks		
Paint	Touch up paint as necessary		
Ground connections	Verify proper connections on tank/bushing		
Bushings	Verify connections and bypass-arrestors		

3.5 Major Maintenance/Testing/Overhaul

Internal Maintenance (Disassembly)

Internal Maintenance	Work to be Performed
Fixed Contacts	Clean components; Remove residue & carbon buildup; Check for wear, damage, & looseness; Check proper alignment, positioning, & wipe; Measure contact resistance
Moving Contacts	Same as Fixed Contacts; Measure contact pressure with load transducer/cell
Diverter arm contacts	Same as Fixed Contacts
Roller contacts	Same as Fixed Contacts
Reversing switch	Same as Fixed Contacts
Collector rings	Same as Fixed Contacts
Drive Mechanism	Lubricate moving parts
Resistors	Check for damage/looseness; Measure resistance values per manufacturer limits
Vacuum bottles	Perform hi-potential test per manufacturer requirements
Cam switches	Verify adjustments, lubricate moving parts
Gears	Lubricate moving parts
Inspection door gaskets	Replace door gaskets as necessary
Oil	Process/filter oil
Line connections	Tighten all high voltage line/load connections

① Lubricate per manufacturer specifications or Doble lubrication guide.

Insulation/Oil/Gas Space Tests

Insulation/Oil/Gas Space Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Dielectric strength	> 30kV: D877 ①	Yes	Yes	ASTM D877
Interfacial tension	Minimum of 24 @ 20° C	Yes	Yes	ASTM D971
Acidity	< 0.3	Yes	Yes	ASTM D974
Moisture	< 40 ppm (50% saturation)	Yes	Yes	ASTM D1533
Insulation power factor ②	< 2.0%	Yes	Yes	IEEE C57.12.90

① Free breathers

② Perform overall power factor test to ground

Perform all tests a maximum of one month prior to regulator maintenance and after regulator has been re-energized for 3 months. Based on test results prior to maintenance, filtering and processing of the oil may be required. Processed oil or any new oil must meet the minimum oil quality standards above.

3.6 Maintenance Activity Guidelines

(Intervals in months)

Regulator Type	Inspection (Ref 13.0)	Oil Tests ①	Diagnostics (PF Test)	Maintenance (Internal Insp. + Controls + Aux Equip.) ②
Reactive	1	As needed	72/30k Op	72/30k Op
Resistive	1	As needed	72/60k Op	72/60k Op
Vacuum	1	As needed	72/60k Op	72/60k Op

① Consists of Dissolved gas-in-oil analysis (DGA), oil mini-screen which includes moisture-in-oil tests (D-1533), IFT (D-971), and acid number (D-974).

② Auxiliary equipment includes gauges, indicators, alarms, sensors, etc.

Op Number of Operations

4.0 Circuit Breakers

4.1 Description

Preventive maintenance is conducted on oil, SF6, and vacuum circuit breakers to insure their continued operational reliability. This maintenance consists of routine equipment inspections, routine non-intrusive diagnostic testing, off-line diagnostic testing, and major equipment maintenance/overhauls on the interrupter, auxiliary equipment, and operating mechanisms. The intervals and acceptance criteria shown below are general guidelines.

4.2 Inspection

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

4.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

4.4 Auxiliary Equipment Maintenance

Operating Mechanism	Work to be Performed	Calibration	Function Test
Air Compressors	1. Calibrate high/low pressure alarms; 2. Replace compressor oil; 3. Drain condensate receiver; 4. Check dashpot oil level; 5. Perform air system leak check; 6. Replace air filter as necessary; 7. Check air system pressure drop and pump up times; 8. Make mechanism measurements and adjustments on all latches/rollers; 9. Clean/lubricate moving parts ①	Yes	Yes
Hydraulic system	1. Calibrate high/low pressure alarms; 2. Check hydraulic fluid level; 3. Check accumulator precharge; 4. Replace ram seals as necessary; 5. Check pressure drop and pump up times; 6. Make mechanism measurements and adjustments on all latches/rollers; 7. Clean/lubricate moving parts ①	Yes	Yes
Gauges	Check all gauges for damage		
SF6 pressure gauge	Verify high/low pressure alarms	Yes	Yes
Auxiliary switches	Check control wiring and linkages		Yes
Control cabinet	1. Check control wiring, heaters, counters, equipment tags; 2. Perform manual trip/close function check;		Yes

① Lubricate per manufacturer specifications or Doble lubrication guide.

4.5 Major Maintenance/Testing/Overhaul

A. Oil Circuit Breakers Internal Maintenance (Disassembly) (All Voltage Classes excluding Distribution)

Internal Maintenance	Work to be Performed
Fixed Contacts	Clean components and remove residue & carbon buildup; Check for wear, damage, & looseness; Check proper alignment, positioning, & wipe
Moving Contacts	Same as Fixed Contacts
Lift rods/cross-arms	Clean components and remove residue & carbon buildup; Check for wear, damage, & looseness; Check proper alignment and positioning
Tank liner	Inspect for damage
Shock absorbers	Inspect for damage
Bushing CTs	Inspect for damage/loose wiring
Oil level gauge	Check gauge
Oil leaks	Clean up/repair any oil leaks
Paint	Touch up paint as necessary
Bushings	Inspect for damage and clean bushings
Inspection door gaskets	Replace door gaskets as necessary
Oil	Process/filter oil
Ground connections	Verify proper connections on tank
Line connections	Tighten all high voltage line/load connections

Oil Circuit Breaker Electrical Tests (All Voltage Classes excluding Distribution)

Oil Circuit Breaker Electrical Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance
Insulation power factor, Breaker Open ③	< 1.0% @ 20° C	Yes	Yes
Insulation power factor, Breaker Closed ③	< 1.5% @ 20° C	Yes	Yes
Tank Loss Index	Between –0.1 and +0.05	Yes	Yes
Bushing C1 and C2 power factor ①	C1: < 0.5%, C2: < 1.0% or < 2X variation from nameplate or <50% rate of change from previous test	Yes	Yes
Bushing hot-collar test ②	±10% from similar bushings	Yes	Yes
Contact resistance ④	500 micro-ohms or Mfg limit	Yes	Yes

① For bushings with capacitance taps. Power factor limits to be used as a general guide, individual bushing types may vary.
② For bushings without capacitance taps
③ Perform power factor from top of each bushing to ground. Perform test with breaker isolated from bus, if possible.
④ Contact resistance limits to be used as a general guide, individual breaker types may vary.

Oil Quality Tests

Oil Quality Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Power factor	< 0.5% @ 20° C	Yes	Yes	ASTM D924
Dielectric strength	> 25kV: D877	Yes	Yes	ASTM D877
Interfacial tension	Minimum of 24 @ 20° C	Yes	Yes	ASTM D971
Breaker oil analysis (BOA)	Normal limits	Yes	Yes	

① Based on test results prior to maintenance, filtering and processing of the oil may be required. Processed oil or any new oil must meet the minimum oil quality standards above.

B. SF6 Dead-Tank Circuit Breakers Internal Maintenance (Disassembly) (All Voltage Classes)

Internal Maintenance	Work to be Performed
Fixed Contacts	Clean components and remove SF6 arc by-product residue; Check for wear, damage, & looseness; Check proper alignment, positioning, & wipe
Moving Contacts	Same as Fixed Contacts
Lift rods/crossarms	Clean components and remove SF6 arc by-product residue; Check for wear, damage, & looseness; Check proper alignment and positioning
Bushing CTs	Inspect for damage/loose wiring
Paint	Touch up paint as necessary
Desiccant	Replace desiccant as necessary
Inspection door gaskets	Replace door gaskets as necessary
Leaks	Perform leak test
Bushings	Inspect for damage and clean bushings
SF6 gas	Test SF6 purity (%SF6) and dew point/moisture Process SF6 to manufacturer purity/dew point/decomposition limits as required
Ground connections	Verify proper connections on tank
Line connections	Tighten all high voltage line/load connections

SF6 Dead-Tank Circuit Breaker Electrical Tests (All Voltage Classes)

SF6 Dead-Tank Electrical Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance
Insulation watts loss @ 10kV, Breaker Open ①	< .1 Watt	Yes	Yes
Insulation watts loss @ 10kV, Breaker Closed ①	< .3 Watts	Yes	Yes
Insulation watts loss @ 10kV, bushing-bushing ②	< .01 Watt	Yes	Yes
N/A <remove>	<remove>	N/A	N/A
Contact resistance	500 micro-ohms or Mfg. limit whichever is lower	Yes	Yes
Grading capacitors	±10% of capacitor value or Mfg. limit	Yes	Yes
Pre-insertion resistors	±10% of resistor value or Mfg. limit	Yes	Yes

① Apply test voltage to top of each bushing and measure loss to ground. Perform test with breaker isolated from bus, if possible.

② Perform watts loss from bushing to bushing within a phase, done with the breaker open and with the test set in UST mode. Perform test with breaker isolated from bus, if possible.

SF6 Quality Tests

SF6 Quality Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Dew point (moisture)	200 ppm / 200 ppm	Yes	Yes	CIGRE B3.02.01
Arc By-products (SO_2)	12 ppm / 500 ppm *1	Yes	Yes	CIGRE B3.02.01
Purity (%SF6)	97% / 97%	Yes	Yes	CIGRE B3.02.01

*1. 500 ppm limit set at maximum measurable value for field equipment

C. SF6 Live-Tank Circuit Breakers Internal Maintenance (Disassembly) (All Voltage Classes)

Internal Maintenance	Work to be Performed
Fixed Contacts	Clean components and remove SF6 arc by-product residue; Check for wear, damage, & looseness; Check proper alignment, positioning, & wipe
Moving Contacts	Same as Fixed Contacts
Lift rods/crossarms	Clean components and remove SF6 arc by-product residue; Check for wear, damage, & looseness; Check proper alignment and positioning
Bushing CTs	Inspect for damage/loose wiring
Paint	Touch up paint as necessary
Desiccant	Replace desiccant as necessary
Inspection door gaskets	Replace door gaskets/O-rings as necessary
Leaks	Perform leak test
Bushings	Inspect for damage and clean bushings
SF6 gas	Test SF6 purity (%SF6) and dew point/moisture Process SF6 to manufacturer purity/dew point/decomposition limits as required
Ground connections	Verify proper connections on tank
Line connections	Tighten all high voltage line/load connections

SF6 Live-Tank Circuit Breaker Electrical Tests (All Voltage Classes)

SF6 Live-Tank Electrical Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance
Insulation power factor, Breaker Open ①	< 0.5% @ 20° C	Yes	Yes
Insulation power factor, Support column ②	< 0.5% @ 20° C	Yes	Yes
Contact resistance	500 micro-ohms or Mfg. limit whichever is lower	Yes	Yes
Grading capacitors	±10% of capacitor value or Mfg. limit	Yes	Yes
Pre-insertion resistors	±10% of resistor value or Mfg. limit	Yes	Yes

① Perform power factor from bushing to bushing of each separate pole with breaker open. Perform test with breaker isolated from bus, if possible.

② Perform power factor from top of lower support column to ground for each pole. Perform test with breaker isolated from bus, if possible.

SF6 Quality Tests

SF6 Quality Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Dew point (moisture)	200 ppm / 200 ppm	Yes	Yes	CIGRE B3.02.01
Arc By-products (SO_2)	12 ppm / 500 ppm *1	Yes	Yes	CIGRE B3.02.01
Purity (%SF6)	97% / 97%	Yes	Yes	CIGRE B3.02.01

*1. 500 ppm limit set at maximum measurable value for field equipment

D. Vacuum Circuit Breakers Internal Maintenance (Disassembly)

Internal Maintenance	Work to be Performed
Lift rods/crossarms	Clean components; Check for wear, damage, & looseness; Check proper alignment
Bushing CTs	Inspect for damage/loose wiring
Paint	Touch up paint as necessary
Inspection door gaskets	Replace door gaskets/O-rings as necessary
Leaks	Perform leak test
Ground connections	Verify proper connections on tank
Bushings	Inspect for damage and clean bushings
Oil ①	Filter oil
Line connections	Tighten all high voltage line/load connections

① Oil immersed vacuum bottles only.

Vacuum Circuit Breaker Electrical Tests

Vacuum Breaker Electrical Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance
Insulation power factor, Breaker Open ①	< 0.5% @ 20° C	Yes	Yes
Insulation power factor, Breaker Closed ①	< 1.0% @ 20° C	Yes	Yes
Insulation power factor, bushing to bushing ②	< 0.5% @ 20° C	Yes	Yes
Vacuum bottle hi-potential ③	Pass/Fail	Yes	Yes
Contact resistance	200 micro-ohms or Mfg. limit whichever is lower	Yes	Yes

① Perform power factor from top of each bushing to ground
② Perform power factor from bushing to bushing with breaker open
③ Perform during internal maintenance for oil immersed vacuum bottles. Perform during operator maintenance for non-oil immersed vacuum bottles.

4.6 Motion Analysis Testing (All Voltage Classes excluding Distribution)

Motion Analysis Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance
Opening test, all phases ①	Manufacturer limit	Yes	Yes
Opening velocity, all phases ②	Manufacturer limit	Yes	Yes
Closing test, all phases ③	Manufacturer limit	Yes	Yes
Closing velocity, all phases ④	Manufacturer limit	Yes	Yes
Trip-free test ⑤	Manufacturer limit	Yes	Yes
Reclosing Test ⑥	Manufacturer limit	Yes	Yes

① Contact opening time measured from time of energization of trip coil until breaker interrupting contacts part. Test dual trip coils individual.
② Average opening velocity of interrupting contacts in the arcing zone.
③ Contact closing time measured from time of energization of close coil until breaker contacts make.
④ Average closing velocity of interrupting contacts in the arcing zone.
⑤ With breaker open in a trip-free condition, measured from time of energization of the close coil until the interrupting contacts part during the subsequent tripping condition.
⑥ With breaker closed and reclosing enabled, measured from time of energization of the trip coil until the contacts make during the subsequent closing condition.

4.7 Circuit Breaker Maintenance Activity Guidelines - (Intervals in months)

Breaker Type	Inspection (Ref 13.0)	Trip/Close (including operation of switches)	Operator Profile	Pre-charge for Hydraulic Operators	Operator Maintenance Plus Controls/Aux Equipment	Diagnostics: Insulation Medium Tests	Diagnostics: Motion Analysis	Diagnostics: Insulation PF & Contact Resistance	Maintenance (Breaker and Operator Disassembly)
Work Type	**Inspection**	**Maint/Diag**	**Diag**	**Maint**	**Maint**	**Diag**	**Diag**	**Diag**	**Maint**
❑ 69 & 138 kV Class									
■ Ganged Pole									
- Oil	1	12	30	12	30 ③	30	60	60 ①	As required ⑥
- SF6 Puffer	1	12	30	12	30 ③	30 ②	60	60	As required ⑦
■ Independent Pole									
- SF6 Puffer	1	12	30	12	30 ③	30 ②	60	60	As required ⑦
❑ 345 kV Class									
■ SF6 Puffer	2-weeks	12	30	12	30 ③	30 ②	60	60	As required ⑦
■ 2-Pressure SF6	2-weeks	12	30	N/A	30 ③	30 ②	60	60	As required ⑦
❑ Low Voltage (Dist.)									
■ Oil	1	12	N/A	N/A	36 ④	N/A	N/A	N/A	72/60F
■ SF6 Puffer	1	12	N/A	N/A	36 ④	N/A	N/A	N/A	72/80F
■ Vacuum	1	12	N/A	N/A	36 ④⑤	N/A	N/A	N/A	100F ⑧

F Faults

① Insulation medium tests for OCBs include oil dielectric (D-877), power factor (D-924), and breaker gas-in-oil analysis (BOA) based on fault history.

② Insulation medium tests for SF6 breakers include moisture, SF6 purity, and arc by-products/SF6 decomposition, if necessary, based on fault history.

③ Ultimately, performed as required based upon visual inspection, maintenance history, and operator profile.

④ Relays/controls shall be tested and interrupter contact resistance shall be measured during operator maintenance.

⑤ Vacuum interrupters that are not immersed in oil shall be subjected to a hipot test during operator maintenance.

⑥ Performed as required based upon visual inspection, diagnostic test results, maintenance history, or other pertinent factors. Post-disassembly diagnostic tests include insulation/PF, contact resistance, motion analysis, and oil tests. Maintenance includes a complete disassembly of the operating mechanism.

⑦ Disassembly performed as required based upon visual inspection, diagnostic test results, maintenance history, or other pertinent factors. Maintenance includes a complete disassembly of the operating mechanism. No pre-disassembly tests other than insulation medium [see (4) above] are required. Motion analysis, operator profile, and all diagnostic tests (including insulation medium) shall be performed after re-assembly to obtain new baselines.

⑧ Vacuum interrupters that are immersed in oil shall be subjected to a hipot test during disassembly maintenance.

5.0 Circuit Switchers

5.1 Description

Preventive maintenance is conducted on circuit switchers to insure their continued operational reliability. This maintenance consists of routine equipment inspections, routine non-intrusive diagnostic testing, off-line diagnostic testing, and major equipment maintenance/overhauls on the interrupter, auxiliary equipment, and operating mechanisms. The intervals and acceptance criteria shown below are general guidelines.

5.2 Inspection

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

5.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

5.4 Auxiliary Equipment Maintenance

Operating Mechanism and Auxiliary Controls

Operating Mechanism	Work to be Performed	Calibration	Function Test
Gauges	Check all gauges for damage; Calibrate high/low pressure alarms	Yes	Yes
SF6 pressure gauge	Calibrate high/low pressure alarms	Yes	Yes
Auxiliary switches	Check control wiring and linkages		Yes
Control cabinet	1. Check control wiring, heaters, counters, equipment tags; Perform manual trip/close function check; 2. Make mechanism measurements and adjustments on all latches, rollers, and shunt trip devices; 3. Clean/lubricate moving parts; ①		Yes

① Lubricate per manufacturer specifications or Doble lubrication guide.

5.5 Major Maintenance/Testing/Overhaul

Major Maintenance (All Voltage Classes)

Major Maintenance	Work to be Performed
External Switch	1. Check live parts for damage, wear, corrosion, hot spots; 2. Check mechanism linkages for wear and damage;
Paint	Touch up paint as necessary
Leaks	Check and repair any leaks
Bushings	Inspect for damage and clean bushings
SF6 gas	Process SF6 to manufacturer purity/dew point limits, Add gas as necessary (if equipped with fill ports)
Ground connections	Verify proper connections on equipment
Line connections	Tighten all high voltage line/load connections

Circuit Switcher Electrical Tests (All Voltage Classes)

Circuit Switcher Electrical Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance
Insulation watts loss, Circuit Switcher Open ①	< .075 watts	Yes	Yes
Contact resistance, Interrupter	Manufacturer limits	Yes	Yes
Contact resistance, External Switch	500 micro-ohms or Mfg. limit whichever is lower	Yes	Yes
Timing ②	Manufacturer limits	Yes	Yes

① (Depending on circuit switcher type) Perform watts loss from terminal to terminal of each separate pole with circuit switcher open and isolated from bus.

② Contact opening time measured from time of energization of trip coil until circuit switcher interrupting contacts part.

SF6 Quality Tests (if equipped with fill ports)

SF6 Quality Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Dew point (moisture)	200 ppm / 200 ppm	Yes	Yes	CIGRE B3.02.01
Arc By-products (SO_2)	12 ppm / 500 ppm *1	Yes	Yes	CIGRE B3.02.01
Purity (%SF6)	97% / 97%	Yes	Yes	CIGRE B3.02.01

*1. 500 ppm limit set at maximum measurable value for field equipment

5.6 Maintenance Activity Guidelines

(Intervals in months)

Circuit Switchers	Inspection (Ref 13.0)	Trip/Close Check (incl. operation of switches) ①	Interrupter Replacement	Diagnostics (Electrical Tests, Contact Resistance, & Timing)	Maintenance (Maintenance & Operator Insp.)
Power Transformer Applications	1/1 F	12	②	72/250 Op/5 F	72/250 Op/5 F
Capacitor Bank Applications	1/1 F	12	②	36/500 Op/5 F	36/500 Op/5 F

① No trip check performed on circuit switches or motor operated switches that have operated properly within prior 3 months. When by-pass switches are not present, perform trip / close test with the operator de-coupled.

② As required.

F Number of Fault Operations

Op Number of Total Operations

6.0 Switches (motor operated and manual operated)

6.1 Description

Preventive maintenance is conducted on motor operated switches to insure their continued operational reliability. This maintenance consists of routine equipment inspections, routine non-intrusive diagnostic testing, off-line diagnostic testing, and major equipment maintenance/overhauls on the interrupter, auxiliary equipment, and operating mechanisms. The intervals and acceptance criteria shown below are general guidelines.

**Make sure to identify exceptions like use for PTs and some bus tie connections.

6.2 Inspection

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

6.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

6.4 Miscellaneous Equipment Maintenance Activity Guidelines

Air Switches: Maintenance Activity Guidelines.
(Intervals in months)

Voltage Class	Inspection & Switch Exercise (Ref 13.0)	Maintenance + Aux. Equip. ①
69kV	12	As needed
138kV	12	As needed
345kV	12	As needed

① Consists of maintenance on switch live parts, contact resistance measurement, motor operator maintenance. Coordinate with circuit breaker maintenance (5 years) or line maintenance (10 years) as necessary.

7.0 Meters, Transducers, and Recording Equipment

7.1 Description

Preventive maintenance is conducted on meters, transducers, and recording equipment to insure their continued operational reliability. This maintenance consists of routine equipment inspections and routine calibration. The intervals and acceptance criteria shown below are general guidelines.

7.2 Testing and Calibration

Test, adjust, and calibrate per manufacturer's recommendations. Test and calibrate the following:

- ❑ Analog input points
- ❑ Analog output points
- ❑ Digital input points
- ❑ Digital output points
- ❑ Power supply modules
- ❑ Calibrate device to nameplate accuracy specifications

7.3 Maintenance Activity Guidelines

Meters, Transducers, and Recording Equipment
(Intervals in months)

Meters	Operational Check	Calibration
Meters: Revenue & Total		12
Meters: ERCOT settlement		12
Transducers		36
Fault Recorders	12	12
Remote Terminal Units (RTU)		As needed

Revenue/Settlement Metering Instrument Transformers
(Intervals in months)

Equipment	Work To Be Performed	Calibration
Current Transformers	Ratio and burden test Secondary control wiring integrity	12 36
Optical Current Transformers	Ratio test	60
Voltage Transformers	Voltage drop calculation and measurement Secondary control wiring integrity	60 ① 36
Coupling Capacitor Voltage Transformers	Accuracy test	60

① Voltage drop must not exceed 0.3 Volts between voltage transformer and meter.

8.0 Protective Relay Systems

8.1 Description

Preventive maintenance is conducted on protective relay systems to insure their continued operational reliability. This maintenance consists of routine equipment inspections and routine calibration. The intervals and acceptance criteria shown below are general guidelines.

8.2 Testing and Calibration

Test, adjust, and calibrate per manufacturer's recommendations.

Routine Inspections

Equipment	Work to be Performed
Electro-mechanical relays	Inspect for physical damage; Record and reset targets; Verify tags on all equipment.
Solid-state or Digital relays	1. Inspect for physical damage; Record and reset targets. 2. Record stored fault and other stored sequence-of-events data. 3. Verify tags on all equipment.
Wavetraps	Check for physical damage.
Coupling capacitors	Check for physical damage; Verify proper ground connections on equipment.
Power-line carriers	Perform manual carrier test; verify proper current in relay carrier receive circuit where applicable.

Calibration/Function Testing

Equipment	Work to be Performed
Electro-mechanical relays and Solid-state relays	1. Calibrate operating element pickup to manufacturer specifications. 2. Verify operational settings according to latest Transmission System requirements; Verify presence, rotation, and direction/polarity of voltage and current inputs; Verify relay case grounding; Verify all indication lights. 3. Verify proper operation and pickup of target/seal-in units. 4. Calibrate timers (Zone, Breaker Failure, Reclosers, etc) for correct settings. 5. Verify correct operation of all switching devices under relay control. 6. Perform trip check on relay system packages. 7. Tighten control, CT, and PT wiring connections on relays and terminal blocks.
Digital relays	1. Calibrate operating element pickup to manufacturer specifications. 2. Verify operational settings according to latest Transmission System requirements; Verify presence, rotation, and direction/polarity of voltage and current inputs; Verify relay case grounding; Verify all indication lights. 3. Verify proper operation and pickup of trip indications. 4. Calibrate timers (Zone, Breaker Failure, Reclosers, etc) for correct settings. 5. Verify correct operation of all switching devices under relay control. 6. Perform trip check on relay system packages. 7. Verify correct operation of digital relay alarms. 8. Tighten control, CT, and PT wiring connections on relays and terminal blocks.
Wavetraps	1. Perform test to verify frequency bandwidth, impedance, and range of tuning pack.
Line tuners	1. Measure, record, and adjust reflected power, transmit/receive frequencies.
Power-line carriers	1. Measure, record, and adjust reflected power, transmit/receive frequencies, receiver threshold, and power output. 2. Verify correct end-to-end operation of carrier scheme in both directions on transmission lines.
Auxiliary equipment	1. Check AC and DC voltage inputs to all relays, carrier equipment, and auxiliary equipment. 2. Check all PT Fuses. 3. Check all annunciator alarms and panel alarms. 4. Check station service throwover, battery charger functions, and inverter functions. 5. Check hydrogen monitors for correct operation. 6. Check ferroresonance protection circuits for correct operation.

8.3 Protective Relay Maintenance Activity Guidelines

(Intervals in months)

Relay System (Type)	Relay System (Class)	Inspection (Ref 13.0)	Calibration	Function Testing & Trip Check
Lines	❑ 345kV	2-Weeks		
	■ Electro-Mechanical and Solid-State		60	120 ②
	■ Digital		120	120 ②
	❑ 138kV and 69kV	1		
	■ Electro-Mechanical and Solid-State		60	120 ②
	■ Digital		120	120 ②
Bus and Breaker failure	❑ 345 kV	2-Weeks		
	■ Electro-Mechanical and Solid-State		60	120
	■ Digital		120	120
	❑ 138kV and 69kV	1		
	■ Electro-Mechanical and Solid-State		60	120
	■ Digital		120	120
Transformers	❑ 345/138 kV Auto-Transformers	2-Weeks		
	■ Electro-Mechanical and Solid-State		60 ③	60 ③
	■ Digital		120	120
	❑ 138/69 kV Auto-Transformers	1		
	■ Electro-Mechanical and Solid-State		60 ③	60 ③
	■ Digital		120	120
	❑ 138kV and 69kV Power Transformers	1		
	■ Electro-Mechanical and Solid-State		72 ①	72 ①
	■ Digital		72 ①	72 ①
Miscellaneous	Fault Recorders	N/A	12	12
	Capacitor & Reactor Bank	1	60	60
	Power line carriers/ Line Tuners	1	④	120 ②④
	Substation auxiliary equipment	1	60	120
	Underfrequency relays	1	60	120
	Special Protection Schemes (SPS)	1	60	60⑤

① Coordinate with transformer maintenance for stations with only transformer differential protection every 72 months (Ref 1.0).

② Coordinate function testing and trip checks as necessary with circuit breaker maintenance, line maintenance, or operational checks as outages permit. Perform end-to-end trip check on lines as outages permit (Ref 4.0).

③ Coordinate as necessary with transformer maintenance every 60 months (Ref 1.0)

④ Perform in conjunction with transmission line relay testing.

⑤ Perform with generation or line outage that is associated with the SPS.

9.0 Substation Batteries

9.1 Description

Preventive maintenance is conducted on batteries to insure their continued operational reliability. This maintenance consists of routine equipment inspections and diagnostic testing. The intervals and acceptance criteria shown below are general guidelines.

9.2 Inspections

Routine inspection and minor maintenance items are detailed in Section 12.0 of this appendix.

9.3 Diagnostic Testing

Battery Tests	Acceptance Criteria: Initial/Normal Operation	Initial Test	Routine Maintenance	Reference
Cell Voltage	2.15 to 2.25 V per cell (Lead-Acid) 1.38 to 1.47 V per cell (NiCad)	Yes	3 months	
Cell Impedance	±30% of average cell impedance	Yes	24 months	
Strap resistance	±20% of average strap resistance measured post-to-post	Yes	24 months	
Specific Gravity and Temperature	Specific Gravity 1.190-1.275 Temperature 42°F- 92°F	Yes Yes	24 months	
Torque on inter-cell and inter-tier connections	Check torque – per manufacturer specifics	Yes	As Needed	
Battery charger	1. Verify float charge setting: 130-134 V ① 2. Verify equalize charge setting: 139-144 V ① 3. Verify/calibrate hi/low voltage alarms 4. Verify/calibrate DC ground detection alarms	Yes	60 months	
Visual inspections	1. Verify proper electrolyte levels and add distilled water as necessary, if water is added equalize the battery bank for 12 hours 2. Check for damaged or cracked cells or leakage of electrolyte 3. Check for evidence of corrosion at terminals, connectors, and posts 4. Clean cell tops and apply corrosion preventive compound to straps, connections, and posts as needed 5. Verify proper grounding of battery rack; 6. Check overall battery bank voltage and temperature 7. Check for DC ground	Yes	1 month	
Auxiliary equipment	1. Check eyewash		1 month	

① Settings for 60-cell lead acid and 92-cell NiCad battery banks. Decrease float/equalize voltages by 2 V/cell for lead-acid banks if cells are removed or jumpered out. Decrease float/equalize voltage by 1.4 V/cell for NiCad banks.

9.4 Battery Maintenance Activity Guidelines - (Intervals in months)

Batteries / Chargers	Inspection (Ref 13.0)	Cell Voltage ①	Cell Impedance, Strap Resistance	Aux Equipment
Battery Chargers	1	N/A	N/A	60 ②
Batteries	1	3	24	N/A

① Measure voltage of all cells under float charge. Note cell voltages outside acceptance criteria range. Turn off battery charger, wait 10 minutes; measure bank voltage & record DC amp load. Report significant changes in bank voltage (>20%).
② Test/calibrate all battery charger alarms.

10.0 Instrument Transformers and Surge Arresters

10.1 Description

Preventive maintenance is conducted on instrument transformers and surge arresters to insure their continued operational reliability. This maintenance consists of routine equipment inspections and diagnostic testing. The intervals and acceptance criteria shown below are general guidelines.

10.2 Inspections

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

10.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

10.4 Maintenance Activity Guidelines

Instrument Transformers and Surge Arrestors: Maintenance Activity Guidelines.
(Intervals in months)

Voltage Class	Inspection (Ref 13.0)	Diagnostics IR and PD	Accuracy Testing ②	Diagnostics Insulation PF Testing	Acceptance Criteria: Normal Operation
69kV Instrument Transformers	1	12	60	As needed	Insulation Power factor < 0.5%
138kV Instrument Transformers	1	12	60	As needed	Insulation Power factor < 0.5%
345kV Instrument Transformers	1	6	60	As needed	Insulation Power factor < 0.5%
Surge Arrestors	1	12 ①	N/A	N/A	Watts-loss ±20% from similar units

① IR Only
② For Coupling Capacitor Voltage Transformers (CCVTs) and Optical CTs at generating stations or settlement meter points, perform accuracy, ratio, and burden test every 5 years in accordance with ERCOT guidelines. Coordinate with circuit breaker maintenance (5 year) and/or line maintenance (10 years) as necessary.

11.0 Substation Diagnostics

11.1 Description

Non-Intrusive diagnostic testing is conducted on substation equipment to provide information as to the operating condition of the equipment. The intervals and acceptance criteria shown below are general guidelines.

11.2 Inspections

Diagnostic Tests	Work to be Performed	Acceptance Criteria: Normal Operation
Thermography	Scan all substation equipment in the yard and control house for excessive or abnormal operating temperatures.	Reference Section 11.3 for guidelines for specific equipment classes ①
Transformers	Oil Tests: H_2 equivalent, dissolved gasses, mini-screen.	Oil tests: Within normal operating limits based on type of equipment
Load Tap Changers	Oil Tests: H_2 equivalent, dissolved gasses, mini-screen.	Oil tests: Within normal operating limits based on type of equipment
Oil-filled Instrument Transformers	Monitor and record transformer partial discharge activity and mechanical integrity.	Partial Discharge: Non-detectable
Circuit Breaker Operator Profile	Operate circuit breaker to record critical trip and close operating coil parameters and timing	Trip and close voltages and timing within manufacturer limits and comparable to previous tests

① Temperature rise when compared to similar equipment or other phases.
② H_2 Equivalent: (H_2 and CO Combustible Gas)
③ Operator Profile completed on an annual basis. Not required for low voltage (distribution) breakers.

11.3 Thermography Guidelines

Thermographic surveys will consist of a visual, electrical, and mechanical inspection with equipment designed to detect emitted radiation. Equipment covers should be removed prior to the thermographic inspection. Surveys should be performed during periods of maximum possible loading, if possible. All current-carrying equipment will be inspected.

Discrepancy reports will consist of the following:

a. Time and date of the inspection.
b. Description of the discrepancy.
c. Temperature difference between affected area and the reference area.
d. Suspected cause of the temperature difference.
e. Load conditions at the time of the inspection
f. Photographs and thermograms of the discrepancy.

Equipment Class	Work to be Performed	Acceptance Criteria: Normal Operation
Transformers and Regulators	Scan fan and pumps ① Scan radiators for proper cooling/fluid levels Scan tank for proper fluid level	5-9° C rise: Possible deficiency, continue to monitor 10-25° C: Deficiency exists, prepare report & plan repair, create WO > 25° C: Major deficiency, immediate repair, WO priority 5
Load-Tap Changers	Scan LTC compartment Compare LTC compartment temperature to main temperature at same level	<1° C rise: Possible deficiency, continue to monitor 1-5° C: Deficiency exists, prepare report & plan repair, create WO > 5° C: Major deficiency, immediate repair, WO priority 5
Disconnect Switches and Fuses	Scan disconnect switches at jaw and hinge end ① Scan high voltage terminations ①	5-9° C rise: Possible deficiency, continue to monitor 10-75° C: Deficiency exists, prepare report & plan repair, create WO > 75° C: Major deficiency, immediate repair, WO priority 5
Bushings	Scan all bushing terminals ① Scan entire bushing	> 10° C rise: Deficiency exists, prepare report and create WO >50° C rise: immediate repair, WO priority 5 Internal Bushing Temperature: >3° C rise: Deficiency exists, prepare report and create WO >5° C rise: immediate repair, WO priority 5
Circuit Breakers and Circuit Switchers	Scan tank for temperature & fluid level ①	5-9° C rise: Possible deficiency, continue to monitor 10-25° C: Deficiency exists, prepare report & plan repair, create WO > 25° C: Major deficiency, immediate repair, WO priority 5 Tank Differential Temperature >3° C: Deficiency exists, prepare report & plan repair
High Voltage Terminations	Scan all high voltage terminations Scan all station service transformers	5-9° C rise: Possible deficiency, continue to monitor 10-75° C: Deficiency exists, prepare report & plan repair, create WO > 75° C: Major deficiency, immediate repair, WO priority 5
Low Voltage Control Wiring	Scan all control house wiring, including relay panels, AC/DC panels, ATS, and batteries Scan all equipment control cabinets Scan compressors/pumps in operator ① Scan control cabinet wiring	If 3° C rise exists, correct problem if possible. If correction cannot be made, create follow-up work order.
Instrument Transformers	Scan terminations/fluid levels	5-9° C rise: Possible deficiency, continue to monitor 10-25° C: Deficiency exists, prepare report & plan repair, create WO > 25° C: Major deficiency, immediate repair, WO priority 5

Arresters	Scan stacks and connections	If > 3° C rise exists, major deficiency, immediate replacement WO priority 5
Capacitor Bank	Scan fuses, capacitor cans, and connections.	5-9° C rise: Possible deficiency, continue to monitor 10-75° C: Deficiency exists, prepare report & plan repair, create WO > 75° C: Major deficiency, immediate repair, WO priority 5
Reactor Bank	Scan reactor coils and connections.	5-9° C rise: Possible deficiency, continue to monitor 10-75° C: Deficiency exists, prepare report & plan repair, create WO > 75° C: Major deficiency, immediate repair, WO priority 5

① Temperature rise when compared to similar equipment or other phases.

11.4 Substation Diagnostics Activity Guidelines

(Intervals in months)

Substation Diagnostics Program	**Stations**	**Interval**
Thermography	EHV (345kV) All Others	6 12
Partial Discharge (Oil filled instrument transformers)	EHV (345kV) All Others	6 12
Acoustic Emissions	EHV (345kV) All Others	As needed
Corona Discharge (Night Vision)	All	As required
H_2 Equ. (H_2 and CO Combustible Gas)	EHV (345kV) All Others	6 ① 12
DGA and Mini Screen if due (Main tank/LTC)	EHV (345kV) All Others	12/6 24/12
Battery Testing (Cell voltage, cell impedance, strap resistance, specific gravity, and temperature)	EHV (345kV) All Others	24 24
Circuit Breaker Operator Profile	All	30

① H2 test not required with units that have on-line gas monitors

12.0 Summary of Oil Tests

- H_2 equivalent: combined hydrogen (H_2) and carbon monoxide (CO) content.

- Oil quality
  - Dielectric strength: Transformers per ASTM D-1816
  - Dielectric strength: Circuit breakers per ASTM D-877
  - Moisture: per ASTM D-1533 ①
  - Interfacial tension: per ASTM D-971 ①
  - Acid number: per ASTM D-974 ①
  - Power factor: per ASTM D-924

  ① Portion of Mini-screen test

- Dissolved gasses
  - Hydrogen (H_2): Indicates partial discharge activity
  - Methane (CH_4): Indicates heating of oil >150° C
  - Acetylene (C_2H_2): Indicates severe heating/arcing under oil (>700° C)
  - Ethylene (C_2H_4): Indicates heating of oil >500° C
  - Ethane (C_2H_6): Indicates heating of oil >300° C
  - Carbon Monoxide (CO): Indicates degradation of paper insulation
  - Carbon Dioxide (CO_2)

13.0 Substation Inspections (Routine Patrol)

Substation inspections are conducted to perform visual inspections and record operational data from equipment. The list below contains general guidelines for routine substation inspection items.

Substation Inspections

Inspection Item	Work to be Performed
General Conditions	1. Cleanliness; Corrosion problems; Indications of overheating or mis-operation; Abnormal position or alignment
Substation Property	1. Fences & gates secure; Vegetation; Drainage and/or erosion problems; Vandalism; Gate locks/chain in place; Yard lights operating correctly; 2. Danger signs visible on gates and fences, replace missing signs; 3. Verify equipment ground connections on fences and structures; 4. Inspect electric fences
Control House	1. House AC and DC lights operating; Hot sticks in house; 2. Fire extinguisher available and inspected; 3. Telephone operating correctly; Emergency telephone numbers posted; 4. MSDS and SPCC books available; Substation drawings available; 5. Air conditioner/heater operating properly;
Battery/Battery Charger	1. Cleanliness; Eyewash station full; 2. Verify proper electrolyte levels and add distilled water as necessary, if water is added equalize the battery bank for 12 hours; 3. Check for damaged or cracked cells or leakage of electrolyte; 4. Check for evidence of corrosion at terminals, connectors, and posts; 5. Check overall bank voltage and temperature 6. Verify proper float/equalize settings on battery charger; Record volt/amp readings; 7. Verify battery rack ground connection; 8. Check for DC ground
Relay Equipment	1. Equipment tags visible; Inspect for physical damage; 2. Record and reset all relay flags; Report any flags to System Control Services;

Oil Circuit Breakers	1. Equipment tags visible; Evidence of oil leaks; Check oil containment area; Drain water if no oil sheen present. 2. Check proper oil level in each tank and bushings; 3. Record operations counter reading and motor run time meter reading; 4. Record fault operations; 5. Check hydraulic/air pressure in operating mechanisms; 6. Check hydraulic fluid levels and air compressor oil levels; 7. Check cabinet heaters; 8. Verify equipment ground connections;
SF6 Circuit Breakers and Circuit Switchers	1. Equipment tags visible; Evidence of gas leaks; 2. Check proper SF6 operating pressure; Add SF6 if necessary. 3. Record operations counter reading and motor run time meter reading; 4. Record fault operations; 5. Check hydraulic/air pressure in operating mechanisms; 6. Check hydraulic fluid levels and air compressor oil levels; 7. Check cabinet heaters; 8. Verify equipment ground connections;
Transformers	1. Equipment tags visible; Evidence of oil leaks; Check oil containment area; Drain water if no oil sheen present. 2. Check proper oil level in main tank and bushings; 3. Record max & present temperature on winding temperature gauge, reset draghands; 4. Record max and present temperature on oil temperature gauge, reset draghands; 5. Record nitrogen pressure on main tank; 6. Record nitrogen pressure on nitrogen bottle, replace bottle if < 400 psi 7. Record hydrogen monitor reading, if equipped; 8. Verify equipment ground connections on tank and arrestors; 9. Function check all cooling fans/pumps for proper operation; 10. Check desiccant breathers for discoloration and replace desiccant as necessary;
Load Tap Changers and Regulators	1. Equipment tags visible; 2. Check proper oil level in tank; Evidence of oil leaks; 3. Record operations counter reading; 4. Record readings from LTC temperature differential monitors, if equipped; 5. Record minimum/maximum LTC position indicator and reset draghands; NOTE: If LTC has not operated through the neutral position, then manually operate through neutral, if possible, otherwise note on inspection report. 6. Check desiccant breathers for discoloration and replace desiccant as necessary;
Air Switches	1. Equipment tags visible; Check locks on switch; 2. Verify equipment ground connections on switch pads; 3. Visually check switch alignment and insulators for damage; 4. Remove bird nests, if safe.
Surge Arrestors	1. Equipment tags visible; Evidence of equipment damage; 2. Verify equipment ground connections;
Capacitor Banks	1. Equipment tags visible; Evidence of oil leaks; 2. Check for blown fuses; 3. Inspect for damage, corrosion problems, indications of overheating or misoperation; 4. Verify equipment ground connections;
Reactor Banks	1. Equipment tags visible; 2. Inspect for damage, corrosion problems, indications of overheating or misoperation;
Instrument Transformers	1. Evidence of oil leaks; Check proper oil level in device; 2. Inspect for damage, corrosion problems, indications of overheating or misoperation; 3. Verify equipment ground connections;

Substation Structures	1. Verify equipment ground connections on fences and structures; 2. Inspect for missing or loose structure anchor bolts; 3. Inspect for damaged or contaminated insulators; 4. Inspect structure foundations for damage and cracks; 5. Inspect bus for loose/missing hardware;
Automatic Throwover Switches	1. Equipment tags visible; 2. Inspect for damage, corrosion problems, indications of overheating or misoperation; 3. Verify equipment ground connections;
Generators	1. Check proper fuel, oil and water levels; Evidence of any leaks; 2. Inspect air filter and block heaters; 3. Record battery voltage and hour meter reading;

14.0 Mobile Transformers, Regulators, and Portable Cables

14.1 Description

Mobile transformers are vital to the overall operations and maintenance functions of Transmission Services facilities. Due to inherent safety risks and wear-and-tear, they demand special safety and maintenance criteria.

14.2 Portable Cables:

Micro-Ohm Tests

- ❑ Measure shield resistance

DC Hi-Pot Tests

- ❑ Accepted industry test methods:
  - Test cable per IEEE Std. 400-1991
  - Test cable per Doble standard (Recommended)

Energization Test: Tests to be performed prior to energization
After verifying that all cables and potheads are in good physical condition, energize cables for a minimum of 60 seconds prior to picking up load on cables. ***NOTE: All personnel should maintain a safe working distance from cables during this energization test.***

14.3 Mobile Substation Maintenance Activity Guidelines

(Intervals in months)

Mobile Substations	Interval
Transformer:	
DGA + mini ① (for units without hydrogen monitors)	12
DGA not necessary for units with hydrogen monitors	N/A
Insulation/PF Tests	36
Auxiliary Equipment ②	72
LTC:	
DGA+mini ①	12
Disassembly + Controls + Auxiliary Equipment ③	72
Regulator:	
Power Factor Tests	36
Power Circuit Breakers:	
Operating Mechanism	36
Disassembly + Controls + Auxiliary Equipment	72
Circuit Switchers:	
Contact Resistance + Comprehensive Maintenance	72 / 250 Op / 5 F
Interrupter Replacement	As Required
Relays:	
Functional and Calibration Tests	36
Hydrogen Monitor	36
Batteries:	
Cell Voltage + Cell Impedance + Strap Resistance + Fluid Level	12
Capacity Test	As Required
Fluid Level	Performed during every installation
Cables:	
Micro-Ohm Resistance	12
DC Hi-Pot Test	12
Energization Test	Performed during every installation
Grounds:	
Check for tightness and resistance	36
Structural Components:	
Check entire structure for loose, worn, rusted, and damaged components	36
Trailer:	
Check lights, tires, brakes, axle bearings, hitch, and overall condition	Before each move; 12 month Detailed inspection

① Consists of Dissolved Gas-in-oil Analysis (DGA) and oil mini-screen which includes moisture-in-oil tests (D-1533), IFT (D-971), and acid number (D-974). Sample should be taken while unit is in-service.

② Auxiliary equipment includes gages, indicators, alarms, sensors, pumps, fans, arresters, power fuses, etc.

③ Auxiliary equipment includes gauges, indicators, alarms, sensors, etc.

F Number of Fault Operations

Op Number of Mechanical Operations

15.0 Substation Insulated Sticks (Hot Sticks, Shotguns, etc.)

- ❑ Inspect for general condition, serviceability, worn parts, damage, cleanliness, and signs of electrical arcing or tracking

- ❑ Hi-pot test per IEEE Std. 978 as per current standard

Substation Insulated Sticks (Hot Sticks, Shotguns, etc.)
(Intervals in months)

Insulated Sticks ①	Inspect for Damage, Condition, etc.	Hi-Pot Test ②
Insulated Sticks	Each Use	24

① Applies to all insulated sticks remaining in substations for use by multiple parties.

② Test per IEEE Std. 978 as per current standard

16.0 Miscellaneous Equipment

16.1 Description

Preventive maintenance is conducted on miscellaneous substation equipment to insure their continued operational reliability. This equipment includes generators, control house equip., structures, etc. the maintenance consists of routine equipment inspections and diagnostic testing. The intervals and acceptance criteria shown below are general guidelines.

16.2 Inspections

Routine inspection and minor maintenance items are detailed in Section 13.0 of this appendix.

16.3 Diagnostic Testing

Routine diagnostic items are detailed in Section 11.0 of this appendix.

16.4 Maintenance Activity Guidelines

Equipment	Work to be Performed
Generators	Service Engine; Replace Oil & Filters; replace belts & hoses as needed; inspect/replace block heater & fuel lines as needed; inspect/repair exhaust system & fan; inspect for leaks (fuel, oil, water); overall condition of unit; overall condition of enclosure if present
Auto Transfer Switch	Clean out the enclosure of any dust, dirt or moisture; inspect contact condition; lubricate all movements and linkages if subjected to severe dust or abnormal operating conditions

Appendix C: Guidelines for Transmission Line Patrol

1.0 Patrol Frequency

All 69 kV, 138 kV, and 345kV lines should be patrolled once every 6 months, 12 month or 18 months depending on conditions; situations such as weather or recurrent tripping may warrant more frequent line patrols. The LCRA TSC Line Importance List will be used to determine frequency. Table C1 provides recommendations for determining line patrol intervals.

Table C1. Recommendations for Transmission Line Patrol Intervals.

Priority	Patrol Intervals (Months)	General Criteria--Line conditions best fits:
High	6	* Primary source feeders * Heavily loaded lines * Lines with a history of significant maintenance problems * Lines that are radial * Lines that originate at power plants * Lines in populated areas with concerns about: - Safety - Encroachment - Property damage - High visibility
Moderate	12	* Multi-feed lines * Moderately loaded lines * Lines with a history of moderate maintenance problems * Lines in rural areas * Recent overhaul/ten year inspection (past 5 years)
Low	18	* Multi-feed lines * Lightly loaded or de-energized lines * Lines with a history of minimal maintenance problems * Lines in rural areas * Recent overhaul/ten year inspection (past 3 years)

Appendix D: Transmission Line Facilities Inspection and Maintenance Procedures

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1.0 Line Patrol Procedures

A Line Patrol Report should be completed during the patrol to record general conditions (Ref Table D1 for sample patrol report). The inspection should address, at minimum, the following:

Inspection Item	Work to be Performed
Tower Conditions	1. Check tower footings for cracks, loose/bent/missing hardware, and overlying dirt or debris (remove as needed). 2. Check for soil erosion around tower and H-frame footings. 3. Check tower for loose/bent/missing/rusty steel members and bolts.
Line Clearance	1. Refer to Table D2 for acceptable clearances (measure conductor if needed)
Conductor and Shield Wires	1. Check condition of conductors/static for damage due to vibration, gunshot, broken strands, rust, etc. 2. Check condition of vibration dampers. 3. Check condition of spacers in bundled conductors. 4. Check for abnormal conductor sag. 5. Check for broken ground leads on OPGW.
Insulators	1. Check insulators for damage, signs of flashover. 2. Check insulators for contamination due to buzzards, dust, dirt, etc (identify if contamination is light, medium, or heavy). 3. Check for blown line arresters. 4. Check for keys missing/backing out. 5. Check for missing insulator covers or deterrents where applicable. 6. Check for correct number of insulator bells (Refer to Table D3).
Structure Hardware	1. Inspect tower and H-frame structures for loose or missing nuts, bolts, cotter keys, pins, etc. 2. Inspect towers for loose anchor bolts (tighten as needed). 3. Inspect for bent/rusting steel structural members. 4. Inspect structures for line number signs and danger signs attached on opposite sides of structure and visible from under the line(s) (T-XXX) (install/replace as needed during the patrol). 5. Inspect logo signs that should be installed on structures at roads on the structure closest to the road (replace as needed during the patrol). 6. Verify 1st structure at substation and structures at road crossings have correct line number (add numbers as needed during the patrol). 7. Verify structures with multiple lines have multiple line identification numbers attached (add numbers as needed during the patrol).
Ground Wires	1. Check that ground wire is securely connected to the wood pole for its entire length. 2. Check that ground wire is securely fastened from structure to earth-ground (each leg shall be grounded). 3. Check that the ground is secured to OPGW hardware. 4. Check for broken or missing grounds on structures (repair those that can be done so safely during the patrol).
Guys and Anchors	1. Check anchor rods and guy wires for looseness, rust, and dirt/debris over anchor (*if action is required identify size of wire*). 2. Remove overlying soil near anchors to keep anchor eyes above soil level. 3. Check for missing or damaged guy guards in public areas (install as needed during the patrol).
Poles	1. Check poles for internal damage by striking with hammer and listening for hollow sounds. 2. Inspect around ground line and check for ground line decay. Probe with screwdriver or other tool to determine wood soundness. 3. Check poles for woodpecker damage and identify size and location. (Install additional hardware cloth to the bottom of poles if needed.)
Cross-arms	1. Inspect cross-arms for rot, cracks, and major woodpecker holes (identify location).
X-braces and Knee-braces	1. Inspect X-braces and knee braces for rot, cracks, and major woodpecker holes (identify location).