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TRANSMISSION AND DISTRIBUTION

Substation Operations and Maintenance Policy and Procedures (SOM)

November 22, 2024

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Southern California Edison
Standards and Publications
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Substation Operation and Maintenance Policy and Procedures (SOM) Manual

Revision Summary

Effective Date: November 22, 2024

Summary of Revisions

Table QRS–1 lists and describes the revisions made to the Substation Operation and Maintenance Policy and Procedures (SOM) Manual. Table QRS–2 defines manual revision types.

Table QRS–1: SOM Manual Revisions

Policy	Sheet & Revision Date	Description	Type
SOM-MT1	Sheet 2	Revised section 6.1 to add a note on the frequency requirements for equipment with online DGA monitoring equipment. Revised section 6.2 to remove reference to 2 year interval testing.	Technical
SOM-MT4	Sheet 3	Added Internal Fault Detectors (IFDs) Section 4.3 A Note.	Technical

Table QRS–2: Definitions of Revision Types

Type	Definition
Admin	These are policy and procedure changes that do not require Standards Review Team (SRT) or management approval. These revisions are identified in Table QRS–1.
Technical	Technical revisions are policy and procedure changes that require SRT and management approval. These revisions are identified in Table QRS–1.
New	New policies and procedures. New policies are identified in Table QRS–1.

Getting Help

Click on a name to send an e-mail to that person, or call at the numbers provided.

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Director | Asset Management Program

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Section R: References

Division Order Index Number	Division Order Title	New SOM Section	New SOM Document Name
Policy	Policy (7/98)	General	G1
Index	Index (5/01)	Table of Contents	TOC
10. 00	Personnel (Section Title Only - No Content)	N/A	N/A
10. 10	Transmission/Substation Personnel (7/13/98)	Personnel	P1
10. 20	Employee Notification of Absence (7/14/98)	Personnel	P2
10. 30	Vacant	N/A	N/A
10. 40	Vacant	N/A	N/A
10. 50	Vacant	N/A	N/A
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10. 70	Vacant	N/A	N/A
10. 80	Vacant	N/A	N/A
20. 00	Tools (Section Title Only - No Content)	N/A	N/A
20. 10	Tools and Tool Identification (7/16/98)	Tools	T2
20. 20	Vacant	N/A	N/A
30. 00	Other Departments or Divisions (Section Title Only - No Content)	N/A	N/A
30. 10	Notification of Interruptions and Hazards (10/98)	General	G7
30. 20	Vacant	N/A	N/A
30. 30	Checking Procedure for Work in Substations Other Than Switching (11/95)	Safety and Fire	SF6
30. 40	Vacant	N/A	N/A
30. 50	Routine and Emergency Communications (10/98)	General	G6
40. 00	Operating (Section Title Only - No Content)	N/A	N/A
40. 10	Switching Order - O.D. 245 (7/98)	Operating	O1
40. 20	Use of the Qualified Switching Checker (5/99)	Operating	O2
40. 25	500kV Substation Switching (5/01)	Operating	O8
40. 30	Power Fuses (6/82)	Equipment	E4
40. 35	Transmission Line Routine Patrol, Inspection, Scheduling and Record Keeping (9/00)	Removed	Removed
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40. 45	Line Phasing Procedures (5/93)	Maintenance & Testing	Removed
40, 50	Loading of Distribution Power Transformer Banks (9/99)	Operating	O4
40. 55	Minimum Trips of Equipment and Line Protection (4/13/94)	Operating	O3
40. 60	Operation of Circuit Regulators (6/26/86)	Operating	O8
40. 65	Metal Clad or Cubicle Gear Circuit Breakers (1/01)	Equipment	E5

Division Order Index Number	Division Order Title	New SOM Section	New SOM Document Name
40. 70	Substation Logs (5/94)	General	G–5
40. 80	Out-of-Service Line Sections (6/95)	Equipment	Removed
40. 90	Re-energizing Distribution Power Transformer Banks Following a Relay Operation (3/82)	Operating	O–5
40. 95	Emergency Power Systems (12/99)	Equipment	E–3
50. 00	Maintenance (Section Title Only - No Content)	N/A	N/A
50. 10	Predictive Maintenance Circuit Breakers and Switches (4/99)	Maintenance & Testing	MT–3
50. 20	Relay and Equipment Tests (12/06)	Maintenance & Testing	MT–2
50. 30	Washing Energized Insulators in Substations (12/82)	Maintenance & Testing	MT–5
50. 35	Washing Insulators on Energized Lines (8/96)	Maintenance & Testing	Removed
50. 40	Vacant	N/A	N/A
50. 45	Vacant	N/A	N/A
50. 50	Transformer, Regulator, and Oil-Filled Reactor Maintenance (4/99)	Maintenance & Testing	MT–1
50. 55	Vacant	N/A	N/A
50. 75	Transmission Line Programming Procedures (8/96)	Removed	Removed
50. 90	Replacing Suspension Insulators on Energized Lines (3/82)	Removed	Removed
50. 95	Procedures for Work on Multicircuit 66kV Bridge Type Towers (3/82)	Removed	Removed
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Division Order Index Number	Division Order Title	New SOM Section	New SOM Document Name
70. 35	Vacant	N/A	N/A
70. 40	Live-line Tools (1/1/99)	Tools	T–1
70. 50	Vacant	N/A	N/A
70. 55	Vacant	N/A	N/A
80. 00	General (Section Title Only - No Content)	N/A	N/A
80. 10	Written Instructions and Procedures for Substations (3/82)	General	G–2
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Section G: General

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G1: Substation Operation and Maintenance Policy and Procedures (SOM) Policy

1.0 Purpose

The Substation Operation and Maintenance Policy and Procedures (SOM) details policies, procedures, and practices for substation personnel to follow in the performance of their duties.

As with all other company documents, all employees are expected to comply with the policies, procedures and practices set forth in this manual. These other documents include but are not limited to the following:

- Corporate policies
- Accident Prevention Manual (APM)
- System Operating Bulletins (SOBs)

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G2: Standard Station Instructions (SSI) and Other Substation

1.0 General

1.1 Safety of personnel in substations is of the utmost importance; therefore it is imperative that all substation documentation be accurate and it should address the normal station status, in order for personnel to perform work and to switch in a safe and effective manner.

1.2 The Standard Station Instructions (SSI) shall consist of a Whom to Call form, a copy of System Operating Bulletin (SOB) 600, the SSI bulletin documents, procedures detailing specific operating instructions pertaining to lines, equipment and customers to that station, miscellaneous information, and a One Line for Operation drawing. Reference SOM G–3: Station Prints for detailed OLO instructions.

1.3 Electronic files of the Whom to Call form, SSIs, pre-approved switching procedures, and associated documents shall be kept and maintained in the Substation Documentation Management System (SDMS). Station As-Built prints and the station One Line for Operation drawing shall be kept current in the Corporate Drawing Management Library (CDM). Any document that does not reside in SDMS or any drawing that does not reside in the CDM Library shall be considered incomplete and/or out of date.

1.4 Printed copies of the most up-to-date documents and One Line for Operation prints shall be kept at the jurisdictional Switching Center, as well as at the respective unattended substation. Copies of the most up-to-date station As-Built prints shall be kept at the respective unattended substation.

1.5 Abbreviations in the SSI book shall be restricted to those that are commonly used in substations

2.0 Whom to Call (PSSUD-51) Form

2.1 The Whom to Call (PSSUD-51) form shall be kept as the first page in the SSI book so that in the event of an emergency it may be easily located.

2.2 The Whom to Call form shall be updated on an as needed basis, as information changes only.

2.3 The Whom to Call form will instruct employees to call 911 in the event of a serious injury or accident. The form shall include the station name, address (if available) and phone number, GPS coordinates, location of the nearest public telephone (if applicable), the jurisdictional Switching Center and phone number, Grid Control Center phone number, and the nearest designated medical facilities.

3.0 System Operating Bulletin 600 (SOB 600) and Operating Procedures

Copies of any SOBs and any associated Operating Procedures detailing specific operating instructions pertaining to lines, equipment and customers to that station shall be placed second in the SSI book.

4.0 Standard Station Instruction Bulletins

4.1 A complete and accurate set of SSIs is critical for maintaining a safe work environment in substations. Each substation on the SCE electrical grid shall contain a complete, accurate, and approved set of SSIs. The electronic SSI documents shall be kept and maintained in SDMS.

4.2 The SSI documents shall be brief, concise, and applicable to doing work and switching in substations. SSIs shall provide guidance and understanding to the Acting Operator during routine and emergency conditions.

4.3 The SSIs shall be written in a template format. The questions requested in the templates shall be considered the minimum amount of information necessary for a complete and accurate set of SSIs.

4.4 The Operations Supervisor is responsible for the initial writing of the bulletin template document as well as any/all future updates to the documents. In addition, he/she will be responsible for approving the documents.

4.5 The SSIs shall be comprised of 12 bulletin sections. Each bulletin section may have multiple document types in order to address the various types of equipment found within a respective substation. These various document types shall be designated by the letters A, B, C, etc. and accompanied by an associated number, which shall be defined during development. If a particular bulletin document does not apply at the respective substation, the document will not be included in the SSIs.

4.6 The bulletin header information shall contain the substation name, the jurisdictional Switching Center name, the bulletin number, section, and number identification, the title of the document, the new date, and the date of the old document being replaced.

4.7 Please see Attachment A (SSI General Template Inventory - Table of Contents) at the end of this policy for a complete list of the bulletin section titles, as well as the various section letters and numbers. Here is an overview of the bulletin section titles:

A. Bulletin 1 — SSI Table of Contents

Provides an overview list of the bulletin documents included in the respective set of SSIs. Specific document information may be found in the various Section Contents Lists that exist for each bulletin section.

B. Bulletin 2 — Dispatching

Contains specific administrative information regarding the respective substation; such as, the address, jurisdictional information, phone contact information, normal station status and configuration.

C. Bulletin 3 — Safety and Environmental

Identifies specific safety and environmental hazards that exist at the respective substation, as well as information on how to avoid the hazards and what to do in the event an employee is exposed to one of the hazards.

D. Bulletin 4 — Auxiliary Equipment

Addresses all of the other equipment that exists in the respective substation that is not addressed in one of the other bulletin sections.

E. Bulletin 5 — Transformers

Provides specific information about the various types of transformers that exist at the respective station; such as power transformers, ground/condenser transformers; potential transformers, etc.

F. Bulletin 6 — Circuit Breakers, Switchers and Specialized Switchgear

Provides specific information about the various types of circuit breakers, switchers, and other specialized switchgear that may exist at the respective substation.

G. Bulletin 7 — Battery & Charging Equipment

Provides specific information about the battery and charging equipment at the respective substation.

H. Bulletin 8 — Ground Detecting

Address all AC and DC ground detecting equipment identified at the respective substation.

I. Bulletin 9 — Fire Equipment

Addresses all of the various fire-fighting equipment located at the respective substation.

J. Bulletin 10 — Relays

Provides specific information about the various relays and schemes identified at the respective substation.

K. Bulletin 11 — Automation & Alarms

Addresses the type(s) of supervisory control, alarms received (not addressed in any other bulletin), and the communication facilities for the respective substation.

L. Bulletin 12 — Voltage & Var Control

Provides specific information about the various types of voltage and var equipment at the respective substation.

4.8 The jurisdictional Operations Supervisor will be responsible for completing the SSI documents for all bulletins, including any/all future updates to the documents.

A. The Operations Supervisor will address the assigned documents mentioned above by providing the requested information in the bulletin templates.

B. When a supervisor has finished entering the requested information into the bulletin template, he/she shall share the document (via SDMS) to the SSI Review email address, which is managed by SC&M.

C. The SC&M support resource will initiate the document for approval to the responsible supervisor.

D. The Operations Supervisor will review the document, note the date, and approve the document if they agree with any changes that may have been made.

E. At this point the document is considered approved. The Operations Supervisor shall then print the new document and place one copy in the Switching Center SSI and another copy in the unattended substation SSI.

5.0 Station Procedures

There are various types of pre-written, pre-approved procedures that may be found at a respective substation. These procedures may be located directly behind the SSI bulletin documents, or kept in a separate book.

5.1 Circuit Breaker Analysis (CBA) procedures

5.2 Circuit Breaker Clearing (CBC) procedures

5.3 Station Hot/Cold Wash procedures

5.4 SAS Menu Trees

5.5 SAS Logic Flow Diagram

6.0 Miscellaneous Information

Any information deemed important to the operation of the substation shall be kept directly behind the procedures section, or may be kept in another book.

7.0 One Line for Operation drawing

The One Line for Operation drawing shall be placed last in the SSI book and/or it may be displayed somewhere in the station that is easily accessible. The One Line for Operation drawing is an important tool in ensuring the safety of all personnel and must be kept current and accurate as work is completed. Please refer to the Substation Operation and Maintenance Policy and Procedures Manual (SOM), Policy G–3: Station Prints.

G3: Station Prints

1.0 General

1.1 Station prints are a vital tool in the operation and maintenance of each substation. Therefore, it is important that all prints be accurate and stored in a manner that will preserve them and allow them to be readily available for use at all times.

1.2 Substation Operation Supervision is responsible to see that all prints in his/her assigned area are properly filed and stored on-site at every station. He/she is responsible for providing a location to store station prints on-site and to see that the One-Line for Operations is maintained and kept up to date.

1.3 Substation Test Supervision is responsible to see that all electrical prints in his/her assigned area are maintained and up to date. For the reliability of the electrical grid and the Safety of personnel, it is imperative that the electrical prints in substations be maintained to reflect the exact configuration or design of the electrical systems contained in the substation.

1.4 When work is performed that requires changes to the station prints, the work group involved in the work shall be responsible for updating the prints by following the guidelines set forth in this policy.

1.5 In order to prevent errors the corrections shall be legible, using standard symbols. Use a red pencil for all additions or changes. Draw a green line through the portion to be deleted. Any instructions or comments shall be written in blue pencil.

2.0 "One Line for Operation" Print

2.1 Every station must have an up to date "One Line for Operation" print kept either in a frame on the wall or in the Standard Station Instructions book (SSIs). Since this print is used to trace power flow and check switching in Pre-Switching technique, it is imperative that this print be maintained and accurate at all times.

2.2 The One Line for Operation print should be the same as the One-Line for Construction with the following changes:

A. The title "One Line for Operation" shall be used, as well as the print and revision number of the present One Line for Operation.

B. Add the circuit breaker number to all 500 and 220 kV CBs as per System Operating Bulletin No. 84.

C. Add the bank ampacity table.

D. Conductor / Bus size

E. Add the trip and reclose schedule or SAS Functions and Flow Diagram.

F. Table of IEEE references being used.

G. Add notes as necessary.

2.3 When a construction project is being performed at a station, it is the responsibility of Operations to update the on-site One Line for Operation once equipment has been energized and prior to leaving the station. Operations will then copy the information from the station to assist in updating the copy at the Switching Center. Once all work is completed on the project, Operations will send in the revised One Line for Operation to Engineering for update. For large projects it is acceptable to use an accurate One Line for Construction print until proper corrections can be made to the One Line for Operation.

2.4 For Construction projects that have multiple moves, the One Line for Operation shall be maintained by Operations throughout the moves of the project, manually updating on a daily basis as required. Once the overall project is complete a corrected print will be sent into Engineering to update the One Line for Operation.

3.0 Electrical Prints

When a print package is received for a construction project the Test Technician assigned to the project should review the electrical elementary diagrams and compare them to any applicable engineering standards for accuracy. Any changes will be communicated to Engineering for approval. The wiring diagrams shall then be compared to the elementary diagrams and any reference material for accuracy.

One complete and accurate set of prints shall be maintained at the substation during construction. When changes are made the existing station prints shall be marked up or replaced with prints that show accurate station status. This will help eliminate confusion if someone unfamiliar with the station is called in to work at the station. At the end of the project the Test Technician shall create a second set of prints by making copies, scanning, or hand mark ups. This second set will be used to send in to Engineering for revision.

4.0 Revisions to As-Built Prints

4.1 At the end of the project the Test Technician shall review the marked-up drawings and process the revisions as follows:

A. The first set of prints will be left at the station, and all superseded prints shall be removed. The new set of prints will remain at the station until the as-built print package returns from Engineering.

B. The second set of prints will be sent in to Engineering as the as-built print package per the Engineering and Substation As-Built Process and marked with the Job Name, Test Technician Name and the Work Order Number.

C. Every effort should be made not to leave the substation without updating station prints to reflect any changes made. If it is not possible to update the station prints with the current changes before leaving the substation, the Test Technician will indicate on the existing station prints in red that these prints are not the most current and where to locate the latest copy.

D. Every effort should be made to have one set of updated prints in the substation at all times. If multiple sets of prints are in the substation then the accurate set of prints shall be clearly identifiable.

4.2 All revisions large or small will be sent in to Engineering per the Engineering and Substation As-Built Process. This is so future projects will be designed on the most accurate version of what exists in the substation.

4.3 If work is performed at a station and a Test Technician is not involved, the work group performing the work is responsible for submitting the as-built prints to Engineering per the Engineering and Substation As-Built Process.

4.4 Revisions made to drawings after the Job Order has been closed will be classified as a Record Revision change. A note will be placed in the revision block followed by a brief description of the change, e.g., "RECORD REVISION- REVISED LINE NAMES". Two copies will be made; one will be kept with the station prints, the other will be sent to Engineering. All revisions shall be made after a job is completed and is the responsibility of the individual doing the work.

5.0 Revisions of As-Built Prints Returned from Engineering

5.1 Once the revised as-built print package is received from Engineering, the Test Technician shall have 30 days in which to take the revised print package to the substation per the Engineering and Substation As-Built Process.

5.2 It is the responsibility of the individual replacing the prints at the station to carefully review all changes made by comparing the new print to the marked up print at the station. Once the print is verified as accurate, place the new print in the station file and remove the marked up print.

6.0 Working Outside Normal Area of Responsibility

When a Test crew is assigned to a project outside their own AOR they shall follow all print handling guidelines. Once the project is complete the Test crew shall schedule a formal hand-off meeting with the local Test crew to hand over all paper work and to formally discuss the changes made at the station. This hand off meeting will help eliminate any confusion and keep the local Test crew responsible for the station in the loop.

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G4: Radio Protocol

1.0 Purpose

Radio communication during work on SCE facilities is essential in maintaining consistency in systems operations, and enhancing the safety of SCE employees. Using proper radio protocol ensures an effective means of exchanging information between substation and construction and maintenance (C&M) crews, troublemen, distribution operation center (DOC), and Switching Center is maintained. This communication is vital in achieving operational excellence.

2.0 Guidelines

2.1 Daily Radio Check with the Switching Center and Doc

A. At the beginning of each workday, or upon arrival at the job location, a radio check shall be made with the switching center and DOC. Substation crews need only radio check with the switching center. This will verify that radio communication is working.

B. Whenever a crew is going to operate energized high voltage switching equipment, or line taps and branch line fuses, they shall contact the switching center from the job location. They shall provide the system operator with their location, a description of the work they will be doing, and any resources needed.

2.2 Off Hours Radio Check with the Switching Center

A. When a crew works off hours, a radio check shall be made with the switching center and DOC at the beginning of the shift. Substation crews need only radio check with the switching center. This will verify that radio communication is working.

B. Whenever a crew is going to operate energized high voltage switching equipment, or line taps and branch lines fuses, they shall contact the switching center from the job location. They shall provide the system operator with their location, a description of the work they will be doing, and any resources needed.

C. When a crew has completed their work, they shall notify the switching center and DOC that they have completed their work and are going home. Substation crews need only notify the switching center.

2.3 Out of Region Assignment

A. When a crew is temporarily assigned to work in another region, a radio check shall be made with the switching center and DOC on the talk group for the region which they are assigned. This will verify that radio communication is working. They shall also monitor the switching center and DOC talk group for that work area.

B. When the crew's temporary assignment is completed, they shall notify the switching center and DOC that they are leaving the area for their home base or another assignment.

2.4 SOB 301 — Communications

When speaking with a switching center operator, it is imperative that formality be maintained with concise and professional communications at all times. Part of this communication process is to ensure proper information is given. To check this, it is incumbent upon the person receiving the clearance, switching or no test order, to repeat it back to the switching center operator.

The 900 MHz radio shall be utilized for all switching orders using the appropriate Substation talk group frequency. The cell phone shall only be utilized with approval from the switching center system operator.

2.5 When operating energized equipment 2.4 kV and above, radio contact must be made with the switching center in accordance with APM, Rule 704.

2.6 When an emergency or circuit interruption at the work site occurs:

A. Transmit on a talk group where others will hear you.

B. If you are unable to obtain a talk permit due to a busy signal, press the emergency button on top of the radio.

C. In a calm and normal tone of voice, provide the following information:

1. Who you are
2. The nature of the emergency
3. The location of the emergency
4. What assistance is needed (for example, ambulance, fire department, and so forth)

G5: Substation Logs

1.0 General

1.1 A log is a business record of the events affecting SCE personnel and equipment. Every substation shall maintain a log book. Each substation log book shall have entries to include the routine and emergency operations of that station. The switching center log shall also include entries pertaining to the operation of all circuits and equipment under the jurisdiction of the respective switching center. In addition, entries are to be made detailing any unusual information regarding SCE employees, property, or equipment, as well as pertinent information concerning non-SCE personnel who may be involved in any incident affecting SCE facilities and/or interests. Refer to SOM G2: Standard Station Instructions (SSI) and Other Substation for more information.

1.2 It is imperative that all the information concerning every entry be thorough, legible, and understandable. For this reason, logging of switching operations will include a statement detailing the reason for the switching.

2.0 Instructions for Switching Center Logs

2.1 The log sheet provides spaces for the name of the switching center, the date, the page number, and the time of entry. The date shall be entered with the month first, followed by the day and the year. Numbers may be used for this purpose. The time will be entered by reference to the 24-hour clock.

2.2 All entries, other than those regarding clearances, personnel at work and margin symbols, shall be entered in black.

2.3 The first entry of each day shall be entered at 0001 hours. This entry shall state the names of the System and Substation Operators who are remaining on shift, and a statement documenting that the Control Room NERC CIP Visitor Log Book has been reviewed for accuracy and completeness.

2.4 After this entry, other entries made during the day need not be in chronological order. For purposes of clarity, it will be preferable in many instances to enter all information regarding a particular piece of equipment or program and then initiate another entry.

2.5 An interruption log sheet should be used to record all unplanned operations under the Switching Center's jurisdiction. This practice is required to assist in ensuring that these reports are initiated for every event. The interruption log of the sheet shall be used to log required entries of fault conditions and the necessary switching involved. The interruption log sheet shall also state any pre-existing abnormal condition.

2.6 Entries concerning field switching or switching at another station require a heading indicating where the ensuing switching occurred.

2.7 At the end of each day the individual log sheets, switching procedures, abnormal log sheet, and interruption log sheets will be arranged in an order that provides for maximum readability. The completed sheets will then be placed in a binder or folder. When the binder or folder is full, it shall be marked with the station name, range of dates covering enclosed documents and transferred to a local storage area for a period of one year from the last dated entry. After one year, the documents shall then be transferred to the Corporate Record Center.

2.8 The four approved daily log forms are listed below:

- Log Sheet
- Switching Procedures
- Abnormal Log Sheet
- Interruption Log Sheet

3.0 Unattended Station Logs

3.1 Spiral ringed log books are provided for log entries at unattended stations. All handwritten entries shall be legible. All entries, other than those regarding clearances, personnel at work, and margin symbols, shall be entered in black. Clearances, Personnel at Work, and Personal Grounds entries shall be placed in the "Clearances, Personnel at Work, and Personal Grounds Log book." Incorrect entries shall be cancelled by drawing a single line through the entry. The employee making the correction shall initial adjacent to the single line.

3.2 After switching has been completed, a statement shall be entered in the unattended log book that shall identify:

- Switched equipment
- Why it was switched
- Status of switched relay protection including rotos, potential secondary, pilot wire/communication disconnects and circuit breaker bypass knife switches
- Status of ground disconnects

This statement shall reflect the time the switching was completed.

3.3 When a new log book is started, the previous log book, used as a reference, shall be retained at the local substation for one year from the last dated entry. After one year, the log book shall then be transferred to the Corporate Record Center. When a log book starts to deteriorate, it shall be replaced with a new log book.

4.0 Clearances and Personnel at Work

4.1 Clearances shall be entered in the Main Log at the Switching Center and in the "Clearances, Personnel at Work, and Personal Grounds" Log book at unattended substations as specified in the *Accident Prevention Manual* (APM). In addition to the APM rules, the following rules shall apply:

- The name of the party receiving the clearance should not be entered below the clearance entry unless it is the signature of the party receiving the clearance.
- The release of the clearance shall be entered on the same page on which the clearance was entered and there shall be no intervening entries between these entries.
- If a clearance is released and the associated equipment is not ready for service, the words “Not Ready for Service” shall be included in the body of the release in blue. In addition, a statement will be included in the general log stating the reason for this status.

4.2 When a line or line section has been cleared for work, all stations at terminals of the line, or line section, will be notified by the switching center or Grid Control Center that, “There will be personnel at work on the _ line or _ line section.” This statement is to be recorded in red on the logs at all stations concerned other than the switching center. The same notification and

log entry is to be made at a station that has supervisory control of one of the terminal stations, but is not itself a terminal station.

4.3 After all clearances have been released, the above stations will log in blue the notification received from the switching center or Grid Control Center that, “All personnel are clear of the _ line or _ line section.”

4.4 At an unattended substation, it is not necessary to carry forward clearances or personnel at work on lines or equipment.

4.5 A System Operator assuming shift will sign all outstanding clearances.

5.0 Margin Symbols

5.1 All margin symbols listed below will be noted in red. When the condition that called for the margin symbol no longer exists, the margin symbol shall be canceled with a blue line.

Symbol	Indication
NTO	Used to indicate that a "No Test Order” has been issued (Refer to SOB #314.)
HLO	Used to indicate a "Hot Line Order" has been issued (Refer to SOB #3.)
SG	Used to indicate that a line or piece of equipment has been de-energized on a "Safeguard" basis (Refer to SOB 6.)
SO	Used when a "Special Order" has been issued to cover unusual or abnormal conditions not covered by the above symbols
CT	Used when a current transformer has been shorted by the use of a roto switch or other means
R	Used when a protective relay has been made solid (nonautomatic)
	Used when ground disconnects are closed
	Reserved for any unusual conditions not covered by the above and which should be specifically drawn to the attention of the system operator or acting operator

5.2 In the event that a margin symbol is outstanding at the end of the day, the margin symbol shall be carried forward with the entry to the following day log or to the abnormal system status at the attended switching center.

6.0 Abbreviations

Abbreviations will be limited to those standard abbreviations common in Substations. Symbols used in the body of an entry are limited to “#” for number and “Ø” for phase.

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G6: Routine and Emergency Communications

1.0 General

1.1 All routine switching, maintenance, testing, and other work that might influence the operation of the system will be done on orders from the switching center system operator or an agency having jurisdiction. Refer to APM, Rule 704.

1.2 All personnel shall make their work location known to the switching center with jurisdictional control in the area they are working and remain in contact with them during their work. This will allow them to be contacted, if necessary.

1.3 If the crew is equipped with a Company radio, the person in charge shall ensure the unit is in proper operating order. If the radio is not functioning, other means of contact will be established.

1.4 In an effort to establish formal communication to improve quality and performance, voice recorders have been installed on all System Operator phones at all Switching Centers. A rhythmic beep will be heard on the telephone whenever a conversation is being recorded. These recordings will be stored and retrieved as business needs dictate. As a reminder, it is important to maintain effective and formal communication between field personnel and the System Operators. Please continue to follow all established policies regarding business communications.

2.0 Entering Unattended Substations

2.1 Unattended substations may be equipped with entry alarms, at local supervision's discretion. If so equipped, the person entering the unattended substation must, prior to entry or within two minutes after entry, call the switching center operator. If an alarm is received and the switching center operator is unable to determine who has entered the substation he/she must dispatch the necessary agency to investigate.

3.0 Reporting Progress of Work

3.1 Notify the switching center operator a minimum of 30 minutes before clearing off a line or piece of equipment. This is to allow time to schedule operators for switching if necessary.

3.2 Notify the switching center operator as soon as you become aware of a line or piece of equipment that will not be returned to service as programmed. If the outage will be extended another day, other programs may have to be canceled.

3.3 The Grid Control Center must be immediately informed of any adverse conditions that might influence the operation of the system. All employees shall report conditions such as lighting, wind, rain, snow, ice, or other conditions observed that are deemed important to the switching center operator.

3.4 Do not delay reporting and give as much information as possible. Additional facts should be reported as they become known.

4.0 Details Requested in Reporting Emergencies

4.1 Nature of the emergency (fire, accident, injuries, and so forth)

4.2 Location of the emergency

4.3 Company lines and equipment involved, or possibly involved

4.4 Estimated time before lines or equipment will be involved

4.5 Weather conditions (wind, flooding, and so forth)

4.6 Local agencies on the scene

4.7 Name and classification of person making report

4.8 If and when a later report will be made

4.9 Available means of communication

4.10 In the event any information regarding such a hazard or damage is received from an outside source, all available facts should be requested. The person reporting and how they may be contacted should be included if possible. All such reports should be reported to the switching center operator or to the Grid Control Center.

4.11 In all cases, the intent is to provide information that will assist in avoiding or reducing the damage to lines and equipment, and avoiding interruption of service.

5.0 References

- The *Accident Prevention Manual*, Rule 704
- SOB 12, Report to the Grid Control Center

G7: Notification of Interruptions and Hazards

1.0 General

Each Substation employee shall report any line outage, damage, or hazard to Company personnel or property immediately to the Supervisor or the Switching Center having jurisdiction. If the employee is doubtful about whether or not to make a report on an incident, he/she should make the report and let the Supervisor determine further action.

The Switching Center Operator will report all outages on the distribution system to the Distribution Operations Center. All transmission lines and substation outages will be reported to the appropriate Manager or an appointed representative having jurisdiction and to the Grid Control Center.

The Distribution Operations Center must be informed of any condition in the area that may cause public comment of either a major or minor nature. Once the responsible supervisor has been notified, he/she will notify all other necessary personnel.

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G8: Security

1.0 General

Because of increased public exposure, SCE facilities and equipment must be maintained in a manner that presents the least hazard to the public. Every effort must be made to prevent unauthorized entry into our substations, equipment yards, or buildings to prevent injury, vandalism, or theft.

2.0 Substations

2.1 The substation switchyards with their energized high-voltage lines and equipment are a potential hazard to any unqualified person. All material having a resale or junk value should be locked up or hidden to prevent enticing entry into these areas for theft.

2.2 In order to maintain service to the public, vandalism must be eliminated within the substations. To prevent vandalism, the gates, fences, doors, and entry alarms must be in good order. Gates must be locked or controlled as stated in the Accident Prevention Manual, Section 40.15.10, Rule 103.

2.3 A routine facility inspection of all station equipment, including but not limited to: buildings, foundations/supports, fences, trenches/covers, tanks, above- ground piping and valves should be performed as specified in our CISO Filed Maintenance Practices or CPUC GO174 practices. Identified discrepancies found during inspections are documented, reviewed and assigned a priority rating. Discrepancies that require immediate action are communicated to responsible personnel.

2.4 When any employee is leaving an unattended substation, s/he shall ensure that all doors and gates are locked and the entry alarm, where equipped, is automatic.

3.0 Vehicles and Equipment

To prevent vandalism or theft to Substation vehicles, equipment, and tools, each manager will establish a security policy as applicable in compliance with the following:

3.1 Vehicles parked in unattended substation yards shall have all bins, ignitions, and cabs locked. The door and ignition keys must be either locked inside a tool bin or deposited on a keyboard inside a locked room.The back, unsecured cargo area, of vehicles such as maintenance trucks must have all tools and materials of value removed and secured. This includes spools of wire, cable, bare copper and personal grounds.

3.2 Vehicles parked inside an attended substation yard will similarly be locked. This will permit the vehicle to be moved if necessary. If desired, the yard lights may be left on for added security as approved by the local Grid Operations Supervisor. The supervisor will take into consideration surrounding enviornment issues, such as a residential neighborhood.

3.3 If equipment (graders, cats, and so forth) is to be left in the field, every effort should be made to park the equipment near a farmhouse, ranch, or service station. All bins, ignitions, and cabs shall be locked and the keys retained by responsible persons. Fire extinguishers and similar equipment should be removed and locked inside the bins. If equipment (wire stringing, and so forth) is to be left in the field over a weekend, or in a known trouble area, it should be parked in the most secure location available. If the security of the equipment is still in doubt, guards should be employed.

3.4 All keys should be left in a location where more than one person has access to them.

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G9: Security Inspections

1.0 Purpose

The purposed of this directive is to reaffirm the SCE's existing policies and practices and to outline procedural guidelines for conducting inspections at Substation facilities. In order to maintain discipline, promote the safety and welfare of employees and members of the public, and to protect SCE's property, these rules must govern employee conduct while on company premises.

2.0 General

2.1 Policy

All Substation facilities are semi-restricted areas. Admission to these facilities is governed by SOM G8: Security.

2.2 Authority

The manager or designated representative has the authority to determine the inspection party members, as well as the frequency and selection procedure by which random inspections will be conducted, in accordance with this SOM policy.

2.3 Responsibility

It is the responsibility of each manager to develop an administrative procedure to assure specific location compliance with this order. Random inspections are deterrent in nature and should be administered accordingly.

2.4 Notice

In connection with the inspections herein defined, the following notices will be posted at the entrance to all SCE facilities:

A. Searches by authorized SCE representatives may be made of any locker, storage area, vehicle, person, or personal effects on this property at any time without prior announcement.

B. Pyrotechnics, explosives, firearms or other weapons, alcohol, and drugs are prohibited on SCE property.

3.0 Inspections Upon Entering and Leaving Company Property

All persons will, from time to time and in instances where reasonable suspicion exists, be subject to inspection when entering and leaving SCE property. All portable containers, whether hand-carried or in vehicles, including lunch boxes, tool boxes, purses, and so forth, are subject to inspection.

4.0 Company-Provided Locked Storage Space

4.1 Company employees are provided storage space for clothing, personal effects, tools and, in some cases, certain SCE property authorized for individual use. Employees requesting use of SCE-owned locked storage space will be assigned an appropriate space and lock. Each storage space will be registered and issued exclusively to the requesting employee in accordance with the Locked Storage and Lock Assignment Form and, where applicable, one tool space.

4.2 Use of personal locks or other locking devices of any type on SCE-owned storage space is prohibited and will be removed. Upon request and signed receipt, master-keyed combination locks will be issued by serial number for each assigned SCE storage space as referenced above. Each facility will have a separate master key for the purpose of inspection.

4.3 SCE-provided locked storage spaces are subject to random inspections as authorized by the field location manager or designated representative. With practicality in mind, storage areas should be centrally located to simplify the logistics of inspection. The inspection team should normally be comprised of two supervisors and, where a represented employee is involved, a union representative.

4.4 Desks are not to be used for securing personal items of employees. They are provided for the organization and storage of SCE property and for employee work space. Desks are to remain unlocked unless authorized by the field location manager or designated representative and are subject to inspection as outlined above.

5.0 Non-Company Provided Locked Storage Space

All employee-provided storage spaces must be registered and may be subject to random inspection as outlined above.

6.0 Inspections When Reasonable Suspicion Exists

An inspection of an employee (or the employee's personal effects) may be made where reasonable suspicion exists to believe that the employee is, at the time of the inspection, in possession of stolen property or prohibited items. Reasonable suspicion exists when, on balance, in light of all of the facts known, there is more reason to think the employee possesses the item than not.

7.0 Random Vehicle and Pedestrian Inspection — Supervisor Procedures

The following guidelines should be followed by Substation supervisors during random inspections of vehicles and pedestrians entering and leaving SCE facilities.

7.1 Refusal to Consent to Inspection

A. If the employee refuses to consent to the inspection, he/she is to be advised by the supervisor that he/she is being directed to comply and that refusal to consent to the inspection will be deemed insubordination which may result in disciplinary action, including termination.

B. Investigation/Presence of a Union Representative

7.2 If supervision has reason to believe the employee has been insubordinate, the discussion becomes investigatory in nature and the employee is entitled to a union representative if he/she so requests one.

7.3 If the employee requests a union representative, one should be provided whenever possible. If no union representative is available, the employee may participate in the investigatory interview without the presence of a union representative or be relieved from duty and told to report back when a union representative is available.

7.4 When an investigation proceeds to the point where the supervisor believes that disciplinary action will be taken, the employee should be informed of his/her right to a union representative

under the contract. If no union representative is available, the employee should be relieved from duty and told to report back for a disciplinary meeting when a union representative is available.

7.5 Presence of Prohibited Items.

A. When an inspection reveals a prohibited item, supervision will confiscate it.

B. Investigation Presence of a Union Representative

1. Because prohibited items range from fireworks to drugs or alcohol, supervision's response to each incident must be on a case-by-case basis.

2. If supervision has reason to believe the employee is in violation of a SCE policy or rule, the discussion becomes investigatory in nature and the employee is entitled to a union representative if he/she so requests one.

3. If the employee requests a union representative, one should be provided whenever possible. If no union representative is available, the employee may participate in the investigatory interview without the presence of a union representative or be relieved from duty and told to report back when a union representative is available.

4. When an investigation proceeds to the point where the supervisor believes that disciplinary action will be taken, the employee should be informed of his/her right to a union representative under the contract. Where the facts so warrant, the employee may be placed on investigatory suspension. If no union representative is available, the employee should be relieved from shift and told to report back for a disciplinary meeting when a union representative is available.

7.6 Documentation and Notification

All incidents should be promptly and thoroughly documented and reported to the appropriate level of management, Labor Relations and, where applicable, the Law Department, Health Care Department, and Corporate Security.

8.0 Locked Storage Inspection Procedures

The following guidelines should be followed by Substation supervisors in conducting inspections of SCE-provided locked storage on SCE facilities.

8.1 Random inspections of lockers, tool boxes, desks, or other containers or storage areas which are supplied by SCE for work-related use may be conducted at any time as authorized by the field location manager or designated representative.

8.2 The inspection should be composed of two supervisors and, where inspections involve bargaining unit employees, a union representative. Identify the specific spaces to be inspected in accordance with random selection procedures for your location.

8.3 Obtain the appropriate master key for combination locks. Secure all areas to be inspected to prevent access by unauthorized personnel.

8.4 The employee need not be present during inspection if SCE-provided locked storage spaces, but should be present during inspection of non-SCE provided storage. Any personal effects

such as wallets, purses, or lunch pails found within such containers or storage areas should not be searched without the employee's permission. Inspect the contents of each locked storage space for prohibited items. When possible, contents should be left in the condition they were found in.

A. Presence of Prohibited Items

1. When an inspection reveals a prohibited item, it should be confiscated, placed in a clear plastic bag, and sealed by evidence tape. Both supervisors and the union representative should date and sign across the evidence tape.

2. The plastic bag should then immediately be placed in a security bag for storage and transported for later use as evidence.

B. Investigation/Presence of a Union Representative

1. Because prohibited items range from fireworks to drugs or alcohol, supervision's response to each incident must be on a case-by-case basis.

2. As soon as the employee can be summoned to discuss the prohibited items found, a meeting should be arranged. If supervision has reason to believe the employee is in violation of an SCE policy or rule, the discussion becomes investigatory in nature and he/she is entitled to a union representative if he/she requests one.

3. If the employee requests a union representative, one should be provided whenever possible. If no union representative is available, the employee may participate in the investigatory interview without the presence of a union representative or be relieved from duty and told to report back when a union representative is available.

4. When an investigation proceeds to the point where the supervisor believes that disciplinary action will be taken, the employee should be informed of his/her right to a union representative under the contract. Where the facts so warrant, after the union representative arrives, the employee may be placed on investigatory suspension. If no union representative is available, the employee should be relieved from shift and told to report for a disciplinary meeting when a union representative is available.

C. Documentation and Notification

All incidents should be promptly and thoroughly documented and reported to the appropriate level of management, Labor Relations, and where applicable, the Law Department, Health Care Department, and Corporate Security.

9.0 Employee Inspection Procedure

9.1 An inspection of an employee (or the employee's personal effects) may be made where reasonable suspicion exists to believe that the employee is, at the time of the inspection, in possession of stolen property or prohibited items.

9.2 Reasonable suspicion exists when, on balance, in light of all the facts known, there is more reason to think the employee possesses the item than there is reason to think he/she does not. Reasonable suspicion does not mean that there is no doubt about the employee's guilt, but it means more than just a suspicion of misconduct.

9.3 There is no one type of evidence that will satisfy the requirement of reasonable suspicion. Obviously, the best evidence is personally observing the employee taking SCE property or being in possession of contraband. There are, however, other ways supervision can have reasonable suspicion. Another worker (who is believed to be reliable) may tell you he/she saw the employee taking SCE property. The employee in question may also have the strong odor or alcohol on his/her breath or marijuana on his/her person. Or you may observe a pattern of items that belong to SCE disappearing after the employee has used them.

9.4 Each situation is different, and supervisors should always exercise good judgment and common sense. If a supervisor is unsure, his/her suspicions should be discussed with Substation management, other supervisors, or Labor Relations before acting.

9.5 Permissible Employee Inspections

A. Where supervision has reasonable suspicion to believe that an employee possesses stolen goods or prohibited items, inspection of the employee and/or his/her personal effects should be conducted in accordance with the following guidelines. Supervision may retrieve stolen property or prohibited items from an employee if in plain view. Plain view simply means that the article can be seen without opening a pocket, lunch pail, tool box, or purse.

B. If the stolen property or prohibited items are not in plain view, supervision may conduct an inspection of the employee and/or his/her immediate personal effects (such as a purse, lunch pail, a personally owned tool box, or automobile) if the employee gives permission. The employee should be asked for permission to conduct such an inspection.

C. It is extremely important that these authorized searches be conducted in a reasonable manner.

D. Supervision should:

- Obtain a witness — the inspection should be conducted in the presence of two supervisors whenever possible
- Attempt to provide a union representative if requested, whenever possible — if no union representative is available, the employee should be told that a union representative is not available
- Avoid touching the employee's body
- Search only those areas in which there is reason to believe that the article in question is located
- Conduct the search in a place which will minimize embarrassment to the employee — inspections should be conducted by a person of the same gender as the employee whenever possible.

E. Investigation/Presence of a Union Representative

1. Where the inspection reveals what supervision believes to be stolen property or prohibited items, the discussion with the employee becomes investigatory in nature and the employee is entitled to a union representative if he/she so requests one. If the employee requests a union representative, one should be provided whenever possible. If no union representative is available, the employee may participate in the investigatory interview without the presence of a union representative or be relieved from duty and told to report back when a union representative is available.

2. When an investigation proceeds to the point where the supervisor believes that disciplinary action will be taken, the employee should be informed of his/her right to a union representative under the contract. If no union representative is available, the employee should be relieved from shift and told to report back for a disciplinary meeting when a union representative is available.

9.6 Refusal to Consent to Inspection

A. If an employee declines supervision's request to conduct a reasonable inspection of his/her person or personal effects, the employee should be informed that failure to cooperate may result in disciplinary action, including termination.

B. If the employee continues to refuse, he/she is to be advised that the supervisor is directing him/ her to consent to the inspection and that refusal to do so will be deemed insubordination which may result in disciplinary action, including termination.

C. Investigation/Presence of a Union Representative

1. If supervision has reason to believe the employee has been insubordinate, the discussion becomes investigatory in nature and the employee is entitled to a union representative if he/she so requests one. If the employee requests a union representative, one should be provided whenever possible. If no union representative is available, the employee may participate in the investigatory interview without the presence of a union representative or be relieved from duty and told to report back when a union representative is available.

2. When an investigation proceeds to the point where the supervisor believes that disciplinary action will be taken, the employee should be informed of his/her right to a union representative under the contract. Where the facts so warrant, after the union representative arrives, the employee may be placed on investigatory suspension. If no union representative is available, the employee should be relieved from shift and told to report back for a disciplinary meeting when a union representative is available.

9.7 Documentation and Notification

All incidents should be promptly and thoroughly documented and reported to the appropriate level of management, Labor Relations and, where applicable, the Law Department, Health Care Department, and Corporate Security.

G10: Commercial Vehicle Operation Logging and File Maintenance Procedures

1.0 Overview

The following procedures are established for Substation Construction and Maintenance (SC&M) employees who are required to hold a Commercial Driver License (CDL) within SC&M. This policy is intended to cover those employees who on a routine or occasional basis may have the need to operate a commercial vehicle in the performance of their duties.

2.0 Logging Requirements

2.1 Construction Field Forces

If an employee does not drive a commercial vehicle in any given month then no action is required.

Employees who are required to maintain a CDL for employment shall complete and have in their possession an SCE driver's daily log (SCE 37-273-A) each day they operate a commercial vehicle. In situations where operation of a commercial vehicle is occasional, for example, more than 8 days lapse between driving duties, a log book entry stating "has not operated a commercial vehicle in the past 8 days, time sheets on file in office" shall be entered in the remarks area of the previous day that driving will be done. If driving is more regular than every 8 days, the log book is used as a monthly log.

- The white copy of the SCE driver's daily log (SCE 37-273-A) that is filled in shall be turned in at least every 13 days to the employee's foreman for filing. The foreman shall deliver the copies to the Supervisor 3 (S3) once a month. The responsible S3 must keep the filled in white copies of the SCE driver's daily log for each employee on file for six months in the DMV log filing cabinet located in Alhambra.
- Each employee will keep and maintain their SCE driver's log (SCE 37-273-A) until all pages have been used. It can be discarded 15 days after it no longer has any empty pages and all used white sheets have been filed.
- SC&M supervisors shall ensure all crew members have completed an SCE driver's daily log (SCE 37-273-A) and check the logs for completion.

2.2 Substation Maintenance Employees

If an employee does not drive a commercial vehicle in any given month then no action is required.

Employees who are required to maintain a CDL for employment shall complete and have in their possession an SCE driver's daily log (SCE 37-273-A) each day they operate a commercial vehicle. In situations where operation of a commercial vehicle is occasional, for example, more than 8 days lapse between driving duties, a log book entry stating "has not operated a commercial vehicle in the past 8 days, time sheets on file in office" shall be entered in the remarks area of the previous day that driving will be done. If driving is more regular than every 8 days, the log book is used as a monthly log.

- The white copy of the SCE driver's daily log (SCE 37-273-A) that is filled in shall be turned in at least every 13 days to the employee's foreman or immediate supervisor for filing. The foreman or supervisor shall deliver the copies to the S3 once a month. The responsible S3 must keep the filled in white copies of the SCE driver's daily log for each employee on file for six months in the DMV log filing cabinet located at their respective base.

- Each employee will keep and maintain their SCE driver's log (SCE 37-273-A) until all pages have been used. It can be discarded 15 days after it no longer has any empty pages and all used white sheets have been filed.
- SC&M supervisors shall ensure all crew members have completed an SCE driver's daily log (SCE 37-273-A) and check the logs for completion.
- For Nevada based crew members, a log book is required on vehicles over 10,001 lb gross vehicle weight rating (GVWR). This policy will change the third quarter of 2005.

2.3 Apparatus Test

If an employee does not drive a commercial vehicle in any given month, then no action is required.

Employees who are required to maintain a CDL for employment shall complete and have in their possession an SCE driver's daily log (SCE 37-273-A) each day they operate a commercial vehicle. In situations where operation of a commercial vehicle is occasional, for example, more than 8 days lapse between driving duties, a log book entry stating "has not operated a commercial vehicle in the past 8 days, time sheets on file at work base" shall be entered in the remarks area of the previous day that driving will be done. If driving is more regular than every 8 days, the log book is used as a monthly log.

- The white copy of the SCE driver's daily log (SCE 37-273-A) shall be turned in at least every 13 days to the employee's foreman or immediate supervisor for filing. The foreman or supervisor will review the log sheets for completeness and accuracy and give them to the Operation Support Clerk at the work base.
- Each employee will keep and maintain their SCE driver's log (SCE 37-273-A) until all pages have been used. It can be discarded 15 days after it no longer has any empty pages and all used white sheets have been filed.
- SC&M supervisors shall ensure all crew members have completed an SCE driver's daily log (SCE37-273-A) and check the logs for completion.
- The Operation Support Clerk shall file the SCE driver's daily log (SCE 37-273-A) in the appropriate driver's file and maintain six months within the file maintained at the work base.

Note(s):

When traveling across state lines, the vehicle weight limitation for commercial vehicles drops to 15,000 lb GWVR.

3.0 Drivers Qualification File

Each work location shall maintain a drivers qualification file (DQF) on employees who are required or may be required to operate commercial vehicles in the course of their daily business. The file shall maintain the following documents:

- Copy of a valid Commercial Drivers License (CDL)
- Copy of a valid Medical Examiner's Certificate DL 51A (CDL Medical Card)
- Drivers Capabilities Form SCE 268 A

All SC&M employees who are required to maintain a CDL for employment shall provide a copy of the following documents to their supervisor for filing:

- Copy of a valid Commercial Drivers License (CDL)

- Copy of a valid Medical Examiner's Certificate DL 51A (CDL Medical Card)

Construction Field Forces employee DQFs are located in the Construction Maintenance Accounting (CMA) office in Alhambra.

Maintenance employee DQFs are located in each crew's foreman office at their work base.

Apparatus Test DQFs are available through the OPS support clerk, located at the employee's work base.

4.0 Truck Notebooks

The truck notebook shall become the responsibility of the foremen assigned to that vehicle.

It is the responsibility of the employees using a commercial vehicle borrowed from another crew to ensure the appropriate information is maintained and complied as required.

4.1 Daily Vehicle Inspection is conducted and the SCE 39-34 is completed and filed in the truck notebook.

4.2 The operator fills out his daily log.

4.3 The boom inspection is completed prior to the first use of the day and the boom card is signed (add boom card number) and that the boom card is marked "Not In Use" on the days the boom is not used.

4.4 All applicable permits are up to date.

4.5 File California Highway Patrol (CHP) correspondence as it is received.

4.6 Maintain the work location section as per local management.

Attachments:

1. Completed Daily Log (non-operational) SCE37-273-A
2. Completed Daily Log (non-operational) SCE37-273-A
3. Copy of medical certification DL-51A (CDL Medical card)
4. Drivers capability SCE 268-A

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G11: Confined Space Policy

1.0 General

TDBU Substation and contract personnel who may be required to enter into a confined space, or other confined space inside substations must follow all relevant TDBU policies and procedures, which are located on the TDBU Safety & Environmental Portal, under the heading of Confined and Other Confined Space.

At this time TDBU employees are not allowed to enter a Permit Required Confined Space. TDBU confined space policies and procedures govern how employees may reclassify a permit required confined space to a non-permit confined space, which would allow entry.

2.0 Access to TDBU Confined and Other Confined Space Policy

Please refer to the TDBU Confined and Other Confined Space Policy, located on the TDBU Safety & Environmental Website:

Confined Space Safety

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G12: APM Rule 409 Clarification

1.0 General

1.1 This policy is intended to clarify APM, Rule 409, which addresses working on energized disconnect switches.

1.2 The SC&M organization identified a need to clarify APM, Rule 409 in order to perform work safely and effectively.

2.0 APM, Rule 409 Clarification

2.1 Removing a lead from a disconnect while the opposite end is energized is hazardous work and may only be done at the discretion of the supervisor in charge of the job, per APM, Rule 409.

2.2 The preferred method of dealing with this situation is to schedule an outage that de-energizes both sides of the disconnect. It is not acceptable to work on a disconnect while the opposite end is energized due to poor outage planning. All outage options shall be exhausted before permission is given to proceed with removing a lead from the de-energized side of a disconnect while the opposite side is still energized.

2.3 Removing a de-energized lead from a disconnect while the opposite end is energized may be done with supervisory approval, as long as all safety rules are followed.

2.4 All applicable safety rules and procedures shall be used to ensure personnel safety, such as:

A. Safe approach distances

B. Use of Tupperware

C. Use of a checker

D. Proper grounding techniques

E. Use of a proper and effective Tailboard

F. Job supervisor approval

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G13: Substation Clothing Policy

1.0 General

1.1 This policy is intended to clarify expectations from Substation Management for proper PPE when entering a normally energized substation switch rack. This policy is intended to be in addition to existing APM rules.

2.0 Policy

2.1 When anyone enters a normally energized substation switch rack the following SCE approved PPE shall be worn: hard hat, an AR/FR shirt (8 calorie minimum) tucked in with sleeves rolled down, buttoned, and collar buttoned to the next to the last button, AR/FR pants (8 calorie minimum), eye protection, and foot wear.

NOTE

AR/FR shirt and AR/FR pants can be substituted with company provided AR/FR coveralls, (8 calorie minimum) buttoned/zipped with sleeves rolled down, buttoned.

2.2 When anyone is actively engaged in performing, or observing, work that could put the employee(s) in proximity of the arc flash hazard, by reason of the work being performed, the employee(s) must wear location specific calorie rated AR/FR PPE.

NOTE

Many substation locations in the SCE territory will require greater than 8 calorie PPE. See Substation Arc Flash Manual for substation specific calorie protection requirements. The Manual includes both AC and DC locations.

The following activities are examples of arc flash hazards:

- Primary Switching
- Grounding
- Testing of Primary Voltages
- Racking CB in or out of the operating position
- Work that requires an electrical checker (APM Rule 408) or, if working alone, would have a checker if one was available
- Opening and/or working in 480 Vac panels (exception: diagnostics at 480V panels is not arc flash hazardous).
- Opening and/or working in DC panels – 120 Vdc and above; 350 AH and above (when the energized bus is able to be covered by an insulating blanket, this task is not arc flash hazardous).
- Working on main battery terminals — 120 Vac, and above; 1000 AH and above

2.3 Approved foot wear shall be defined as: A work boot or shoe constructed of leather and a hard sole shoe. No athletic or tennis shoes.

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G14: Substation Cybersecurity Standard

1.0 General

1.1 This standard establishes the security principles and practices required to ensure the safety, reliability, confidentiality, integrity, and availability of Southern California Edison's (Company) Substation Control System or Device(s) (SCSD) owned, operated, or leased by the Company, including protected data stored on these Substation Cyber Assets.

1.2 All Substation Control System or Device(s) must be designed, developed, implemented, managed, operated, and supported to:

- Minimize security risks,
- Ensure their availability, confidentiality, and integrity at all times,
- Comply with the Company's Physical Security and Cybersecurity Policy.

2.0 Applicability

2.1 The substation Cybersecurity Standard applies to:

- All Company employees responsible for managing, operating, or procuring Substation Control System or Device(s).
- All Substation Control System or Device(s) owned and operated by the Company.

2.2 If you are a Company employee who is responsible for Supplemental Workers, you must provide this standard to any Supplemental Worker that supports the design, development, management, operations, or procurement of Substation Control System or Device(s).

2.3 All technology (new or existing Computing Systems) in the design initiation phase of the project life cycle must be designed, developed, built and implemented to comply with the standard revision that is approved during the design initiation (authorization to proceed/ATP) phase of the work. Any opportunity to comply with future revisions of the Substation Cybersecurity Standard without impacting the design or operation of the OT assets must be subject to a Cybersecurity risk assessment prior to baseline changes.

2.4 Requests for exceptions to this standard must be requested by submitting a Miscellaneous request in Remedy and attaching a completed Cybersecurity Standards Exception Form.

2.5 Substation cyber equipment must meet the minimum criteria outlined in the SCE CIP Programs (SSM, CCM, etc.) for BES stations or the SCE Substation Cybersecurity Standard.

3.0 Access to the Substation Cybersecurity Standard

Please refer to the Substation Cybersecurity Standard, located on the T&D Standards and Publications Portal.

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G15: Substation Vehicle Operating Protocol

1.0 Purpose

Operating vehicles in SCE substations is an essential part of daily operations. Using proper vehicle operating protocol helps ensure a safe environment when inside a substation. This document pertains to all vehicles and mobile equipment (i.e. trucks, forklifts, man lifts, electric and gas OHVs, etc).

2.0 Guidelines

2.1 Prior to Driving

A. A “Circle of Safety” inspection will be performed on any company, rental or personal vehicle prior to it being operated on substation property. The Circle of Safety inspection is defined and detailed in Appendix A.

B. Once inside the vehicle, the following tasks shall be performed before the vehicle is driven:

1. Plan route and set up any electronic navigation device beforehand.
2. Stow and secure all loose items inside the cab including all electronic devices.
3. Ensure mirrors are adjusted.
4. Seat belts shall be worn at all times per Accident Prevent Manual (APM) Rule P-123 J.

2.2 Entering/Exiting Substations

A. Be aware of traffic conditions and pedestrians when approaching and exiting the substation.

B. The following applies when approaching a substation gate:

1. Ensure the back of the vehicle does not encroach onto the street whenever possible.
2. At substations with electric gates, verify gate is fully open, and ensure you have enough time to get through the entrance before the gate closes automatically. Beware, gate closing times vary and not all gates have vehicle detectors.
3. At substations with manual gates, open and secure gate properly before entering/exiting.
4. Verify gate latches securely, if not secure gate by other method i.e. (coworker, rope, cones, etc.).
5. All inoperable latches should be reported to the Facility Maintenance Supervisor (FMS).

6. Be aware of work activity being performed and any driving hazards that may be present.

C. When exiting a substation, consider using a spotter to verify that traffic is clear when one is available.

2.3 Driving Inside a Substation

A. All stop signs, traffic arrows and speed limits shall be adhered to at all times. Where speed limits are not posted 15 mph is the maximum speed when safe to do so.

B. Unless necessary, do not drive near obstacles or energized equipment. Use a spotter whenever there is one available. In some instances, an Electrical Checker may be warranted.

C. Be aware of ongoing construction and abnormalities.

D. Whenever possible drive only on designated paths. Do not drive over obstacles to reach desired location (wood and composite cable trenches, curbs, berms etc.).

E. Be aware of any hazardous overhangs like low profile roofs and air conditioners.

F. Driving in reverse:

1. Should only be done when absolutely necessary.

2. Driving in reverse should be done slowly and only for the minimum required distance necessary.

3. Always use a spotter when driving in reverse if one is available.

4. If a spotter is not available do the following.

a. Get Out And Look (GOAL). Walk the path you plan to drive.

b. A good practice is to place a cone at the target location and back no further than the targeted cone with windows down.

2.4 Parking

A. Vehicles will not be parked in a position that requires backing unless all other prudent options have been considered.

B. Once a vehicle is parked, it should only be used for reasonable transportation inside the substation (i.e. Inspections should not be performed from the front seat of a truck/vehicle).

C. The preferred method after parking, for transportation is walking.

D. Parked vehicles shall be put in “Park” and parking brake set. For manual transmissions, vehicles should be left in gear and parking brake set. Vehicles will not be left unattended with the engine running.

2.5 Mobile Equipment

A. The Equipment Operator shall be trained, qualified and familiar with operation of mobile equipment and manufacture/owner's manual prior to operation.

B. Ensure that mobile equipment is in safe operating condition before operating.

C. All applicable rules/policies and appropriate PPE/fall protection shall be worn per company policies.

D. Seat belts when equipped must be worn at all times.

E. APM rule P-11 B (No Horseplay) is to be observed at all times.

F. When man lifts are relocated without a checker between work locations, boom must be fully lowered.

G. All boom type vehicle must have the boom secured when relocating.

H. When operating forklifts, all loads will be secured and kept close to the ground.

I. For Off-Highway Vehicle operation inside substation, refer to the Off-Highway Vehicle Corporate Standard.

Proper grounding protocol must be followed where applicable per the grounding manual.

Appendix 1: The Circle of Safety

The ultimate purpose for walking the Circle of Safety is to verify the vehicle is road worthy and the pathway is clear. If a bin door was opened, did it get closed and latched? If a ladder was removed and put back, did it get strapped and tied down?

If anything was removed from, or added to the truck, the road worthiness of the vehicle could now be compromised. Verifying a vehicle is roadworthy, is the direct responsibility of the driver and the only way a driver can ensure the vehicle is ready for travel is to walk around the vehicle and check it.

GET OUT AND LOOK – G.O.A.L.

You find yourself sitting in the driver's seat getting ready to travel. It then dawns on you that you haven't performed a proper Circle of Safety or confirmed your pathway clear. You should:

"Get Out and Look" aka –

G.O.A.L

There is more to walking the Circle of Safety than just a quick trip around the vehicle looking for something obvious. A proper Circle of Safety includes dedicated attention to the inspection at hand. Each and every bin door should be addressed by putting your hand on it and verifying it is closed, latched and locked. This focuses your attention to each and every door.

Checking the bin doors

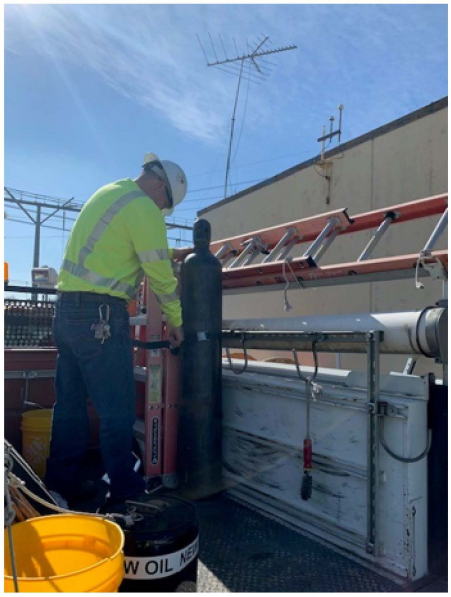
To properly check that the ladders are secure, it usually requires the inspection to be done from the bed of the truck; this also allows for a good visual inspection of the straps or ropes. Each ladder should be checked that it is strapped and secure by pushing and pulling on each and every one.

Ensure each ladder is properly secured

The hot stick holder cap should be physically pulled on to confirm the holder lid is closed and secured. If there is a pin or a latch, it must be verified that it is properly in place. More than one hot stick has been lost because the cap lid to the holder was not closed and secured.

Check hot stick holder lid closed and latched

All cargo in the bed of the truck should be secured and checked that nothing can shift or fly out. High turbulence has caused rags, trash, hard hats, buckets, and aluminum plates to fly out of truck beds while on the freeway; make sure these items are properly stowed. All gas cylinders should be physically checked that their caps are threaded on tightly and the cylinders are secured in the upright position.



Check cylinder bottles are secured

Flat surfaces offer an inviting place for someone to place hardware or a small hand tool(s). Look for loose tools and hardware on the top of the truck tool boxes and bumpers. A tool falling off of a truck tool bin traveling at 65 miles per hour can go through a windshield and hurt a driver or cause a serious accident.

Tool found on top of truck tool box

Make sure the tires look properly inflated before every trip. Verify the running lights and turning indicators work at least every morning. Before each trip, make sure your path is clear before proceeding.

Check tires along with ensuring a clear pathway

The driver performing the Circle of Safety is the last line of defense before a vehicle is put on the road. It doesn't matter what was untied or who untied it. It doesn't matter what was removed or who removed it. It doesn't matter what was put on the truck or who put it there - what does matter, is that the driver performs a proper “Circle of Safety” inspection before driving the vehicle.

If every driver takes three to five minutes to verify the road worthiness of their vehicle, they can save hours of heartache, accidents, and possibly lives.

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G16: Fall Protection - General Guidance Procedures

1.0 General

The purpose of this procedural guideline is to provide employees involved in fall protection activities with general guidance when fall protection is required and list a few examples to maintain compliance. In all instance's employees will only be allowed to tie off to an approved anchor point.

2.0 Tailboard

Conduct a tailboard to walk/discuss scope, hazards, and rescue.

3.0 Hierarchy of Fall Protection

1. Eliminate the hazard
2. Install passive systems (guardrails/netting)
3. Fall Restraint
4. Fall Arrest

4.0 Fall Restraint vs Fall Arrest

4.1 Fall Restraint

Fall Restraint will not allow worker to extend beyond the edge, zero free fall.

4.2 Fall Arrest

Fall Arrest reduces workers impact force and prevents the worker from hitting lower level.

5.0 Safety Retractable Lanyard & Safety Retractable Device Classes

- Class A: Maximum arrest distance not to exceed 24" (2 ft). Average arresting force not to exceed 1350lbs (6kN) or maximum peak of 1800lbs (8kN).
- Class B: Maximum arrest distance not to exceed 54" (4-1/2 ft). Average arresting force not to exceed 900 lbs (4kN) or a maximum peak of 1800lbs (8kN).

Safety Retractable Lanyard (SRL)

Safety Retractable Device (SRD)

6.0 Leading Edge vs Non-Leading Edge SRLS

If foot level tie off is required, employees shall use their allocated DBI Edge SRL or SRD. These are easily identifiable by their orange pack casing.

7.0 Calculating Fall Clearance

Anchors: Use of an overhead anchor is optimal as this reduces the arrest distance and force. However, every location is different, and you may have to tie off to foot level.

Example 1: Foot level tie off using a Class B SRL/SRD & height of a 6 ft worker

- Height of worker free fall: 6 ft
- Class B SRL/SRD max arrest distance: 4-1/2 ft
- Harness stretch/D-ring shift: 2 ft
- Safety Factor: 2 ft

Needed height below you in this example: 14-1/2 ft

Example 2: Overhead anchor tie off using a Class B SRL/SRD & height of a 6 ft worker

- Class B SRL/SRD max arrest distance: 4-1/2 ft
- Harness stretch/d ring shift: 2 ft
- Safety Factor: 2 ft

Needed height below you in this example: 8-1/2 ft

NOTE Swing falls will add to required clearance. As you swing below anchor point, you get closer to the level below.

If you do not have the needed fall clearance to perform your task and or tethering may create a higher risk and all other options have been exhausted, please consult Safety, Construction Methods group and the line senior manager for assistance/approval.

8.0 Harness Inspection & Fitment

8.1 Inspection

(*See Appendix 1 below*):

To be done every time before use and inspected by the Competent Person every (6) months.

Performing an inspection shall consists of the following:

- Pick up the harness by its D-ring in the back
- Gently shake the harness to let the straps fall into place
- Check all category elements as noted below

A. Hardware: Buckles, D-rings and Keepers.

Must not be damaged, broken, distorted, free from sharp edges, burrs, cracks worn parts, corrosion.

B. Webbing: Cuts, frays, broken fibers, tears, abrasion can be no greater than 1/8-inch holes or burns can be no greater than 1/16-inch diameter. Look for discoloration and hard spots or mold.

C. Stitching: Look for broken stitches, there should not be more than 2 per stitch pattern.

D. Labels: Should be present, legible / clean, Indicate: date of manufacture, serial no. / model no., standards, size, care, warnings, and inspection log.

8.2 Applying Harness & Checking Fitment

(*See* Appendix 2 *below*):

A. Lift the harness over your shoulders like a vest (Figure 1)

B. Make sure the D-ring is in the middle of your back, directly between your shoulder blades.
(Figure 2)

C. Pull each leg strap up and fasten the buckles together. (Figure 3)

D. Stand up straight and adjust the length of the side body straps as needed to make sure there is no slack. (Figure 4)

E. Connect the chest strap about mid-chest high. (Figure 5)

F. Adjust the chest strap as necessary to remove any slack. (Figure 6)

G. Make sure the shoulder straps and leg straps are snug, while still allowing full range of motion.

H. Eliminate any excess slack by tightening the straps in the buckle.

I. Make sure the loose ends of the straps are tucked into the strap retainers.

J. With your hand held flat, you should be able to fit your fingers underneath your leg straps. (Figure 7)

9.0 Guidelines

9.1 Working on top of a Transformer

A. Employees must maintain 100% tie off when working and transitioning to and from the top of a transformer.

B. Install guardrails/barriers if available and practical

- Employee must be tied off while on top of a transformer even if guardrails are installed.

C. If there are no fall arrest poles (davit), horizontal lifelines, or approved anchor points, employee must consult safety and engineering.

- Alternative options such as a mobile fall protection equipment unit shall be requested if an approved anchor point cannot be achieved.

D. Employee's SRL must be attached at a minimum of 4ft above the walking/working surface, if not a leading edge SRL must be used.

E. Employees shall stage aerial basket over platform before stepping off while maintaining 100% tie off in the transition from Point A to Point B.

F. Future units will be manufactured with approved anchorage painted in green for ease of identification.

9.2 Lattice/Steel

A. Employees must use aerial lifts/ladders to get to working position. Employees must maintain 100% tie off when working and transitioning to and from lattice and steel structures.

B. Employees may move horizontally along the structure as long as 100% tie off is maintained.

- Vertical climbing must be approved by the corresponding line manager and safety advisor. 100% tie off must be maintained.

C. Alternative options such as a mobile fall protection equipment unit shall be requested if an approved tie off point cannot be achieved.

9.3 Working on a Circuit Breaker

A. Employees must use aerial lifts, ladders, and scaffolding if practical and possible before considering climbing on top of the equipment.

B. Working on top of the equipment is only permitted from a platform surface such as a mechanism cabinet.

1. Employees must maintain 100% tie off when working and transitioning to and from the top of the equipment.

2. Climbing on and tying off to bushings is prohibited.

C. Alternative options such as a mobile fall protection equipment unit shall be requested if an approved tie off point cannot be achieved.

9.4 Trenching & Digging

A. If hole is larger than 30 inches in diameter and has a depth in excess of 5 feet, fall protection is required.

B. Encroaching within 6 feet of as described above, employee must have fall protection PPE.

9.5 Aerial Manlifts

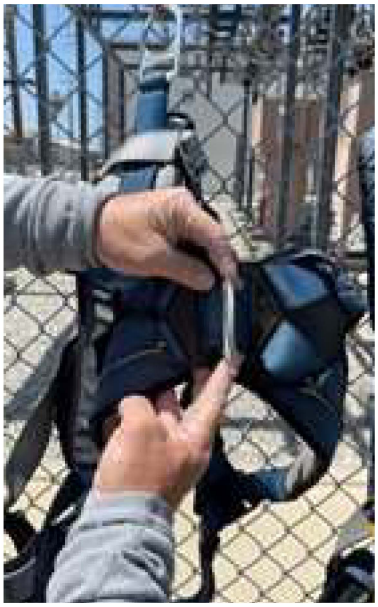
See Accident Prevention Manual (APM) Section 130. General Fall Protection

9.6 Ladders

See Accident Prevention Manual (APM) Section 134. Portable Ladders

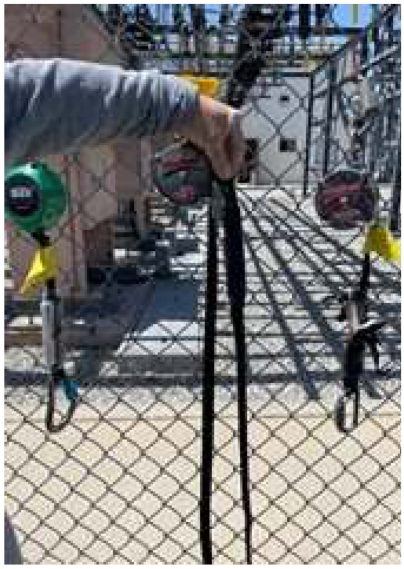
Appendix 1: Examples of Damaged Harness and Safety Retractable Lanyards

Rusted Buckle, D-ring, and Tensioners



Distorted D-ring

Rusted Carabiner: Does not self-close, damaged/torn webbing



Broken Deceleration Pack: Will not retract

Broken stitching

Missing right leg trauma strap

Appendix 2: Applying Harness and Checking Fitment

To apply harness and check its fitment:

STEP 1. Lift the harness over your shoulders like a vest (Figure 1)

STEP 2. Make sure the D-ring is in the middle of your back, directly between your shoulder blades. (Figure 2)

STEP 3. Pull each leg strap up and fasten the buckles together. (Figure 3)

STEP 4. Stand up straight and adjust the length of the side body straps as needed to make sure there is no slack. (Figure 4)

STEP 5. Connect the chest strap about mid-chest high. (Figure 5)

STEP 6. Adjust the chest strap as necessary to remove any slack. (Figure 6)

STEP 7. Make sure the shoulder straps and leg straps are snug, while still allowing full range of motion.

STEP 8. Eliminate any excess slack by tightening the straps in the buckle.

STEP 9. Make sure the loose ends of the straps are tucked into the strap retainers.

STEP 10. With your hand held flat, you should be able to fit your fingers underneath your leg straps. (Figure 7)

Figure 1

Figure 2

Figure 3

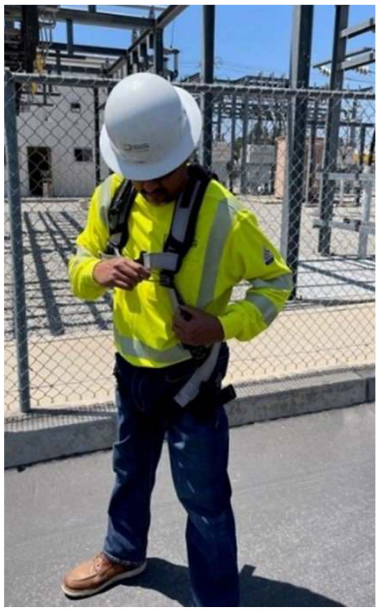


Figure 4

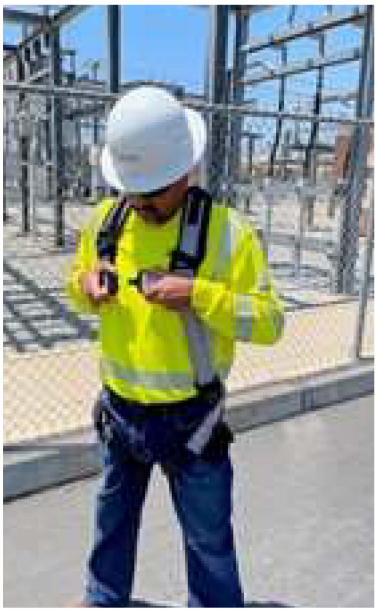


Figure 5

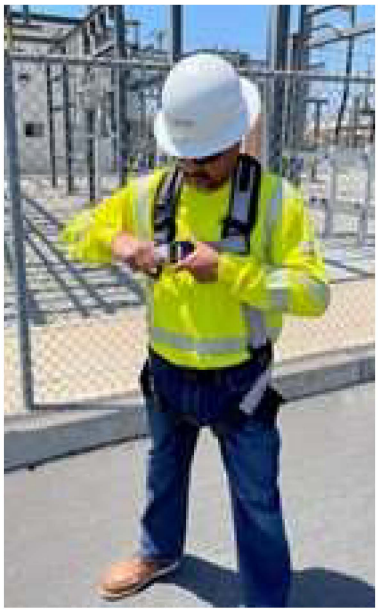


Figure 6

Figure 7

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Section SF: Safety and Fire

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SF1: Injury and Illness Prevention Program

1.0 General

1.1 This program shall, at a minimum, include procedures for training, identifying, and evaluating workplace hazards, including scheduled, periodic inspections to identify unsafe conditions and work practices. Inspections shall be made to identify, evaluate, and correct hazards.

1.2 This procedure was developed to comply with Cal-OSHA California Code of Regulations (CCR) Title 8, Section 3203 for establishing an injury and illness prevention program.

2.0 Training and Instructions

2.1 Training and instruction are necessary for all new programs, employees in new job assignments in which training has not previously been received, or when the supervisor is made aware of a new or previously unrecognized hazard.

2.2 Documentation of safety and health is required for each employee, including employee's name or other identifier, training dates, type(s) of training, and training providers. This documentation shall be retained at the employees work location for three years.

3.0 Periodic Inspections and Documentation

3.1 Scheduled periodic inspections shall identify unsafe conditions and/or work practices. The inspection shall be fully documented and will include action taken, or planned to be taken, to correct the hazard. Required documentation shall be indicated on the appropriate form, and shall be retained at the Switching Center for three years.

3.2 The supervisor or authorized representative, with the authority and responsibility for conducting the inspections, should be identified on the form.

3.3 This program should be used in conjunction with the Accident Prevention Manual which sets the policies and rules of the overall safety program.

3.4 The Inspection Form indicates the required scheduling documentation information.

Periodic Inspection Schedule

Inspection Type	Frequency	Responsibility
Attended Facilities (includes all buildings, structures, and personnel work areas)	Monthly	Operations Supervisor or Designated Representative
Unattended Facilities (includes all buildings, structures, and personnel work areas)	Monthly	Operations Supervisor or Designated Representative
Field Construction (includes line, maintenance, test, patrol, utility, and operating crews)	Annually	Supervisor or Designated Representative
Accounting Staff	Annually	Supervisor or Designated Representative

Note(s):
1. Periodic scheduled inspections are in addition to supervisor visitations.

Figure–1: Substation Inspection Form

Substation Inspection Form

Location _____ Date _____

Inspected By _____

Foreman/Employee Name _____

☐ Safe Conditions and Work Practices Observed

☐ Unsafe Conditions or Work Practices Observed (Corrective Action Required - See Below)

_____

1. _____
2. _____
3. _____
4. _____
5. _____
6. _____

Corrective Action Required Date Corrected

_____

1. _____
2. _____
3. _____
4. _____
5. _____
6. _____

NOTE: Inspection records shall be maintained at the Regional Office for a minimum of three years.

Figure–1: Substation Inspection Form *(Continued)*

Substation
Training/Meeting Record

Date _____ Meeting Location _____ Meeting Time _____ to _____

9 Safety 9 Environmental 9 Other

Presenter _____ Subject*_____ Time _____ to _____

Presenter _____ Subject*_____ Time _____ to _____

Presenter _____ Subject*_____ Time _____ to _____

Participants

	Name (printed)	Signature	Social Security No.
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
12.			
13.			
14.			
15.			

* If additional meeting subject information or outline is available, please attach.

Retain original for your records.

Figure–1: Substation Inspection Form *(Continued)*

Participants (continued)

	Name (printed)	Signature	Social Security No.
16.			
17.			
18.			
19.			
20.			
21.			
22.			
23.			
24.			
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38.			
39.			
40.			

SF2: Injury and Illness Investigation

1.0 General

Substation management has the responsibility to maintain a safe and healthy work environment for its employees. An effective industrial injury and illness program, consistent throughout Substations, will support our goal of injury and illness prevention. This SOM policy outlines the program and shall be followed by all employees.

2.0 Policy and Procedures

Existing Corporate policy, including the *Accident Prevention Manual* (APM), and its rules and practices, and established Substation policies and procedures shall be adhered to at all times.

3.0 Responsibilities

Substation Management has the responsibility for maintaining a safe and healthy work environment for employees and assuring that they perform in a safe manner. Every employee has the personal responsibility to perform their job using safe work habits while adhering to all rules, policies and procedures.

4.0 Investigations

Incidents involving a vehicle accident, injury or illness will be investigated following Corporate guidelines. Investigations shall be held in a timely manner to ensure accuracy in determining the root cause and prevent recurrence. The investigating team shall, at a minimum, include the following members:

4.1 Corporate Investigation Team -

- As designated by the respective Manager and/or the Occupational Health and Safety Manager or their representatives.

4.2 Investigation Team -

- Craft Supervisor or Manager
- Safety/Environmental Specialist (SES)
- Occupational Health & Safety Services Representative
- Second Safety/Environmental Specialist
- Appropriate craft representation from Substation Training

4.3 Local Investigation Team -

- Craft Supervisor
- Safety/Environmental Specialist
- Communicate with Occupational Health and Safety Services Representative and appropriate craft representative from Substation Training (participation optional)

All investigations involving a third party will be conducted by SCE Claims

5.0 Incident Communications

The responsible Manager, where an incident occurs, after investigating the incident, will prepare a written summary identifying the root cause with recommendations to limit the possibility of recurrence. The summary shall be communicated to all Substation work locations in a timely manner, not to exceed ten (10) working days. (EXCEPTION: Investigations conducted by SCE Claims)

6.0 Incident Follow-up

Follow-up on recommendations for vehicle accident, injury and illness prevention is important in preventing a recurrence and maintaining employee adherence to rules, policies and procedures. Methods of follow-up include, but are not limited to, the following:

1. Safety Meetings - discussion of incident(s)
2. Training School topic - develop specific training
3. Occasional email reminder by craft supervisor to affected craft group
4. Direct Observation - the direct supervisor of the involved employee shall monitor the employee's work habits and submit a memo to the employee's file 90 days from date of occurrence, noting compliance.

7.0 Employee Compliance

To remain competitive, Substations must maintain a safe and healthy work place for employees and establish methods to reduce industrial injuries and illnesses. In support of existing preventive programs, a consistent, aggressive approach in reviewing incidents will include a program of responsible action.

Our established progressive disciplinary process will apply to incidents involving employee negligence and/or violation of rules, policies or procedures. *Each employee is personally accountable for their individual safety and work practices*. This SOM policy applies to incidents that result in an industrial injury/illness and vehicle accidents or damage to Company property.

SF3: Sleeve Length Policy When Hot or Cold Washing

1.0 Background

Currently there are no written policies or guidelines that exist to address sleeve length when washing insulators in substations. In addition, APM and OSHA rules have been reviewed and no rules exist that directly address this subject. It has been determined that hot or cold washing insulators in substations can be done safely without the use of long sleeve shirts.

2.0 Policy

Long sleeve shirts are not required when hot or cold washing insulators in substations. This policy does not supersede any other APM rules that apply to clothing.

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SF4: Lockout/Tagout Procedure

1.0 General

1.1 This procedure establishes minimum requirements for lockout/tagout of energy sources to machinery or power tools that could cause injury to personnel by inadvertent movement during cleaning, repairing, servicing, and adjusting. All employees and contract personnel must comply with this procedure. This procedure is not intended to include high-voltage equipment located in switchyards (for example, condensers, circuit breakers, and so forth).

1.2 The following procedure was developed to comply with Cal-OSHA CCR Tile 8, Section 3314 in regards to the Injury and Illness Prevention Program.

2.0 Cleaning, Repairing, Servicing, and Adjusting Machinery and Power Tools

2.1 Machinery or power tools capable of movement should be stopped and the power source deenergized or disengaged and, if necessary, the moveable parts should be mechanically blocked or locked to prevent inadvertent movement during cleaning, servicing, or adjusting operations.

2.2 Whenever outside servicing personnel are to be engaged in the cleaning, repairing, or servicing of machinery and power tools, this lockout/tagout procedure should be followed.

2.3 Lockout refers to the use of devices, positive methods, and procedures which effectively prevent unexpected inadvertent movement of machinery or power tools. When the energy source is placed in a safe position with an approved warning tag attached, this is defined as tagout.

3.0 SAP Numbers for Lockout Devices

SAP Number for Lockout Devices

Lockout Device	SAP Number
Lockout	10065453
Padlock 3"	10065452
Padlock 1-1/2" Shackle	10065451
Safety Tag	10135030

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SF5: Entering Underground Vaults with Cable Shields Attached to Surge Arresters

1.0 General

Surge arresters are installed in underground transmission vaults where the cable shields are not grounded. The reason for not grounding the shield is to stop circulating current from flowing on the shield. The surge arresters are connected between the cable shield and ground to prevent over-voltages during switching or faults. The cable shields are always grounded in the adjacent vault, at the riser pole, or at the substation riser.

2.0 Procedures

2.1 Entering the Vault

A. If the circuit is energized, hot line orders shall be obtained and the system operator shall notify the person in charge before the status of the circuit is changed.

B. If the circuit is de-energized, if required, the crew entering the vault will obtain a clearance. If the circuit has not been cleared, a safeguard shall be requested. In addition, it shall be understood between the system operator and the person in charge that the status of the circuit shall not be changed unless the person in charge has been notified.

C. If the vault contains two circuits, then either A. or B. above shall be required on each circuit.

D. Personnel shall not be allowed in the vault during switching. After switching is complete, personnel should wait five minutes before entering the vault.

2.2 Working in the Vault

A. Inspections, pumping water, or other minor repair jobs not involving the cable will require no other procedures except procedure 2.1.

B. Pulling cable, splicing, or other construction type jobs shall require that a personal ground be applied to the cable shield at the splice. The cable shield shall be worked as though it is energized at 5 kV in accordance with APM, Rules 207, 305, and 306 until it is grounded. This requires that rubber gloves be worn while the tape is being removed or replaced at cable shield connector and that live line tools will be used to connect or remove the ground.

2.3 To apply personal grounds, cut the tape away from connector between cable shield and the conductor going to the surge arrester. After using an approved voltage tester, apply a ground between this connector and the 4/0 BC ground wire by using live line tools.

2.4 Make sure not to get between different cable shields while removing the insulating tapes.

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SF6: Checking and Observing Procedure for Work (Other Than Switching) in Substations

1.0 General

1.1 When work in an energized substation facility requires personnel or equipment to be in close proximity to energized conductors or equipment, and the nature of the work has the potential to encroach on the minimum approach distance, a checker is required to be present during the work.

1.2 When the work, by its nature, does not require personnel or equipment to work in close proximity to energized conductors or equipment, and any encroachment would require an arbitrary and independent act, an observer may be used in place of a checker. However, management reserves the right to require the presence of a checker whenever it is warranted by the situation.

1.3 Only qualified personnel will be designated as a checker or observer. These checkers or observers will assure themselves that personnel are working within the parameters of the applicable clearances or within the designated safe work area.

A. Qualified Checker

A qualified checker is a person who is knowledgeable about substations and their inherent hazards and is thoroughly trained and familiar with all specific hazards of the job to be performed, including safe work distances and all applicable APM rules. They are qualified by SCE management.

B. Qualified Observer

A qualified observer is a person who is knowledgeable about substations and their inherent hazards and is capable of understanding the status of energized conductors or equipment to prevent workers from entering hazardous work areas which would require a checker. They are qualified by SCE management.

2.0 Checking Outside Agencies

2.1 When any work is to be done in energized substations by other outside agencies, the job shall first be reviewed by the person in charge of the work with the responsible substation supervisor to determine the need for a checker or observer.

2.2 If the checker or observer notices any person working in an unsafe manner, he or she must immediately notify the worker of the problem. If the problem continues, the checker or observer must stop the work and notify the person in charge of the work or the SCE supervisor.

2.3 Refer to APM, Rule 408, for more information.

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SF7: APM Rule 128 Clarification (Barrier Tape and Guard Rails)

1.0 General

1.1 This policy is intended to clarify APM, Rule 128, which addresses Barrier Tape and Guard Rails.

1.2 The SC&M organization identified a need to clarify APM, Rule 128 with regards to SC&M's work and responsibilities.

1.3 APM, Rule 128 is still applicable to SC&M in its entirety.

2.0 APM, Rule 128 Clarification

2.1 APM, Rule 128 requires Hazards to be marked off with barrier tape and floor openings and openings in walkways to be guarded by a cover, a standard guardrail, or shall be constantly attended.

2.2 SC&M's broad range of work may require items other than barrier tape to be utilized in surrounding the Electrical hazardous area. Alternate methods of surrounding the Electrical hazard may be utilized after discussion during the tailboard, i.e. Telescoping barricade kits, cones, flashers, tape and combinations of such.

2.3 Where possible, there shall be a minimum setback of 12 inches from the hazard to the barricade identifying the hazard.

2.4 The method of identifying an exposed opening in a floor or trench is to utilize the telescoping safety barricade kit for openings at SC&M work locations. Refer to SC&M Letter L-010.

2.5 For openings with perimeters larger than the telescoping safety barricade kits can identify, standard practices currently used in accordance with APM, Rule 128 may be used along with alternative barriers after discussion at the tailboard (Step 2.2).

2.6 All applicable safety rules and procedures shall be used to ensure personnel safety, such as:

A. Safe approach distances

B. Use of a checker

C. Proper grounding techniques

D. Use of a proper and effective Tailboard

E. Job supervisor approval

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SF8: Removing Stored Energy from Previously Installed Circuit Breakers, Prior to Shipment

1.0 General

1.1 This policy is in place to ensure the safety of personnel receiving and handling used circuit breakers, circuit switchers, etc. that have been removed from service to be evaluated for re-purposing or salvage.

1.2 The term "circuit breaker" used in this policy applies to circuit breakers, circuit switchers and any other equipment that may have stored energy.

1.3 The Substation Construction and Maintenance (SC&M) department has identified a need to detail the proper preparation of a previously installed circuit breaker, prior to shipment. This policy details the shipping requirements of previously installed circuit breakers as it relates to stored energy.

2.0 Releasing Stored Energy

2.1 It is the responsibility of the Substation Maintenance Foreman, or his delegate, to ensure that the stored energy has been removed, from any previously installed circuit breaker, prior to shipment.

A. It is the responsibility that any person or work group, removing a circuit breaker from service, to notify the Maintenance Supervisor that a circuit breaker needs to be evaluated for stored energy prior to shipment.

2.2 The circuit breaker must be in the "open" position and all forms of stored energy must be discharged from the circuit breaker before it may be tagged for shipment. This includes, but is not limited to:

A. Spring pressure, including "pre-loaded"

B. Hydraulic pressure

C. Gas pressure, including SF6, air, & nitrogen

D. Electrical, such as capacitors. Bled off and shorted

2.3 This policy does not apply to any ancillary springs, etc. that would require the dismantling of the circuit breaker components or removal of parts.

A. Any dismantling or parts removal from circuit breakers must be performed by personnel trained in these types of functions.

This is to prevent shipping and receiving personnel from being injured by a stored energy release while handling the circuit breaker.

3.0 Proper Labeling for Shipment

3.1 All circuit breakers shall have a "TOFEE" tag filled out and affixed to the circuit breaker in a conspicuous location (mechanism door handle, frame, and so on).

A. This should be filled out by the entity that removed the circuit breaker, void the red "Stored Energy Removed" section.

Figure SF8–1: : TOFEE Tag

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

052453

SUBSTATION
DISCONNECTED ELECTRICAL EQUIPMENT
— STORAGE TAG —

COMPLETED BY:
SUPERVISOR

REMOVED FROM USE:
DATE: _____
ORIGINATING STATION: _____
SAP/W.O. ACCT: _____
POSITION: _____
EQUIPMENT TYPE:
☐ Transformer ☐ Oil Circuit Breaker
☐ Oil Switch ☐ Bushing
☐ Electromechanical Relay ☐ Voltage Regulator
☐ Other: _____
SERIAL #: _____
(If No Serial #, Mark N/A)

SUPERVISOR NAME: _____
SUPERVISOR PHONE #: _____

HOLD FOR EVALUATION: X

COMPLETED BY:
SUPERVISOR / TSS

EVALUATION:
SAMPLING: .....
REPAIR: .....
RETROFILL: .....
REUSE: .....
CLAIMS / LITIGATION: .....

COMPLETED BY:
SAMPLER

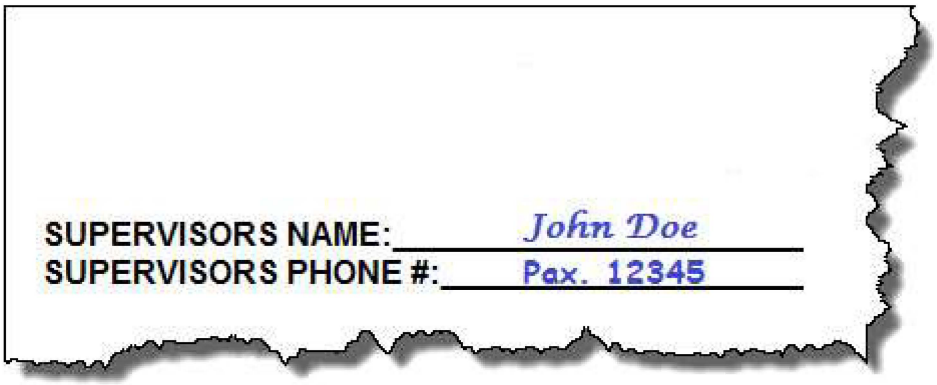
SAMPLE DATE: _____
SAMPLE ID: _____
(If Serial #, Mark S/N)
SAMPLED BY: _____
PCB LAB REPORT #: _____
PCB SAMPLE RESULTS: _____ PPM

THIS EQUIPMENT CAN BE USED AT NUMEROUS LOCATIONS IN OUR SYSTEM.

SCE OD 579 REV 9/00 (CW)

B. The Site Supervisor's name and phone number must be entered where indicated and the "STORED ENERGY REMOVED" yes box shall be checked (Yes ?) by the Maintenance Supervisor or his delegate.

Figure SF8–2: : TOFEE Tag

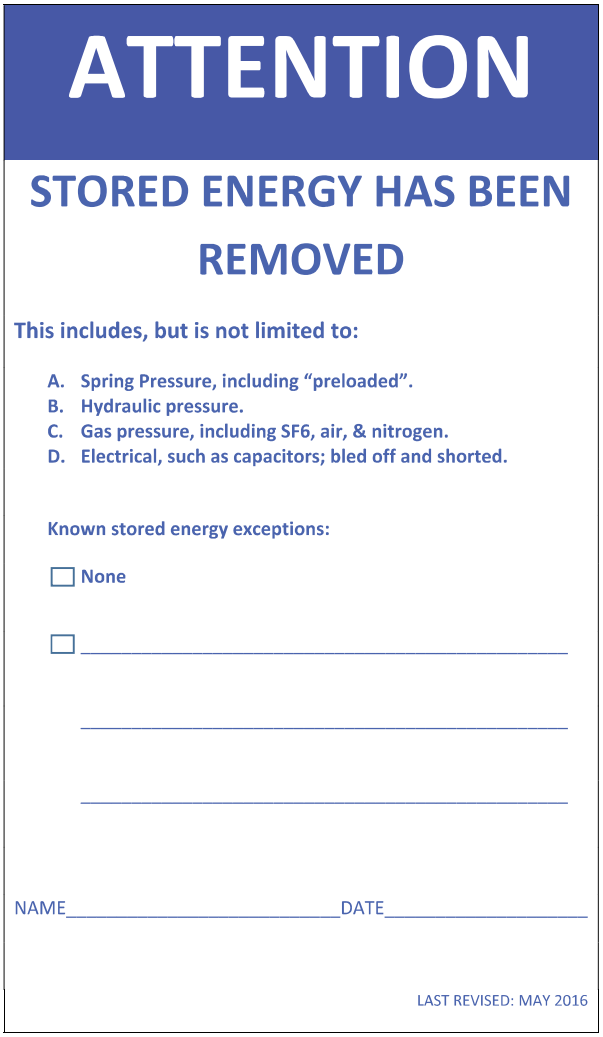


3.2 In addition to the "TOFEE" tag indicated in 3.1, Substation Maintenance Electricians must also complete the "ATTENTION, STORED ENERGY HAS BEEN REMOVED" sticker and affix it in a conspicuous location on the circuit breaker mechanism door.

NOTE

In the event that the CB should be shipped with stored energy, it shall be noted on the bottom of the sticker in the space provided.

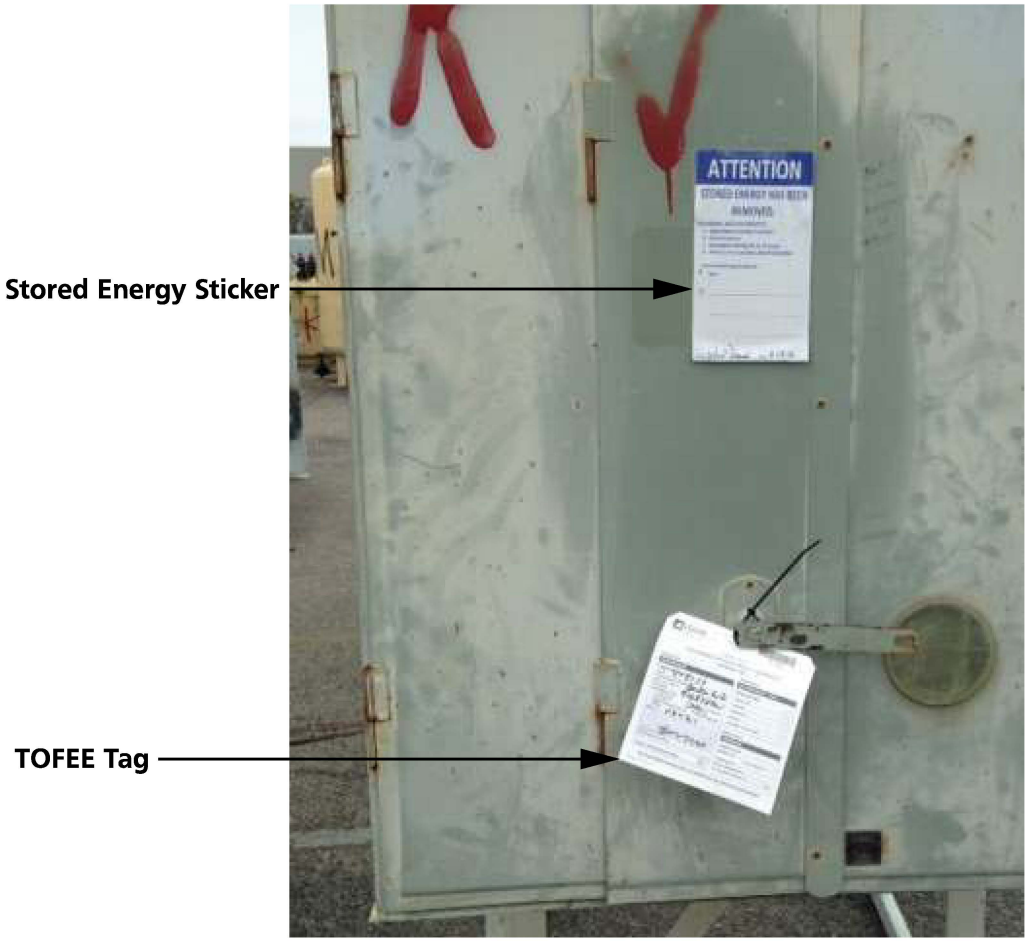
Figure SF8–3: : Stored Energy Sticker (SAP 10206237)



The name of the person applying the sticker must be written on the sticker along with the date it was applied. Once this sticker has been applied, the mechanism energy must not be restored.

3.3 Circuit breaker with all stored energy released and properly labeled for shipment.

Figure SF8–4: : Proper Labeling



SF9: Substation Vegetation Management Policy

1.0 General

This policy is intended to clarify expectations from Substation Management for proper vegetation risk inspections when entering a substation. This policy is intended to be in addition to existing APM and Corporate Vegetation Management protocols.

Any changes to this policy will require the thorough review for its respective impact to standard EDSL 06-90-01 by Standards Engineering and the sponsor of the change(s).

2.0 Policy

When anyone enters a substation to do an inspection, or to perform work, the following SCE Vegetation Management protocols shall be observed and reported:

- Trees and other vegetation that are not in compliance with EDSL 06-90-01.
- Trees that could fall into the energized equipment.
- Trees that could blow into or have foliage that could blow into the energized equipment.
- Dried vegetation that poses a fire risk.
- Vegetation that encroaches into the clear zone around the perimeter of the sub.
- Vegetation growing inside of the substation that could encroach into the Minimum Approach Distance.
- Vegetation growing outside the sub that could encroach into the Minimum Approach Distance.

When any of the above conditions are observed the person finding them shall:

- Create a Notification (Field Tool User)
- Notify the local switching center:
  - — System Operator Contacts SC&M Facility Maintenance Supervisor
  - — Facility Maintenance Supervisor determines strategy for mitigation
    - Work to be completed by:
      - — Utility workers
      - — CBRE
      - — Vegetation Management

When reported, the SC&M Facility Maintenance Supervisor in conjunction with the Vegetation Management team and/or CRE approved vendor, will create and execute a plan to mitigate the risk identified. This may include:

- De-energizing the station
- Clearing portions of the switch rack
- Mitigating the tree risk inside or outside the station, with a checker
- Mitigating the tree risk with an observer

3.0 References

1. Electrical Design Station Layout (EDSL)
   Site Development – Station Perimeter Landscaping 06-90-01

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SF10: Substation Weed Management Policy

1.0 General

1.1 This policy is intended to clarify expectations from Substation Management for proper weed inspections and maintenance expectations when working in a substation. This policy is intended to be in addition to existing APM, MIM (GO174) and Corporate Weed Management protocols.

2.0 Policy

2.1 When anyone enters a substation to do an inspection, or perform work, the following SCE weed management protocols shall be observed and reported:

- Weeds that could grow into the energized switchrack.
- Weeds that could blow into or foliage that could blow into the energized switchrack.
- Dried vegetation that poses a fire risk

2.2 When any of the above conditions are observed the person identifying them shall:

- Create a Notification (Field Tool User, if so equipped)
- Notify the local switching center:
  - — System Operator Contacts SC&M Facility Maintenance Supervisor
  - — Facility Maintenance Supervisor determines strategy for mitigation (Note: FMS will create notification if original person is not Field Tool User)

    Work to be completed by:
    - Utilitymen
    - CRE/CBRE

2.3 When reported the SC&M Facility Maintenance Supervisor and, if needed, CRE approved vendor, will create and execute a plan to mitigate the risk identified. This may include:

- Mitigating the weed risk inside or outside the station, with an observer.
- De-energizing portions of the station (e.g., Cap Rack).
- Clearing portions of the switch rack.

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Section P: Personnel

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P1: Substation Personnel

1.0 General

1.1 In order to ensure accuracy and safety when performing duties, it is fundamental that all personnel are mentally and physically fit. While on duty, employees must be alert and ready to cope with an emergency at all times. To meet this requirement, each individual must be in full command of his/her faculties at all times. Sleeping on the job is a serious dereliction of duty and warrants termination.

1.2 In accordance with corporate policy and the *Accident Prevention Manual* (APM), employees under the influence of alcohol or mind-altering drugs, or who are otherwise mentally or physically unfit to perform assigned duties shall not be permitted to work.

1.3 Operators are not to be relieved from duties by an individual who is not in the proper condition to assume responsibilities of the position. If there is any doubt as to the condition of the person reporting for duty, consult the supervisor or on-call supervisor.

1.4 Employees are not to indulge in any practice which may adversely reflect themselves or Southern California Edison (SCE) while in the performance of their work.

2.0 Inquiries

Employees may receive inquiries or complaints regarding SCE or its operations that they are not authorized to answer. Employees should explain that they cannot answer the questions. It is very important that the employee take the party's name, address, and phone number and advise them that the inquiry will be reported to the supervisor. All this information must be imparted to the supervisor with the explanation that the party is expecting to hear from someone at SCE authorized to answer such inquiries.

3.0 Emergencies

In case of an emergency which may result in injury, property damage, or adverse public relations, the supervisor or employee in charge may take action necessary to handle the specific emergency. In any such case, the person acting shall be fully accountable for his/her actions.

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P2: Employee Notification of Absence

1.0 General

1.1 It is the responsibility of each employee when sick, injured, or for any other reason unable to report to work to notify his/her supervisor or the on-call supervisor. This notification should be made as far in advance of the starting time as possible so that any necessary personnel replacement may be arranged.

1.2 In the event the employee cannot reach the supervisor, the employee is to call the nearest Switching Center and inform the on-duty operator that he or she has attempted, unsuccessfully, to contact the supervisor. The operator is to be given all pertinent details such as the type of sickness or injury, expected duration of absence, and a telephone number where the employee may be reached. The operator will determine if an attempt has been made by the employee to reach his/her supervisor prior to accepting this message. This notification process should only be used as a last resort if all possible avenues to contact the supervisor or on-call supervisor have failed. The operator will contact the supervisor and provide him/her with the information as quickly as possible.

2.0 Responsibility of the Supervisor

2.1 The supervisor should call the employee back if all the necessary details of the absence were not received.

2.2 It is important that the supervisor determine if the absence is the result of job-related industrial accident or sickness. Sometimes when employees have been off work for extended periods of time, it is not until they return to work that the absence is determined to be job related. Strict governmental industrial accident reporting requirements no longer permit such delays.

2.3 Each supervisor will be held accountable for strict adherence to this policy.

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Section O: Operating

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O1: Operations and Switching Order OD 245

1.0 General

The purpose of any written switching order is to provide the switcher with a document indicating the switching to be performed and the order in which it should be accomplished. In addition, it also provides the basic medium for a check and double-check procedure to ensure complete and accurate accomplishment of each step. A switching order form (OD 245) will be prepared and used in connection with all switching that is not documented on an approved program or procedure or which cannot be switched in a manner that the issuing operator and switcher are in direct communications. A properly prepared switching order, when used correctly, will ensure a complete and safe operation.

2.0 Procedures for Issuing and Using the OD 245

Prior to the issuance of any orders, a tailboard must take place between the issuing operator, switcher, and checker, if available. If the checker cannot participate in this tailboard, the switcher will tailboard the necessary switching with the checker prior to the start of switching. During the tailboard, the exact status of the equipment or line must be established and all parties must be familiar with the methods to be used in switching the equipment.

2.1 Switching Center

The actual preparation of the OD 245 at the switching centers may be done by any person directed to do so by the system operator in charge. However, it will be the responsibility of the system operator to review the order, sign, and read the orders from the OD 245 to the switcher. The switcher will then take the order and read the steps back to the issuing operator. The checker, if available, will confirm his/her understanding of the orders. Before leaving the control room, the issuing operator, switcher, and checker, if available, shall proceed to the control board and review the proposed switching using the mimic bus, if so equipped. The yellow tags denoting switching in progress shall be placed on the control handles at this time. When the switching is completed, the switcher and checker will return to the control room, arrange the mimic bus and dispatch board, and hand the completed order to the issuing operator. The switcher will verbally report the switching to the issuing operator, who will check it against the written order. The checker will confirm his/her agreement with the switching performed. The issuing operator will repeat the orders.

2.2 Unattended Stations

At normally unattended stations, the OD 245 may be prepared in advance, as the orders are issued, or from notes, if necessary. After the written order is completed, it will then be read back to the issuing operator and confirmed. Under no circumstances shall any order be used for switching that has not been read back to the issuing operator from the actual form that will be used for switching. After the switching order has been confirmed, the switcher will review it with the station one-line and the status of the station at that time. The switcher will place tags denoting switching in progress on the proper control handles prior to going into the switchrack.

2.3 Switching Method

During the preparation of the order, and throughout the entire switching and reporting procedure, strict formality shall be observed. No unnecessary conversation that could contribute to any deviation from the job at hand is allowed. Upon arrival at the location of the equipment to be switched, first check to confirm that the position is correct and the switching steps will accomplish the intended results. Immediately following the completion of each step, the switcher or checker must place a primary check mark in the appropriate location on the switching order to indicate that it is complete.

When the next uncompleted step requires the switcher to relocate from inside to outside or vice versa, or go to another position, a review of the order must be made confirming the completion of each proceeding step and a second check mark made to indicate the operation was completed correctly. When relocating to the new location, it is equally important that the correct position is again verified and that the intended switching will be correct.

3.0 Details for Preparation of OD 245 Forms

A single OD 245 or set of OD 245 Forms must be prepared for each separate switching purpose. When there is more than a single designated piece of equipment or a single voltage level, the person preparing the order must take care to properly designate each switching step in order to avoid confusion or misunderstanding.

Ground symbols shall be placed just to the left of the operations column on the OD 245 to indicate the operation of ground disconnects (red when ground disconnects are closed, and blue when opened).

Each detailed step will only have one operation per line. See Figure 1 for examples.

Figure–1: Switching Order OD 245 Form (Sample 1 of 2)

SWITCHING ORDER

Page 1

Station Metropolitan Date 2-19-82 Sequence No. 1

Reason For Switching Put the East 16 kV Line on Transfer Bus, and Clear CB for Maintenance to Overhaul

Equipment Designation East 16 kV Line and Bus Tie 16 kV

OPERATION	SWITCHING	CHECK
Open	Bus Tie CB	✓
Check	Bus Tie CB Open	✓
Close	Bus Transfer Bus Disc.	✓
Close	Bus Tie CB	✓
Check	Parallel	✓
Open	East CB	✓
Check	Load Up on Bus Tie	✓
Check	East CB Open	✓
Open	East Line Disc.	✓
Open	East Bus Disc.	✓
	NOTE: Detailed equipment designation on each step.	

Issued By Smith Time 10:30

Completed By Jones Time 10:45 Checker [illegible]

Figure–2: Switching Order OD 245 Form (Sample 2 of 2)

SWITCHING ORDER

Page 1

Station Metropolitan Date 2-21-82 Sequence No. 1

Reason For Switching Clear #1 Bank 66/16 kV, Testmen to Changes Taps

Equipment Designation #1 Bank 66/16 kV

OPERATION	SWITCHING	CHECK
Check	66 CB Open	✓
Check	16 CB Open	✓
Open	66 kV Bank Disc.	✓
Open	66 kV Bus Disc.	✓
Open	16 kV Bank Disc.	✓
Open	16 kV Bus Disc.	✓
	NOTE: Detailed equipment designation on each step.	

Issued By Smith Time 15:15

Completed By Jones Time 15:35 Checker

SCE 130-285 (Rev 2/OM)

4.0 Definition of Form Sections

4.1 Reason For Switching — State why the equipment or line is being switched and, when known, the work that will be done.

4.2 Equipment Designation — This line should contain the exact nomenclature or designation of the equipment involved. Where a single designated piece of equipment is to be switched, it will not be necessary to name the equipment in each detailed step. However, when more than one piece of equipment or voltage level is involved, care must be taken to properly identify each step in order to avoid misunderstandings or confusion.

4.3 Page Number — Each OD 245 must be numbered in its proper order for completing the switching operation. If the switching requires more than one OD 245, do not complete the last line. Instead, write “continued” on this line. It will not be necessary to fill in the station, date, or reason for switching on other than the first page of multiple order pages.

Sequence number are used to differentiate between orders involving two or more separate switching purposes. For instance, if more than one piece of equipment is to be switched, such as a bank and a line, without the operator returning to the control room, the single OD 245 or sets of OD 245s will be designated by use of a sequence number. The first set of orders would be designated as Sequence No. 1, at the completion of which the second set of orders, designated Sequence No. 2, would be used to complete the second switching purpose.

4.4 The check column on the right side of the form is the area that will be used to primary-check mark and double-check mark each step.

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O2: Use of the Qualified Switching Checker

1.0 General

1.1 The role of the qualified switching checker is one of paramount importance. The qualified switching checker must become an integral part of each switching operation and must share the accountability for the correctness and execution of the switching performed. If a qualified person is on the station property at the time when switching is performed, that person shall make every effort to be available to be used as a Checker, and the Acting Operator is expected to use a Checker when one is available. Only a person who has been deemed a qualified switching checker will be allowed to perform the duties of a switching checker.

1.2 A qualified switching checker is defined as an individual that has successfully completed the Substation Acting Operating Course and/or is qualified by management as trained in switching techniques and the hazards involved with switching. A supervisor may be used as a checker, when available.

1.3 The qualified switching checker should participate in the original tailboard. If this is not possible and a checker is secured while en route to perform the switching, a tailboard will be held at that time. This is to acquaint the qualified switching checker with what is to be accomplished and what switching will be done. The qualified switching checker must make certain that the intended switching is correct before giving his/her confirmation.

1.4 Verbal communication is a vital part of each operation maneuver. Do not use visual indications only.

1.5 Remember, switching involves important company resources. All switching is important and requires the concentrated efforts of everyone involved. Never try to check and perform some other task at the same time. Checking is a full time job.

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O3: Minimum Trips of Equipment and Line Protection

1.0 General

1.1 The system operator at each switching center is responsible for ensuring that the protective relay minimum trips are not exceeded.

1.2 In all cases where the work requires shifting of load during routine or emergency conditions, the protective relay equipment will be checked to see that additional load will not affect or exceed the following:

- Line relay minimum trip
- Bus/bank relay minimum trips
- Fuse capacity minimum melt
- Any other protective equipment minimum trip that would restrict the system from carrying load when picking up additional load on stations or line

1.3 It is important that the peak loads be taken into consideration and not random readings that do not reflect maximum loads when transferring load to other lines or facilities.

1.4 Any time 80 percent of the minimum trip on lines or equipment is anticipated due to switching or load transfers, station supervision or the Distribution representative will be notified and a review of the switching shall be made.

1.5 When peak loads are unknown, an acting operator will be required to monitor all load transfers.

1.6 The operator should be familiar with the OD 43 reports and the OD 45 cards that are placed in protective relays. The system operator should review these two items when determining the capability of the protective equipment.

1.7 If the protective relay capabilities are unknown, the Test Technician assigned to the area will be consulted.

1.8 The minimum trips of the line will be marked on the ammeter. If the minimum trip is changed, the individual making the change will be responsible for remarking all equipment and meters at the time the change is made.

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O4: Loading of Distribution Power Transformer Banks

1.0 General

Power transformers are not expendable and are not to be overloaded to the threshold of failure. Transformers can carry overloads for varying periods of time without damage to the winding insulation. The duration of this time is dependent upon the immediate prior loading, the top oil temperature at the beginning of the overload, and the ambient temperature. These factors determine the length of time before the transformer temperature limits are reached. Transformer temperatures are the basis for loading.

2.0 Planned Loading

The planned loading limit of a transformer bank shall be equal to 100 percent of its nameplate rating (adjusted for parallel operation) if no thermal capability study has been done. If a thermal capability study has been completed, the planned loading limit is set by the heat run and may be as high as 130% of the bank's rating (adjusted for parallel operation). This is the maximum continuous loading available provided the top oil temperature does not exceed 115°C. The Operator should know the loading of the transformer banks under his/her jurisdiction and be able to forecast the areas reaching these load levels. If the bank ammeter readings indicate a possibility of exceeding these limits, the Distribution Operations Center should be kept informed of the situation. The DOC will arrange to have the load shifted to another source where possible. Substation Management should be informed and load should not be deenergized without his/her knowledge.

3.0 N-1 Loading

If the normal number of transformer banks at a location is reduced by the failure of any one bank, an N-1 condition exists. The N-1 emergency loading limit shall be 130 percent of the bank's nameplate rating (adjusted for parallel operation) if no thermal capability study has been done. If a thermal capability study has been done, the N-1 emergency loading limit is set by it and may be as high as 145 percent of the bank's nameplate rating (adjusted for parallel operation), provided the top oil temperature does not exceed 130°C. These limits shall not be exceeded without permission from Substation Management. It is conceivable that at some locations, at the onset of an N-1 condition, the load on a transformer bank might exceed the N-1 emergency load limit. For the short period of time required to transfer load, if the top oil does not exceed the 130°C limit, there may not be cause to drop load.

In both planned and N-1 load conditions, speed is of paramount importance. Good and concise communication with Distribution Operations Center personnel is required to accommodate a quick and orderly transfer of load. The final judgment will be exercised by Substation Management as to when or if load is to be dropped.

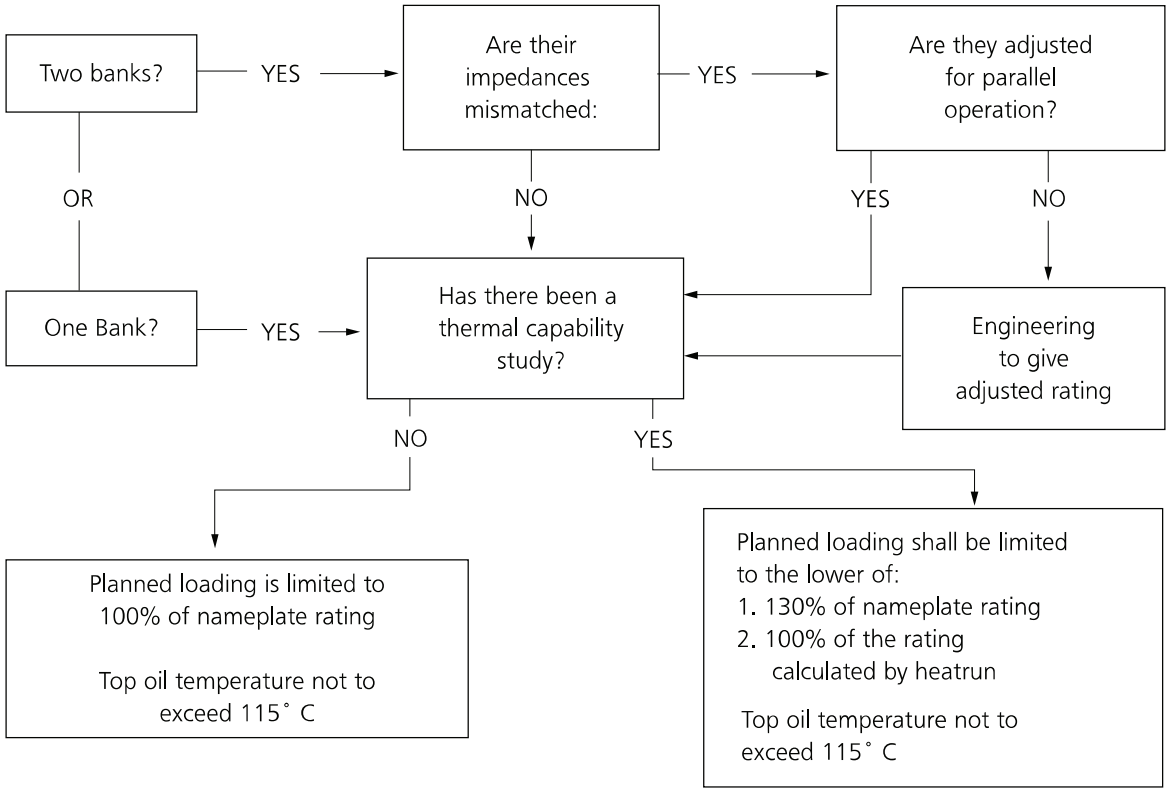
A transformer bank located in a customer substation shall not be loaded to more than its nameplate rating.

N-1 rating is not to be used for planned or routine outages for working on equipment.

The planned and emergency loading limits for 115/33 kV power transformer banks shall be established by Engineering on an individual basis.

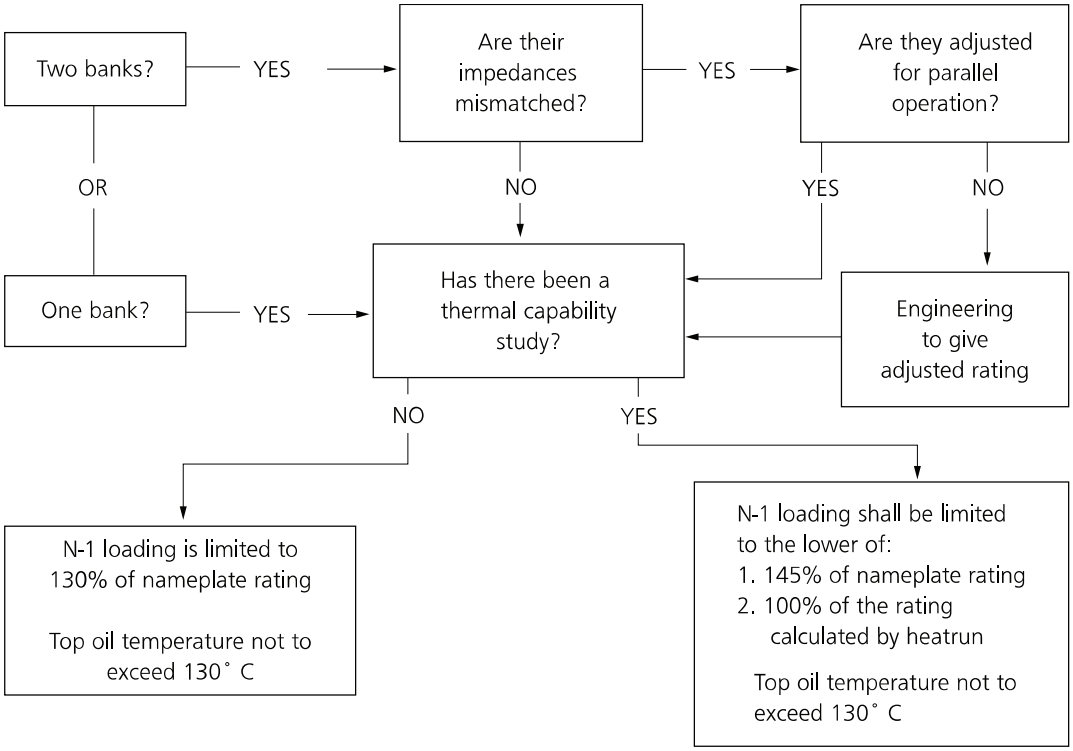
Any “DECLARED EMERGENCY” by a Manager or his representative, which states the equipment must be removed from service “IMMEDIATELY”, will constitute an N-1 condition.

Figure–1 : Planned Loading of Distribution Power Transformer Banks



All percentages based on transformer nameplate rating. Any deviation from the following criteria can be authorized by Substation Manager or an appointed representative

Figure–2 : N-1 Loading of Distribution Power Transformers



All percentages based on transformer nameplate rating.

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O5: Re-energizing Distribution Power Transformer Banks Following a Relay Operation

1.0 General

Substation transformer banks are not expendable and care must be taken at all times to prevent severe overloading or excessive fault currents.

Re-energizing a relayed transformer bank prior to inspecting should be done only as a last resort to restore service or to relieve a damaging overload on other equipment.

Good judgment, which is of paramount importance, must be exercised at this point in time and is the responsibility of the System Operator. Supervision should be notified and consulted as soon as possible.

2.0 Knowledge

Every operator should have a conceptual idea as to what action he/she would take if a transformer bank was lost at any time of the day, with the conditions that would prevail at that time. Some of the factors to be considered are:

1. Is load interrupted?
2. The amount and length of time of overloads in excess of N-1 on the remaining sources.
3. Response time of Operator and Troublemen.
4. Has the transformer received an automatic test?
5. Immediate availability of alternate source.
6. Top oil temperature.
7. Type of relay operation.

3.0 Re-energizing A Transformer Bank After it has Relayed

If a transformer relays on overload or neutral overload, check for targets on all circuits, open any circuits showing targets and reclose the transformer once for test. If the transformer again relays on overload or neutral overload, open all circuits carried from the transformer. Then, energize the transformer and reclose the circuits one at a time until the trouble is located. Leave the faulted circuit out and pick up the remainder of the load.

If the differential relays have operated, every practical effort should be made to inspect all equipment within the differentially protected area before attempting to re-energize the transformer bank.

This inspection should include insulators, bushings, equipment connected to the transformer bank leads on the high- and low-voltage sides, presence of oil and/or smoke expelled from the transformers, blown explosion diaphragm, or excessive gas pressure.

If no damage is observed, or if the damage is confined to broken porcelain and the conductors are clear of shorts and grounds and load is off, the transformer bank should be re-energized for test. Good judgment, based on the factors stated above, must be used before testing the transformer bank.

4.0 Automatic Test

Some substations are equipped to automatically test transformer banks after a relay operation. After such a test, the bank must not be energized again until the cause has been determined and corrected.

When a transformer bank relays on sudden pressure, an inspection should be made of the transformer prior to closing for test. However, if supervisory control is available and load is off or the remaining transformer banks are severely overloaded, a test by supervisory control can be made prior to anyone arriving at the substation.

If a transformer bank relays on excessive or thermal overload, open all circuits carried from the transformer bank and re-energize the transformer bank and the low- voltage bus and close the circuits in sequence as specified by the Distribution Department until the load on the transformer bank reaches the N-1 loading limit. The load and temperature of the transformer bank must be closely monitored. The top oil temperature limit (130°C) must not be exceeded without specific permission from the appropriate substation manager.

O6: Operation of Circuit Regulators

1.0 General

1.1 A circuit regulator is a device for maintaining a constant voltage at a given point regardless of the load flow through the regulator. This is accomplished by adding to or subtracting from the voltage source.

A. Circuit regulator loading limits are as follows:

- Circuit regulators have a Normal loading limit of 130% of nameplate.[1/]
- Ratings above normal may be approved by the Regional Manager only after a thorough study of the regulator and operating conditions is performed by Field and Apparatus Engineering.

1.2 When de-energizing a substation distribution circuit regulator the parallel will be broken on disconnects, and the regulator will be de-energized using a Circuit Breaker (CB).

A. Deviation from this rule requires either the use of disconnects designed for this purpose or the permission of the responsible supervisor.

1.3 Circulating current (a flow of volt-ampere reactive power [VAR]) is caused by a difference in voltage between two circuits. Circulating current may be calculated by comparing the sum of the amperes of the two circuits before and during parallel. Circulating current must be limited to 50 amperes for parallels, which will be broken inside the station and to 75 amperes for parallels, which will be broken in the field, as these are the maximum amounts that can safely be broken on station- or pole-type disconnects.

1.4 Triplex induction may be adjusted while in parallel on a station bus, provided care is exercised while making these adjustments to minimize circulating current. All regulators may be adjusted while in field parallel. Where step-type regulators are to be adjusted, care must be exercised to introduce enough impedance in order to minimize circulating current.

2.0 Parallels

2.1 Station Parallels

A. Before attempting to parallel any regulated circuit with another, all concerned regulators will be placed on the neutral position and off control. Regulators must not be placed on automatic control when operating in parallel.

[1/] Voltage Regulator loading capabilities are depending on the amount of percent regulation. To have the Normal loading limit of 130%, the regulation must be limited to 6%.

2.2 Field Parallels

A. If the field parallel is to be made between the feed point and the station, on either or both circuits, both regulators should be placed on neutral and off control. This also applies when the feed point is very close to the station or if the load is connected between the station and the feed point.

B. Field parallels beyond the feed point of both circuits require that the concerned regulators be blocked on step-in the as-found position and place in off control. Regulators shall not be placed on automatic control while in parallel.

O7: Operation of Secondary Switches

1.0 General

1.1 The operation of secondary switches (CT rotos, potential, DC, pilot wire/communication disconnects, and so forth) can be critical to the sensitivity of relaying systems and loading levels of equipment. All personnel that will operate, or order the operation of, secondary switches are to be familiar with the requirements for their operation.

1.2 To reduce the possibility of an accidental interruption of service and to be in compliance with other rules, bulletins, and orders, the following rules have been established.

2.0 Operation of Secondary Switches Using an Approved Procedure

2.1 An approved procedure is one that is used routinely to switch out station equipment. It must be approved and signed by station supervision.

2.2 When secondary switches are operated using an approved procedure, it is not necessary to log the individual steps in the attended and unattended station logs.
Instead, a statement shall be entered in the attended electronic log and unattended log book that shall identify:

A. Status of switched relay protection including rotos, potential secondary, pilot wire/communication disconnects and circuit breaker bypass knife switches. This statement shall reflect the time the switching was completed. (Ref. SOM G5: Substation Logs).

2.3 When secondary switches are to be operated using an approved procedure, it is not necessary to obtain individual switching orders from the switching center.

2.4 When secondary switches are to be operated, the set up and operation of CT Roto switches shall be accomplished utilizing both the Acting Operator and the Checker at the point of making the associated protection solid. This effort is intended to ensure that both personnel identify and operate the correct device.

3.0 Operation of Secondary Switches for All Other Switching

3.1 When routine work is to be performed on equipment where the improper operation of or failure to operate secondary switches may result in the interruption of service, the operation of secondary switches (CT rotos, potential, DC, pilot wire/communication disconnects, and so forth) is to be included in the program request.

A. The person initiating the program request will determine secondary switch operation requirements.

B. If a definite sequence of operation of secondary switches is essential, the sequence is included in the program request.

3.2 The operation of secondary switches will be accomplished using normal switching techniques and logged in accordance with SOM G5: Substation Logs

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O8: 500 kV Substation Switching

1.0 General

Any time that routine primary 500 kV substation switching is performed, there will be two qualified operators present for the duration of the switching. The switching operator and checker may be any qualified operator. The only exception is in case of emergencies when a checker is not available.

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O9: Reporting Storm Damage Assessmentsw

1.0 General

In order to provide corporate management with estimated damages and costs incurred during unusual system conditions, a "Storm Damage Reporting" procedure was initiated by Power Supply Department in 1979. This procedure is still in effect today and the only modification has been to revise the form.

A direct quote from the 1979 letter follows:

"Since the actual damage and costs cannot be immediately identified, a daily cumulative total will be kept using the work sheet any time the listed conditions occur and until reasonably accurate final costs are estimated. The report to Corporate Management will be made whenever the costs exceed $100,000 total for the Department. The estimated costs should be called to the Power Supply Department office by 0800 each morning, starting with the first day of the incident."

This instruction establishes the reporting system to be used by Substations and this administrative procedure will establish the requirement for reporting storm damage to management.

2.0 Reporting Format

The attached form will be used by the field in reporting damage to management. The preparation of this form is fairly simple. Two areas do require some comment:

2.1 Last Report

The figures shown on these lines will always be the figures from the previous day's "This Report" column.

2.2 This Report

The figures reported are not the incremental additives to the "Last Report" but rather a new gross total for the damage.

3.0 When to Report

Each work location has the responsibility to report to management whenever an unusual system condition occurs. This report should be made by 0830 each morning, starting with the first day of the incident and then followed with daily reports until reasonably final costs are estimated.

Reports can be submitted by fax or by phone. When an unusual system condition occurs system wide, it will be necessary for each region to report even if they have not incurred any damage.

4.0 Work Order Accounting

Separate work orders are prepared in accordance with ESM 7.3.12. The value of the work orders should relate to the dollars reported in the Storm Damage Assessment for each division.

A requirement of ESM 7.3.12 is the preparation of work orders for each storm or storm system. This requires a decision to distinguish between the end of one storm and the beginning of another.

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Region_____ Date_____

STORM DAMAGE REPORT

FROM:_____ _____ DATE _____ TIME

TO: _____ _____ DATE _____ TIME

SUBSTATION

Type of Storm: __ Rain __ Wind __ Lightning
__ Heat __ Fire __ Flood
__ Snow/Sleet __ Earthquake/Earth Slide

	LAST REPORT	THIS REPORT
Storm Related Workhours Expended:	$_____	$_____
Cost of Materials Used:	$_____	$_____
Estimated Future Workhours for Repairs:	$_____	$_____
Estimated Cost for Future Use of Materials:	$_____	$_____
Estimated Contract Costs:	$_____	$_____

Description of Damage: _____

_____

TRANSMISSION

Type of Storm: __ Rain __ Wind __ Lightning
__ Heat __ Fire __ Flood
__ Snow/Sleet __ Earthquake/Earth Slide

	LAST REPORT	THIS REPORT
Storm Related Workhours Expended:	$_____	$_____
Cost of Materials Used:	$_____	$_____
Estimated Future Workhours for Repairs:	$_____	$_____
Estimated Cost for Future Use of Materials:	$_____	$_____
Estimated Contract Costs:	$_____	$_____

Description of Damage: _____

_____

	SUBSTATION	TRANSMISSION	TOTAL
Total Estimated Plant Expenditure:	$_____	$_____	$_____
Total Estimated Related Expenditure	$_____	$_____	$_____
Total Gross Estimated Expenditure:	$_____	$_____	$_____

O10: Circuit Breaker Clearing (CBC) and Circuit Breaker Analysis (CBA) Procedures for Substations

1.0 General

1.1 Written, pre-approved switching procedures are critical to the clearing of substation equipment in a timely and efficient manner for substation Maintenance and Test personnel performing work.

1.2 Circuit Breaker Clearing (CBC) and Circuit Breaker Analysis (CBA) procedures are switching tools that have been developed for a given substation and voltage in order to execute switching according to a pre-approved switching procedure.

1.3 CBC and CBA procedures are developed with the cooperation and approval of both the responsible switching center's Operations and Maintenance and, for some CBC procedures, Test personnel. Test is to approve only CBC procedures that have been also approved for relay routine use. The procedures shall be written by the responsible Operations personnel and then reviewed by the responsible Maintenance personnel, and when applicable, by Test personnel. Final electronic approvals shall be obtained from the Maintenance and Operations, and when applicable, the Test Supervisor.

1.4 The CBA procedures have been developed specifically for Maintenance Electricians and may not be used by any other craft.

1.5 The CBC procedures have been developed specifically for Maintenance and Test Personnel and may not be used by any other craft to clear equipment. When Test technicians use 4 or 12 or 16kV CBC procedures for relay routines, the following statement must be included in the notes: **"THIS PROCEDURE WILL WORK FOR 4 or 12 or 16KV LINE RELAY ROUTINES ONLY. THIS PROCEDURE CANNOT BE USED FOR BANK OR BUS RELAY ROUTINES."**

1.6 System Operators may use the CBC procedure as a reference guide. However, the Acting Operator at the unattended station **MUST** utilize an OD 245 to record and perform the switching issued by the System Operator and all switching shall be logged in the unattended station log, including all appropriate symbols.

1.7 The use of a CBC or CBA procedure does not eliminate the need to submit a program request with the appropriate switching center and in accordance with all applicable programming policies and guidelines.

1.8 A "valid" CBC procedure requires SDMS electronic signatures from the Operations and Maintenance Supervisors, and when the procedure can be used for relay routine, the Test Supervisor, as signatures confirm the accuracy and safety of the procedure.

A "valid" CBA procedure requires SDMS electronic signatures from the Operations and Maintenance Supervisors, as signatures confirm the accuracy and safety of the procedure. **Any procedure dated after March 8, 2004 that does not have valid SDMS electronic signatures from the Operations and Maintenance Supervisor and, when applicable, from Test Supervisors shall not be used.**

NOTE

In the Substation Document Management System (SDMS), if an edit is made to an already "approved" document there will be an entry under the "Edit History" heading of the SDMS document placeholder. This automatic log entry indicates that an alteration of some type has taken place, or that the document was "saved". Either of these actions makes the document in question no longer an "approved" valid document, and therefore will require the document to be initiated again for approval by Operations and Maintenance Supervisors, and when applicable, by Test Supervisors.

1.9 The CBC and CBA procedures utilize the 'Move' format. The Move format allows the Electrician(s) or Test technician to skip through the procedure in any sequence desired after receiving permission from the System Operator, while maintaining the procedure concept. The responsible Maintenance and Test personnel will be held accountable for selecting the correct Move for the desired results.

1.10 Following the discovery of abnormal conditions during a substation inspection, a comprehensive Tailboard discussion will be conducted between the Acting Operator and the Jurisdictional Switching Center System Operator. Should adjustments be deemed necessary, it is permissible to amend the step and remove subsequent steps as appropriate. It is mandatory to prioritize safety by ensuring that three-way communication is utilized when amending CBA/CBC procedures. Example: When a Distribution crew has No Test Orders on a line.

Original step — Make the Carreon16kv recloser solid. Check
Edited step — ~~Make~~ the Carreon 16kv recloser solid.
Original step — Make the Carreon 16kv recloser Auto.
Edited step — ~~Make the Carreon 16kv recloser Auto.~~

NOTE

When a Distribution crew is utilizing fast curve settings for incident energy reduction, the applicable Circuit Breaker will be skipped per SOB 326.

This is not intended to bypass procedures that are outdated and in need of revision.

2.0 Circuit Breaker Clearing Procedure

2.1 An approved Circuit Breaker Clearing (CBC) procedure is a tool developed for a specific substation and voltage and is designed to clear substation equipment. The individual switching Moves may be used as the body of a switching program to clear specific pieces of equipment.

2.2 Formatting guidelines for a CBC procedure are as follows:

A. A statement at the beginning of the procedure will state that the station and system status will allow the procedure to be utilized.

B. Every page of the procedure shall have a heading, providing the name of the substation, the voltage of the CBC procedure, the identifiable date for the procedure and a page number.

C. Every CBC procedure shall be entitled "XX kV Circuit Breaker Clearing Procedure" Example:

Beverly Substation
16 kV Circuit Breaker Clearing Procedure
Date: January 1, 2011

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D. A procedure cover sheet shall be a separate page and contain instructions and special notes pertaining to any peculiar conditions at the respective substation. The following statement will be included in the notes section when Test is using a Distribution CBC procedure for relay routines:

THIS PROCEDURE WILL WORK FOR 4 or 12 or 16 KV LINE RELAY ROUTINES ONLY. THIS PROCEDURE CANNOT BE USED FOR BANK OR BUS RELAY ROUTINES.
Under the Site Specific section if the station capacitors are controlled by the Distribution Voltage VAR Control (DVVC) program, the following statement should be added:

DISTRIBUTION VOLTAGE VAR CONTROL (DVVC) IS IMPLEMENTED AT THIS SUBSTATION ON THE 4 or 12 or 16 KV OPERATING BUS. THE DISTRIBUTION BUS-CONNECTED SUBSTATION CAPACITORS CAN BE AUTOMATICALLY CONTROLLED BY THE DVVC ALGORITHM. WHEN THE SUBSTATION CAPACITORS ARE IN DVVC CONTROL, A CONTROL STATUS WILL BE SHOWN NEXT TO THE CAPACITOR CB/SWITCHER IN EMS INDICATING IF THE CAPACITOR IS UNDER DVVC CONTROL, AND THE CAPACITOR CONTROLS AT THE STATION MUST BE ON MANUAL. A CONTROL INHIBIT TAG IS TO BE APPLIED IN EMS TO THE SUBSTATION CAPACITOR CB/SWITCHER WHEN THE CONTROL FUNCTION OF THE OPERATING EQUIPMENT IS TO BE BLOCKED; THIS WILL PREVENT SUPERVISORY CONTROL OF THIS POINT ON THE EMS SYSTEM.

E. A separate page will be used for each switching Move. Each move identifier will be in bold print (**MOVE I**). At the end of each move there will be the following station in bold print: **PROCEED TO DESIRED MOVE.**

F. Each step of the procedure is to be numbered with double-spacing between steps. Steps will be numerically sequenced from the beginning to the end of the procedure.

G. The step "**IF DUCTOR IS REQUIRED**" will be in bold type and indented 2 inches.

H. Each step of the procedure required for ductoring will be indented 3 inches and will be identified with an alpha letter.

I. The procedure is to have a two-inch margin on the left-side of the page.

J. The procedure is to be written in Times New Roman, size 12 font.

K. There shall only be one operation per step. Any 'check steps' are to be identified as a numbered step.

L. All switching shall be included in the procedure; this includes primary and secondary switching and any Maintenance switches.

M. Reclosers shall be made solid prior to beginning disconnect switching in a position. Reclosers shall remain solid until disconnect switching is completed for that position.

N. Capacitor circuit breakers and switchers shall be included in the procedure and their sequence determined by station supervision. The Switching Center shall be contacted before starting the switching to clear the capacitors.

O. The Bus Tie circuit breaker shall be the first circuit breaker operated and tested in the procedure (exception: as noted in Step 3.2 (M) below).

P. A statement to verify each **"___ KV CB IS OPEN AND CLEAR OF GROUNDS"** shall be included and identified as a numbered step.

Q. All circuit breaker CT rotos shall be turned out to ductor and shall be a lettered step.

R. Each bank circuit breaker will be tested with its respective voltage whenever possible.

S. The initial MOVE to prepare a station voltage for a CBC procedure shall be entitled **"MOVE ____ PRELIMINARY SETUP"**. Each subsequent circuit breaker will have a 'MOVE' to identify the switching steps necessary to test the circuit breaker and return it to service. The final MOVE to return the station voltage to normal shall be entitled **"MOVE ___ RETURN STATION TO NORMAL"**.

T. If the operation of rotos involves a third party, the first step following "**IF DUCTOR IS REQUIRED**" will be **"CONTACT THE SYSTEM OPERATOR PRIOR TO PROCEEDING"**. The System Operator shall contact the third party for the operation of the roto.

2.3 The CBC procedure was created with the necessary steps included to clear a circuit breaker and to operate CT rotos for ductoring and testing. It is not necessary to call the System Operator when operating rotos as a step contained in the CBC procedure. It is also not necessary to log the operation of these rotos in the unattended station log. (**Exception 1:** as noted in Step 2.2 (T) above. **Exception 2**: if a circuit breaker is to be left cleared overnight with the CT rotos turned out, then this will be logged with the CT margin symbol in the unattended station log and the station status communicated to the System Operator).

2.4 The CBC procedure was developed to allow Maintenance and, when applicable, Test personnel the ability to select the appropriate Moves for the work planned. Maintenance and Test personnel may select the Move within the CBC procedure that clears the capacitors without performing other Moves, if they are not required. Maintenance and Test personnel will be held accountable to select the correct Move for the desired results.

2.5 The CBC procedure's individual Moves may be used to program the clearing of one or more circuit breakers, one at a time; however, the programming rules and guidelines still apply. The Maintenance and Test Supervisor shall submit an Outage Request with the appropriate Switching Center. The System Operators and supervision will be required to review and sign the program sheet, as with any other program request.Maintenance and Test personnel, upon arriving at the unattended substation must get verification from the System Operator that they

have the same dated procedure and that the station status will allow the work to be done. The System Operator will then give permission to start the CBC procedure.

3.0 Circuit Breaker Analysis Procedure

3.1 An approved Circuit Breaker Analysis (CBA) procedure is a tool developed for a specific substation and voltage and is designed to parallel circuit breakers with the Bus Tie, or to open circuit breakers one at a time on a double-operating bus station configuration.

3.2 Formatting guidelines for a CBA procedure are as follows:

A. A statement at the beginning of the procedure will state that the station and system status will allow the procedure to be utilized.

B. Every page of the procedure shall have a heading, providing the name of the substation, the voltage of the CBA procedure, the identifiable date for the procedure and a page number.

C. Every CBA procedure shall be entitled "XX kV Circuit Breaker Analysis Procedure" Example:

Beverly Substation
16 kV Circuit Breaker Analysis Procedure
Date: January 1, 2011

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D. A procedure cover sheet shall be a separate page and contain instructions and special notes pertaining to any peculiar conditions at the respective substation.

E. Under the Site Specific section if the station capacitors are controlled by the DVVC program the following statement should be added.

DISTRIBUTION VOLTAGE VAR CONTROL (DVVC) IS IMPLEMENTED AT THIS SUBSTATION ON THE 4 or 12 or 16KV 12KV OPERATING BUS. THE DISTRIBUTION BUS-CONNECTED SUBSTATION CAPACITORS CAN BE AUTOMATICALLY CONTROLLED BY THE DVVC ALGORITHM. WHEN THE SUBSTATION CAPACITORS ARE IN DVVC CONTROL, A CONTROL STATUS WILL BE SHOWN NEXT TO THE CAPACITOR CB/SWITCHER IN EMS INDICATING IF THE CAPACITOR IS UNDER DVVC CONTROL, AND THE CAPACITOR CONTROLS AT THE STATION MUST BE ON MANUAL. A CONTROL INHIBIT TAG IS TO BE APPLIED IN EMS TO THE SUBSTATION CAPACITOR CB/SWITCHER WHEN THE CONTROL FUNCTION OF THE OPERATING EQUIPMENT IS TO BE BLOCKED; THIS WILL PREVENT SUPERVISORY CONTROL OF THIS POINT ON THE EMS SYSTEM.

F. A separate page will be used for each switching Move. Each move identifier will be in bold print (**MOVE I**). At the end of each move there will be the following station in bold print: **PROCEED TO DESIRED MOVE.**

G. Each step of the procedure is to be numbered with double-spacing between steps. Steps will be numerically sequenced from the beginning to the end of the procedure.

H. The procedure is to have a two-inch margin on the left-side of the page.

I. The procedure is to be written in Times New Roman, size 12 font.

J. There shall only be one operation per step. Any 'check steps' are to be identified as a numbered step.

K. All switching shall be included in the procedure; this includes primary and secondary switching and any Maintenance switches.

L. Reclosers! shall be made solid prior to beginning disconnect switching in a position. Reclosers shall remain solid until disconnect switching is completed for that position.

M. Capacitor circuit breakers and switchers shall be included in the procedure and their sequence determined by station supervision. The Switching Center shall be contacted before starting the switching to clear the capacitors. Capacitor circuit breakers shall have bus disconnects opened for an CBA procedure. Shorting and ground disconnects will not be closed in an CBA procedure.

N. The Bus Tie circuit breaker shall be the first circuit breaker operated and tested in the procedure (**exception:** as noted in Step 3.2 (L.) above).

O. Each bank circuit breaker will be tested with its respective voltage whenever possible.

P. The initial MOVE to prepare a station voltage for an CBA procedure shall be entitled "**MOVE ____ PRELIMINARY SETUP**". Each subsequent circuit breaker will have a 'MOVE' to identify the switching steps necessary to test the circuit breaker and return it to service. The final MOVE to return the station voltage to normal shall be entitled "**MOVE ___ RETURN STATION TO NORMAL**".

Q. Any deviation from an approved CBA procedure will require the use of an OD 245 Switching Order.

4.0 Programming the Procedure

4.1 The use of a CBC or CBA procedure does not eliminate the need to submit a program request with the appropriate switching center and in accordance with all applicable programming policies and guidelines.

4.2 The Maintenance or Test Supervisor/Upgrade Supervisor shall submit an Outage Request with the appropriate switching center under the normal programming rules and guidelines. The System Operator will review the Outage Request, locate and identify the most up-to-date procedure, note the date of the procedure and develop a program cover sheet for the dates and times requested by the Maintenance Supervisor/Upgrade Supervisor or Test Supervisor. The System Operators will be required to review the program cover sheet, as with any other program request, to ensure the date on the actual procedure matches the date on the program cover sheet and sign the program cover sheet.

5.0 Executing the Procedure

5.1 On the day the respective procedure is to be started, Maintenance and Test personnel will search the Substation Document Management System (SDMS) for the most up-to-date, ***approved and valid*** procedure. The Maintenance and Test personnel will print the most up-to-date copy of the CBC or CBA procedure prior to leaving his/her work location and s/he will take it to the job location.

5.2 Upon arriving at the job location, the Acting Operator will perform pre-switching technique and report the status to the System Operator.

5.3 Maintenance and Test personnel shall get verification from the System Operator that they have the same dated procedure and that the station status will allow the work to be done. The System Operator will then give permission to start the CBC or CBA procedure.

5.4 Once verification that both procedures are dated the same and permission has been given to start the procedure, Maintenance and Test personnel may work through the procedure until the work is completed for the day (**exception**: clearing capacitors requires a phone call to the System Operator before switching).

5.5 At the end of the day a recap of the work completed, along with a statement indicating the abnormal station status shall be communicated to the System Operator. The Acting Operator at the unattended station shall record a statement of work completed in the unattended station log book (**example**: “completed Moves I and II”) and an abnormal status at the unattended station with margin symbols, if applicable. Counters are to be logged.

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O11: Distribution Recloser Setting Policy

1.0 General

1.1 This policy is regarding substation circuit breaker auto-reclosers. The reclose settings shown below in Table 1 are associated with percentage of underground circuits.

The goal of the Distribution Reclose Settings Policy is to limit the number of failed automatic reclosing attempts ("bad test") a circuit is exposed to while still attempting to isolate the trouble and pick up customer load. The reference to non-automated versus automated as shown in Table 1 refers to whether Remote Control Switches (RCS) have been installed on the circuit.

Automated Circuit Definition: An automated circuit is defined as a circuit that has a mid-point RCS that has its Loss of Voltage Actuation (LVA) set to operate automatically.

Non-Automated Circuit Definition: A non-automated circuit is defined as a circuit that either does not have a mid-point RCS or that does not have a mid-point RCS with its LVA set to operate automatically.

Table–1: Policy for Substation CB Recloser Settings

Policy for Substation CB Recloser Settings		
	Circuit % Underground	
	0 to 95%	96 to 100%
— 12–33 kV Non-Automated	— 1 Shot – (Test at 15s)	Manual Test[a/]
— 12–33 kV Automated	— 2 Shot – (1st test @ 15s & 2nd Test @ 55s)	— 1 Shot – (Test @ 55s) Refer to Section 3.3
— 2.4–4 kV Non-Automated	— 2 Shot – (1st test @ 15s & 2nd Test @ 55s)	
— 2.4–4 kV Automated	— 2 Shot – (1st test @ 15s & 2nd Test @ 55s)	

[a/] Relay will be set to 1 Shot (1st Test@ 55s), made solid at the relay, and CB recloser on EMS will need to be changed to lower case white "r". All testing for these circuits will be done manually.

NOTE

"Shot" in this document is defined as a close of the CB, energizing the line. In Table 1, "Shot" and "Test" are used interchangeably. One "Shot" equates to two operations to lockout and two "Shot" equates to three operations to lockout.

1.2 The recloser settings for bus-tie position(s) shall be set as follows:

Table–2: Policy for Substation Bus-Tie CB Recloser Settings

Policy for Substation Bus-Tie CB Recloser Settings	
—2.4-33 kV Non-Automated and Automated	—1 Shot - (Test at 15s) a/

[a/] Relay may be made solid for manual test of 96 to 100% Underground Non-Automated Circuits.

1.3 Reclose settings in a distribution circuit requires coordination with field devices such as Remote Controlled Switches (RCSs). In substations reclose settings are set in electromechanical devices, Programmable Logic Controllers (PLCs), and Intelligent Electronic Devices (IEDs). During a permanent fault condition, the timing sequence for the second test will be at 55 seconds for electromechanical devices, PLCs and IEDs

NOTE

During a momentary fault followed by a second fault condition:

- IED devices will perform a second test at 40 seconds from the moment of the second fault.
- Electromechanical devices and PLCs will perform a second test at 55 seconds from the initial fault condition.
- Some old electromechanical device reclosing timing may be different and verification is highly recommended.

1.4 An SAP notification process is used to capture and track the need to initiate or change reclose settings at the substation.

1.5 SAP is the repository of substation recloser settings for distribution lines. Substation Test Department is responsible for updating and maintaining the Standard Station Instructions (SSIs) per SOM G2: Standard Station Instructions (SSI) and Other Substation.

1.6 This policy is intended to be followed in conjunction with DOM SW-11 Attachment 1.

2.0 Department Responsibilities

2.1 In Attachment 1 in this policy, each box describes the task that the responsible department must perform before handing off to the next department. The responsible department is designated at the bottom of each box in bold lettering.

2.2 The transactions between departments are by means of email unless otherwise noted.

3.0 Switching Requirements

3.1 The overall goal of the distribution recloser settings are to limit the number of bad tests a circuit is exposed to while still attempting to isolate the trouble and pick up customer load. The reference to non-automated vs. automated as shown in Table 1, refers to whether Remote Control Switches (RCS) have been installed on the circuit and whether they are automated.

NOTE

Sectionalizing and testing listed below can change depending on whether trouble calls are received indicating possible cause.

3.2 For non-automated 12–33 kV 96–100% UG circuits, engineering has determined that there is a high probability that the circuit will test bad. For these circuits, it is preferred to wait the 30 seconds and allow the automated mid-point RCS to open (if available) or manually open the mid-point RCS. Once the System Operator verifies the mid-point RCS as being open, the circuit shall receive 1 manual test. If the test is bad, close the Tie RCS picking up the back half of the circuit. Continue to sectionalize and test as necessary to maximize load restoration and isolation.

3.3 Automated 12-33 kV 96-100% UG circuits will receive 1 automated test. For these circuits it is required to allow the automated mid-point RCS to open after 30 seconds (dead line). The first test will be at 55 seconds. If the circuit tests bad, the System Operator will need to verify the mid-point RCS as being open, and close the Tie RCS picking up the back half of the circuit. Continue to sectionalize and test as necessary to maximize load restoration and isolation.

3.4 Non-automated 12–33 kV 0-95% UG circuits will receive 1 automated test. First test will be at 15 seconds. During this test, no field switches have operated and testing will be 100% of the circuit. If the circuit tests bad, the System Operator will need to manually open the mid-point RCS (if available) and provide a second test. If the second test is bad, the System Operator will need to close the Tie RCS picking up the back half of the circuit. Continue to sectionalize and test as necessary to maximize load restoration and isolation.

3.5 Automated 12–33 kV 0-95% UG circuits will receive 2 automated tests. First test will be at 15 seconds. If this test is bad, the automated mid-point RCS will open at 30 seconds (dead line). The circuit will then receive the second test at 55 seconds. If the circuit tests bad on the second test, the System Operator will need to verify the mid-point RCS as being open, and close the Tie RCS picking up the back half of the circuit. Continue to sectionalize and test as necessary to maximize load restoration and isolation.

NOTE

See Section 3.8 for Tie Device Restoration Logic (TDRL) Pilot Project on automatic closing of the Tie RCS.

3.6 Non-automated 2.4–4 kV circuits will receive 2 automated tests. During these tests, no field switches will operate and testing will be 100% of the circuit. If the circuit tests bad, the System Operator will need to manually open the mid-point RCS (if available) and provide a second test. If the second test is bad, the System Operator will need to close the Tie RCS picking up the back half of the circuit. Continue to sectionalize and test as necessary to maximize load restoration and isolation.

3.7 Automated 2.4–4 kV circuits will receive 2 automated tests. First test will be at 15 seconds. If this test is bad, the automated mid-point RCS will open at 30 seconds (dead line). The circuit will then receive the second test at 55 seconds. If the circuit tests bad on the second test, the System Operator will need to verify the mid-point RCS as being open and close the Tie RCS picking up the back half of the circuit. Continue to sectionalize and test as necessary to maximize load restoration and isolation.

3.8 Tie Device Restoration Logic (TDRL):

For automated 12-33 kV 0-95% UG circuits, some of these circuits may have integrated Tie Device Restoration Logic (TDRL) via DMS, which will close the Tie RCS automatically during front-fault conditions only if all TDRL sequence of events are executed. If circuits include TDRL, then it can be verified through EMS. The TDRL required sequence of events to execute an automatic closing of the tie are as follows:

Table–3: : TDRL Sequence for CB 2-Shot Reclosing Test

Time (Seconds)	Event	TDRL Process Sequence/State
Pre-Trip	Ready	If System Operator has selected TDRL as enabled, then the TDRL will transition to the "Ready" state if devices are in the following conditions: · Circuit A: CB Closed, Recloser Auto, Mid-Point RCS Closed and LVA auto · Circuit B: CB Closed, Recloser Auto, Mid-Point RCS Closed · Circuit AB: Tie-Point Open, Tie Device AC Status Restored · Loading Check Passes · Check for Control Inhibit · Check for Telemetry Failure · Device Malfunction Status Check **Note:** At every step, the program continually checks devices are in expected states.
0	Substation CB Open	TDRL Records "Trip" state and EMS/DMS status updated · TDRL starts monitor timer (configurable). · TDRL will run until timer ends and either complete successfully or stay in last executed state recorded.
15	Substation CB Closed	TDRL Records "Test1 Closed" state. · TDRL monitor and timer Continues **Note:** If test is good, circuit is restored and TDRL time will expire. TDRL will reset the scheme by returning to "Enabled" state. TDRL will transition to the "Ready" state if devices are in the expected states.
15	Substation CB Open	TDRL Records "Test1 Open" state and EMS/DMS status updated · Monitor Timer Continues
30 + Netcomm. communications time	Circuit A Mid-RCS Open	TDRL Monitors Mid-RCS Status as Opened · Monitor Timer Continues
55	Substation CB Close	Program Records "Test2 Closed" state and EMS/DMS status updated · Monitor Timer Continues
55+	Substation CB Open	Program Records "Test2 Open" state and EMS/DMS status updated · Monitor Timer Continues

Table–3: : TDRL Sequence for CB 2-Shot Reclosing Test

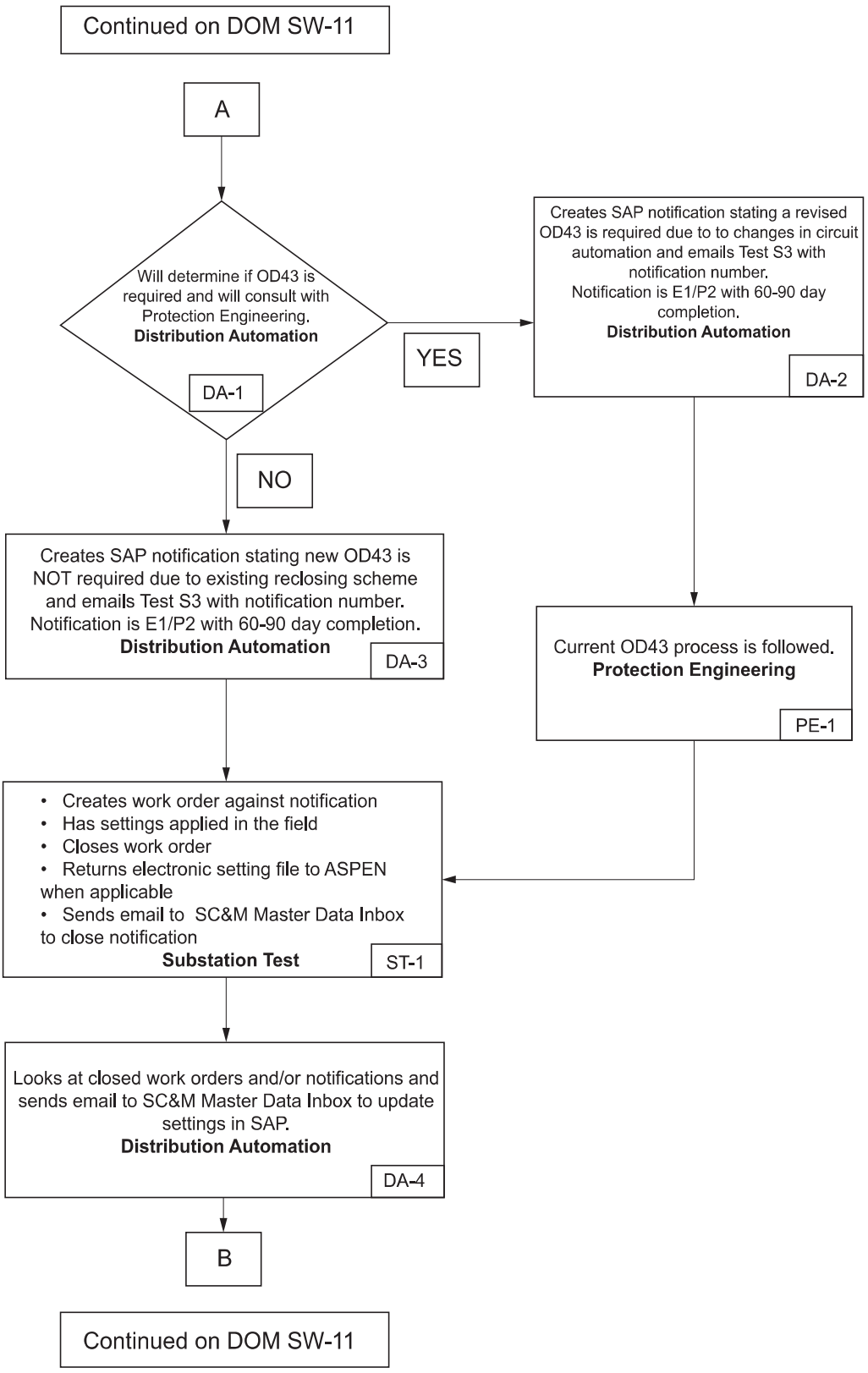
Time (Seconds)	Event	TDRL Process Sequence/State
80	Send Circuit B CB Recloser Solid Command if Devices are in expected state and all previous sequence steps recorded successfully.	If all paired circuit devices are in the expected status and all previous sequence steps have recorded successfully. Monitoring ends. Then performs the following: · Check circuit "A" Mid-RCS "A" Open · Check circuit "B" Mid-RCS "B" Closed · Loading Check - Estimates the combined load on circuit B and the back half of circuit A. Validates the loading check if the calculated load is less than maximum thresholds (80% winter / 70% summer: configurable) of the circuit B minimum trip. · Send out reclose SOLID command to Circuit B Substation CB Recloser. · Program Records "In Progress" state.
84	Circuit B CB Recloser Command Successful	Circuit B CB Recloser Solid Successful, Send out Tie Device Close Command.
120-180	Tie Device Close Command Successful.	Check that Tie Device Close Command Successful. · Program Records "Completed" state if successful · Program Records "Failed" state if not successful

Post Repair and Return to Normal Circuit Configuration		
Operator Control	Manual Operation	Once all circuit repairs are completed and both Circuit A and B are returned to normal, then enabled TDRL and the sequence will start over. **Note:** If any event sequence fails, then TDRL will be in "failed" state or last executed state (scheme status) and Operator will need to determine next step. The process described above demonstrates a TDRL tie close procedure.

If all sequence events are executed and validated, then the Tie RCS will close automatically picking up the back half of the circuit. If any of the sequence events do not occur, then the logic/algorithm will drop from the scheme.

In EMS, System Operators have the ability to enable/disable the logic on the automated circuit, eliminating the Tie RCS from automatically closing. System Operators shall disable TDRL from circuits for abnormal circuit situations such as during No Test Orders, Clearances, Control Inhibits (Tags), abnormal, temporary or permanent circuit re-configurations.

4.0 Attachment 1



O12: Shift Changeover Protocol

1.0 General

In an effort to improve transitions between shifts and ensure Operators coming on shift receive full and complete information that may affect their work during the upcoming shift, the following document is provided to outline the process by which shifts will be "handed off" from one operator to the next.

This is intended to be a simple effort that should be followed during each shift exchange. As always, it is the responsibility of the Operator going off-shift as well as the Operator coming on-shift to properly communicate regarding system status as well as all other conditions which may affect the safe and reliable operation of the system during the upcoming shift.

2.0 Best Practices

At shift change, the Operator going off-shift and Operator coming on-shift will review all items contained on the Shift Changeover Checklist (attached to this document).

2.1 Each applicable item should be discussed in detail such that a thorough explanation of each item on the checklist that could or will affect the reliable and safe operation of the system during the upcoming shift takes place.

2.2 The Operator coming on-shift should have a complete understanding of the current system status and be aware of any items that could potentially have an effect on his/her work.

Both Operators will sign the Shift Changeover Checklist to indicate that they have both reviewed the items on the list and a thorough knowledge transfer between Operators has taken place.

The completed Shift Changeover Checklists (there will likely be more than one checklist per day as a result of multiple desks and shifts) will be attached to the daily log for the day and kept on file at the switching center for a period of time in accordance with the record retention schedule in a manner that supports inspection upon request.

Shift Changeover Checklist

- ☐ **Current Status of the (Substation Name) AOR**
  - ☐ Weather Conditions
  - ☐ Voltage Status and VAR Schedules
  - ☐ Server Status for EMS, OMS, and DMS
  - ☐ GCC or AGCC
  - ☐ Real Time Notifications
  - ☐ Projects-Move Program
- ☐ **Review Log**
  - ☐ Clearances
  - ☐ Interruptions
  - ☐ Current Conditions, Red Flag, Relays, Real Time Switching, etc.
  - ☐ GCC or AGCC
- ☐ **Current Status of the (Substation Name) Distribution System**
  - ☐ Confirm current switching procedures utilizing OMS
  - ☐ Review new abnormal tags/notes
- ☐ **Review Personnel in AOR**
  - ☐ Substation Operators on shift, their location, and present activity
  - ☐ TMs, District, Transmission,Maintenance, Test Crews, Telecomm, Battery Electricians and Utility Persons. etc.
- ☐ **Programs that are scheduled for upcoming shifts printed and reviewed**

Off-Going System Operator _____ DSG Date _____

Oncoming System Operator _____ DSG Date _____

Note(s):

1. This does not eliminate the requirements of Operating Manual Section 6.2. This serves as a reminder and minimum turnover expectation for System Operator on a shift by shift basis.

O13: Circuit Breaker Trip Rings or Front Open/Close Pushbuttons

1.0 General

The purpose of this policy is to define personnel roles and responsibilities when operating a circuit breaker trip ring or front open/close pushbuttons where the circuit breaker fails to open (solid-to-trip).

2.0 Roles and Responsibilities

This section provides employees with allowable expectations from each different work group: Operations, Test, and Maintenance as each plays a different role.

2.1 Grid Operations

Switching orders shall not be given to a Substation Operator to operate a circuit breaker trip ring or front open/close pushbuttons when the CB is solid-to-trip. The expected response to a solid-to-trip circuit breaker scenario shall be to switch around it in order to de-energize and isolate it before opening disconnects to the CB. Each scenario is different and there may be situations in which it may be safe to operate the associated circuit breaker disconnects; however, the disconnects to a solid-to-trip circuit breaker shall not be operated until a discussion takes place between the System Operator and his/her local supervisor (this may include the local Maintenance/Test Supervisor) and all factors are considered. Any deviation from this rule will be at the sole discretion of the local Operations Supervisor.

2.2 Test

Manual tripping of an in service CB, by Test personnel, is permitted if the issue is due to a failed relay or other associated equipment. Other options, such as switching around the CB, can be considered before operating a CB trip ring. If the issue is related to the circuit breaker, action should be taken to isolate the circuit breaker without operating it in order to allow Substation Electricians to assess the situation. Test may operate the trip ring or front open/close pushbuttons for a circuit breaker issue only with approval from the Maintenance Supervisor.

2.3 Maintenance

Manual tripping of an in service CB, by Maintenance personnel, is permitted only with the approval from the Maintenance Supervisor.
At the discretion of the Maintenance Supervisor, a manually actuated, mechanical opening device may be operated to trip an energized CB, but only after performing the following actions.

A. Verify the extent of any mechanical or electrical problems to the safest extent possible.

B. Based on the inspection results and the CB's operating system configuration, the CB may be operated, if it is safe to do so.

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Section MT: Maintenance and Testing

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MT1: Transformer, Regulator, and Oil-Filled Reactor Maintenance

1.0 General

1.1 Proper maintenance and test of transformers, regulators, and oil-filled reactors is essential to good system operations. Maintenance personnel shall have a thorough understanding of the apparatus under their care and be able to perform all of the routine tests, adjustments, repairs, and inspections as needed. All repairs and adjustments will be documented.

1.2 Maintenance is performed on the basis of the condition of the equipment as determined by maintenance personnel. A log and/or history card for each transformer, regulator, or oil-filled reactor shall be kept in the equipment. The date and brief description of the work performed, tests made, and counter readings shall be entered in the log or on the history card. Diagnostic and equipment records shall be retained on file at the crews' work base.

1.3 This order is subject to change as diagnostic equipment and/or test data warrants.

1.4 Refer to the Maintenance and Inspection Requirements for Oil Filled Transformers, Regulators, and Reactors for more detailed information and requirements.

2.0 Guidelines for Internal Inspection of Load Tap Changing and Bus Regulating Equipment on Transformers

2.1 Refer to the Maintenance and Inspection Requirements - Section TR for Oil Filled Transformers, Regulators, and Reactors for a detailed inspection checklist.

2.2 Consult manufacturers manual for specific instructions for internal inspection. The following guidelines shall be considered suggested minimum intervals, as described in Table 1.

Table–1: Guidelines for Internal Inspection of Load Tap Changing and Bus Regulating Equipment on Transformers

Equipment Type	Minimum Intervals for Inspection
Two compartment-circuit breaker type — Transfer Switch	As indicated by OTA (Oil Tap Changer Analysis)
Two compartment-circuit breaker type — Selector Switch	Per Annual DGA Results
One Compartment — Arcing Type	As indicated by OTA
Resistive/Diverter Type	5 Years
Vacuum Type	10 Years (more frequently per wear indicator and DGA results) for all manufacturers except Reinhausen RMVII type LTC. Reinhausen RMVII will be as indicated by DGA and moisture results

3.0 Requirements for Internal Inspection of Line Regulators

Line regulators must be inspected as conditions indicate.

4.0 Spare/Mobile Transformers

4.1 All spare/mobile transformers that will be put in service shall have inspections and tests performed annually as follows:

A. Inspect oil level of all compartments and bushings

B. Inspect nitrogen pressure, if applicable

C. Inspect for oil leaks or damage

D. Power factor tests prior to energizing

E. DGA prior to and 48 hours after energizing

4.2 All spare/mobile transformers not in service shall have the following tests performed:

A. Moisture tests on a yearly basis

5.0 Inspection Guidelines for Auxiliary Equipment on Transformers, Regulators, and Reactors

Inspections, tests, and maintenance on auxiliary equipment shall be performed at one year intervals or as conditions indicate.

Load tap changer mechanisms shall be inspected, cleaned, and serviced per manufacturer's instructions at one-year intervals.

6.0 Diagnostic Testing/Inspections

6.1 One-Year Intervals

Dissolved gas in oil analysis (DGA), including moisture and 6-part shall be taken from main tank and LTC selector compartments, including selector compartments with vacuum bottles (if applicable) on all in-service transformers, bus regulators, and reactors.
In addition, OTA samples shall be taken yearly on all LTCs with arcing compartments, with the exception of diverter-switch type LTC's. All transformers, regulators, and reactors should be visually inspected annually. In addition, all transformers, regulators, and reactors control compartments should be inspected and checked annually.

Dissolved gas in oil analysis (DGA), including moisture and 6-part shall be taken from all LTC selector compartments, including selector compartments with vacuum bottles (if applicable) on all in-service transformers.

Note(s): For transformers equipped with online DGA monitors, manual DGA and six-part samples shall be taken every 5 years.

6.2 Two Year Intervals

Currently not performing any activities that require two year interval diagnostic testing/inspections.

6.3 Five-Year Intervals

Transformers with resistive type (diverter switch) load tap changer shall be inspected every five years.

6.4 Oil Circulating Pumps

A. Cardinal, Harley, Ingersoll-Rand, and all sleeve bearing pumps shall have an internal inspection performed after 10,000 hours of run time or as conditions indicate.

B. General Electric, Renzman-Grunewald, and all other roller or ball bearing pumps shall be inspected as conditions indicate.

6.5 Oil Dielectric Tests

Oil dielectric tests are to be taken from all oil compartments after handling oil, or as conditions indicate. Oil shall test no less than 25 kV (equipment rated 115kV and below) and 30 kV (equipment rated 115 kV and above).

6.6 Load Tap Changer Internal Inspection

Load tap changer (LTC) internal inspections will be performed as indicated by OTA results for arcing type or DGA results for vacuum type compartments. In addition, diverter switches will continue to be inspected every five years in accordance with manufacturer's instructions. The following should be verified:

A. Visual inspection of all associated selector and/or transfer switch contacts

B. Winding Resistance tests through all LTC contacts shall be performed after major contact replacement

C. Hi-potential test of vacuum bottles, if applicable, shall only be performed if suspect

7.0 Field Testing Standards

At the time of installation or relocation, the following applicable tests shall be performed. Refer to the Maintenance and Inspection Requirements for Oil Filled Transformers, Regulators, and Reactors for detailed test requirements and tolerances.

7.1 Turns-ratio/polarity tests through all no-load and LTC positions (if available) when new or relocated. Ratio test performed only on in-service no-load tap position and all LTC positions, if applicable, on in-service transformers.

7.2 Leakage reactance (Impedance) tests on rated voltage no-load tap position listed on transformer nameplate.

7.3 Winding resistance (Bridge) tests through all no-load and LTC positions (if available) when new or relocated. Test only on in-service no-load tap position and all LTC positions on in-service transformers.

7.4 Megger readings of all windings, including external core grounds

7.5 Insulation power factor tests on all windings and bushings.

7.6 Power factor tests of oil before and after filling of equipment

7.7 Test sudden pressure relay

7.8 Excitation tests

7.9 Temperature gauges will be tested for accuracy and set as follows

Table–2: Temperature Gauge Setting Specification

Equipment	B Banks	A Banks	AA Banks
Temperature Gauge: Alarm Set Points			
Top Oil	100°C	100°C	100°C
Winding	130°C	110°C	110°C
Cooling Set Points			
55°C Rise Top Oil			
1st Stage	60°C / 50°C	60°C / 50°C	60°C / 50°C
2nd Stage	N/A	65°C / 55°C	65°C / 55°C
55°C Rise Winding			
1st Stage	65°C / 55°C	65°C / 55°C	65°C / 55°C
2nd Stage	N/A	75°C / 65°C	75°C / 65°C
65°C Rise Top Oil			
1st Stage	65°C / 55°C	65°C / 55°C	60°C / 50°C
2nd Stage	70°C / 60°C	70°C / 60°C	65°C / 55°C
65°C Rise Winding			
1st Stage	75°C / 65°C	75°C / 65°C	70°C / 60°C
2nd Stage	80°C / 70°C	80°C / 70°C	75°C / 65°C

Note(s):

1. All temperatures separated by slash (/), indicates on/off temperatures. Typically, top oil temperatures will control cooling equipment. Future specification change will address using winding temperatures to control cooling equipment as well.

7.10 Check oil level gauges and alarms

7.11 Magnetic type oil gauges used on transformer bushings, conservator tanks, and so forth, shall be tested. This test can be performed by securing a magnet to a disconnect pole and carefully placing the magnet on the face of the gauge. The oil gauge needle will move and should return to its original level when the magnet is removed.

7.12 For nitrogen blanketed transformers, an oxygen test shall be given. Oxygen content should be kept below 3 percent.

7.13 DGA will be taken on all new equipment and all relocated transformers from the main tank and all associated LTC selector compartments prior to energizing and after 48 hours.

7.14 Oil sample from main tank and each compartment shall be sent to a material testing lab for six-part oil tests (H20, IFT, NN, color, dielectric and power factor).

8.0 LTC Filter Systems

8.1 When LTCs are equipped with a filter system, a visual inspection shall be performed annually during the normal LTC M&M inspection.

8.2 The inspection will include checking for leaks in the control cabinet, filtration components, piping, pressure gauges, valves and filter housing. In addition, functionally operating the pump can provide useful information for filter change-out.

8.3 Pressure limits (Table Three) indicate filter replacement is required. Utilize the procedure described in the manufacturer's manual shipped with each filter system for filter replacement. Refer to Table Three for normal operating pressures and pressure limits. The pressure limits in this table indicate when filter replacement is required.

Table–3: Filter System Operating Pressures

Filter System Type	Normal Operating Pressure	Change Filter if Pressure Exceeds	Red Light Indicating Service Required	Replacement Filter Part Number
Filmax	30 – 40 psi	42 psi	*Yes	Velcon #FHD-718-0.5
Reinhausen	3.5 bars or less	3.5 bars	No	Reinhausen #72759500 or #72759600

***Note(s):**

1. The red "Service Required" light indicates one or more of the following conditions exist:
   - Low oil flow
   - Oil leak
   - High oil pressure from blocked line
   - High oil pressure indicating the filter requires replacement

9.0 Transformer Soak Periods Prior to Energizing

9.1 Purpose

The purpose of this document is to define the required processes and procedures for transformer energization.

9.2 Scope

It is important that all vacuum filled transformers have a non-energized oil soak period and an energized no-load soak period. These processes are required to maintain the health and manufacturer's warranty. Refer to Table TR-2 for recommended time periods and notes 1 and 2 for potential deviations.

Non-energized oil soak period allows the transformer insulation system to fully absorb mineral oil and free any remaining air bubbles or pockets trapped within the insulation system. The non-energized oil soak periods for transformers are based on transformer voltage class. The higher the voltage class, the more critical it is to allow the insulation to become fully impregnated with oil.

Energized no-load soak period allows a transformer to be energized and naturally warm up through core magnetostriction. The energized no-load soak period is required prior to applying load on new or cooled down transformers. A cooled down transformer is one which has been de-energized for about a 24 hour period.

Important: Repetitive daily switching which includes transformer de-energizing shall be avoided.

Table–4:

Voltage Class	Non-Energized Oil Soak Period, Hrs.	Energized No-Load Soak Period, Hrs.	
		New Transformer	Cooled Down Transformer
500	72	24	24
230	36	24	12
115	24	8	8
66 and below	12	4	4

Note(s):

1. If the forecasted load is less than 60% of ONAN (OA) rating, cooled down transformers can be returned to service without an energized no-load soak period with all cooling stages manually activated for indicated soak period.
2. Additional considerations to deviate from the above requirements would include top oil temperature, ambient temperature and cooling system functionality. Apparatus Engineering or Technical Staff should be contacted if any deviation is required.

Attachment A: LTC Inspection– Selector/Transfer Type Inspection Sheet

Date:		Inspected By:	
External Visual Inspection of LTC Compartment:			**Comments**
Oil leaks-			
Welds	☐ OK	☐ Leak	
Valves	☐ OK	☐ Leak	
Oil level gauge	☐ OK	☐ Bad	Reading:
Pressure relief device	☐ OK	☐ Bad	
Desiccant color	☐ OK	☐ Light pink	
Selector compartment visual inspection:	☐ OK		
Oil condition	☐ OK	☐ Bad/carbonized	
Main stationary contacts	☐ OK	☐ Bad/pitted	
Main moveable contacts	☐ OK	☐ Bad/pitted	
Reversing switch stationary contacts	☐ OK	☐ Bad/pitted	
Reversing switch moveable contacts	☐ OK	☐ Bad/pitted	
Collector ring contacts	☐ OK	☐ Bad/pitted	
Collector ring condition	☐ OK	☐ Bad/pitted	
Compartment cleanliness	☐ OK	☐ Debris/carbon	
Transfer compartment visual inspection:	☐ OK		
Stationary arcing contact	☐ OK	☐ Bad/pitted	
Moveable arcing contact	☐ OK	☐ Bad/pitted	
Main current stationary contact	☐ OK	☐ Bad/pitted	
Main current moveable contact	☐ OK	☐ Bad/pitted	
Geneva Gears-condition	☐ OK	☐ Damaged	
Charging spring condition	☐ OK	☐ Damaged	
Compartment cleanliness	☐ OK	☐ Debris/carbon	
Motor control cabinet:	☐ OK	☐ Dirty/oil	
Cleanliness	☐ OK	☐ Bad	
Light bulb	☐ OK	☐ Bad	
Heater condition	☐ OK	☐ Faulty	
Drive shaft condition	☐ OK	☐ Loose/damaged	
Gears	☐ OK	☐ Loose/damaged	
Cam/micro switches	☐ OK	☐ Dirty contacts	
Oil leaks	☐ OK	☐ Leak	
Contactor condition	☐ OK	☐ Noisy	
Light bulb	☐ OK	☐ Bad	
Wiring condition	☐ OK	☐ Frayed/discolored	
Motor condition	☐ OK	☐ Bad	
Hand crank power safety switch	☐ OK	☐ Bad	
LTC counter	☐ OK	☐ Bad	
LTC position indicator	☐ OK	☐ Bad	
Oil test:			
Hipot value:	☐ Pass	☐ Fail	
LTC Filter Pump Operational?	☐ Yes	☐ No	
Final counter reading:			

Note(s):

1. Never manually hand operate or check mechanical stops when performing routine inspections on load tap changing equipment when transformer is energized and under load.

Attachment B: Attachment B: LTC Inspection – Selector Only Inspection Sheet

Date:		**Inspected By:**	
External Visual Inspection of LTC Compartment:			**Comments**
Oil leaks-			
Welds	☐ OK	☐ Leak	
Valves	☐ OK	☐ Leak	
Oil level gauge	☐ OK	☐ Bad	Reading:
Pressure relief device	☐ OK	☐ Bad	
Desiccant color	☐ OK	☐ Light pink	
Selector compartment visual inspection:	☐ OK		
Oil condition	☐ OK	☐ Bad/carbonized	
Main stationary contacts	☐ OK	☐ Bad/Pitted	
Main moveable contacts	☐ OK	☐ Bad/Pitted	
Reversing switch stationary contacts	☐ OK	☐ Bad/Pitted	
Reversing switch moveable contacts	☐ OK	☐ Bad/Pitted	
Collector ring contacts	☐ OK	☐ Bad/Pitted	
Collector ring condition	☐ OK	☐ Bad/Pitted	
Geneva Gears-condition	☐ OK	☐ Gulled/Damaged	
Charging spring condition	☐ OK	☐ Damaged/ NA	
Compartment cleanliness	☐ OK	☐ Debris/Carbon	
Oil test:			
Hipot Value:	☐ Pass	☐ Fail	
LTC Filter Pump Operational	☐ Yes	☐ No	
Final counter reading:			

Note(s):

1. Never manually hand operate or check mechanical stops when performing routine inspections on load tap changing equipment when transformer is energized and under load.

MT2: Routine Testing of Protection System Components

1.0 General

1.1 A Protection System consists of five components: Protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices, and station DC supply associated with protective functions (including station batteries, battery chargers, and non-battery based DC supply).

1.2 Protection System components can have different levels of monitoring and be classified into three categories: unmonitored, partially monitored, and fully monitored.

1.3 Maintenance is time-based and is also performed on the condition of the relay as determined by test personnel. For detailed information regarding Protection System Maintenance and testing, please refer to Protection System Testing Requirements in the SC&M Maintenance and Inspection Manual (MIM) for specific details.

1.4 Trip Testing may be performed to a knife switch or to the circuit breaker. Trip Testing to the circuit breaker must be performed at least once per relay routine cycle. Trip Testing to the circuit breaker will always be done when performing routine maintenance on the CB's LBFB relay. If there is no LBFB relay associated with the CB, than Trip Testing must be performed by the associated Line/Bank relays (both primary and backup).

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MT3: Circuit Breaker and Switcher Maintenance

1.0 General

1.1 Proper maintenance and test of circuit breakers and switchers is essential to good system operations. Maintenance personnel shall have a thorough understanding of the apparatus under their care and be able to perform all of the routine tests, adjustments, repairs, and inspections as needed. All repairs and adjustments will be documented.

1.2 Maintenance is performed on the basis of the condition of the equipment as determined by maintenance personnel. A log and/or history card for each circuit breaker and switcher shall be kept in the equipment. The date and brief description of the work performed, tests made, and counter readings shall be entered in the log or on the history card. Diagnostic and equipment records shall be retained on file at the crews' work base. For detailed information regarding Circuit Breaker and Switcher maintenance, please refer to the Circuit Breaker Requirements within Section CB of the SC&M Maintenance and Inspection Manual (MIM).

1.3 SF_6 gas is the dielectric/interruption medium of choice in circuit breakers and switchers. For SF_6 gas management, day to day operations, and more detailed information, please refer to SF_6 Requirements within Section SF6, the Radiography inspection process within Section CB-8 - Paragraph 3.6: Internal Inspection, and CB-10 - Paragraph 3.8: SF6 Gas Section of the SC&M Maintenance and Inspection Manual (MIM).

1.4 This order is subject to change as diagnostic equipment and/or test data warrants.

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MT4: In-Service Testing of Substation Equipment

1.0 General

Relaying systems require proper connections from CTs and/or PTs in order to operate as designed. Due to the critical nature of relaying circuits, it is required that in-service tests be performed prior to releasing the disturbed CT and/or PT circuit along with its associated equipment for service.

Installation or replacing of station equipment, such as transformers, circuit breakers, potential transformers, and protective relays, requires an in-service test to be performed.

In-service tests verify that the proper connections exist between CTs and/or PTs and their associated relays.

SCE's long-standing practice of in-service testing is not considered to be a replacement of the primary and secondary injections tests, which Substation Test Technicians perform prior to the equipment being ready for energizing.

In-service testing is to be used as a final check of the integrity and correctness of the CT and/or PT circuit and the connected relaying systems, while being energized at rated voltage with acceptable values of current.

The process of taking in-service readings requires that the direction of the primary current flow be known, through the equipment under test. It may be required to alter the configuration of the station or connected system, such as opening adjacent lines, for the duration of the in-service tests in order to force load current to flow in a known direction.

When in-service testing is performed, an adequate ground return source is required for proper relaying of phase-to-ground faults. Consult with the Protection Engineering department for requirements and recommendations.

2.0 Disturbed Circuit

A disturbed circuit is defined as damage to or an intentional lifting of a wire or wires within a protective relaying scheme, e.g., a relay replacement or lifting a wire to slide a donut CT for a DFR, removal of a device, repairing a damaged cable or circuit modification.

When a disturbance occurs, all disturbed devices will be declared "Not Ready for Service".

- In potential circuits: all devices where the potential has been interrupted by the disturbance will be considered disturbed.
- In series current circuits: all devices in the series circuit will be considered disturbed.
- In parallel current circuits (where currents are summed such as bus differential or summing point for line protection): all devices affected by the disturbance will be considered disturbed.

Note(s): There are some equipment that has pre-formed or keyed connections from the field equipment to the protective relay, such as GE UR Relay CT/VT modules, AR cannon type connectors, and electromechanical relays. Disconnecting and reconnecting these devices is not considered "disturbing" the circuit, however, tests will be performed to ensure shorting switches have been opened and/or proper connections have been re-established.

3.0 Energized First Time

All new primary equipment shall be protected by "Proven" protection when energized for the first time. Consult the Protection Engineering department for assistance in selecting the most desirable form of "Proven Protection".

4.0 Proven Protection

Proven protection is defined as a relaying circuit, composed of CTs and/or PTs connected to their associated relays which have been previously energized, tested, and in-serviced. Once a device is "Proven", it will remain "Proven" for its life until it is removed or replaced. In many cases "Proven Protection" is required to protect new station equipment during installation. Consult the Protection Engineering department for assistance in selecting the most desirable form of "Proven Protection" when in-service testing is to be performed.

If the circuit for a "Proven" protective relay is disturbed the effected relay(s)/function shall be considered "Not Ready for Service" until the appropriate testing is performed by the Test Technician. For exceptions, see Section 6.0 Exception for In-service Test Requirements.

See below for special requirements by Transmission, Sub-transmission and Distribution voltage level:

4.1 Transmission Applications

A. "Proven Protection" is required during the entire process to energize, test and in-service test the equipment for the first time at substations operating at Transmission voltage levels.

B. When CT and/or PT secondary circuits have been disturbed to in-service protective relaying equipment, in-service testing is required using "Proven Protection". Primary and/or secondary injection may be used to declare CT and/or PT circuits previously declared "Not Ready for Service" due to circuit disturbance, as "Ready for Service".

C. When in-service testing is required, the preferred work practice is to use line or equipment charging current to in-service test the new or disturbed station equipment. If line or equipment charging current is not adequate, then the alternative work practice of using isolated capacitors can be used if there are surge arresters installed on the isolated station equipment being used for in-service testing.

D. The voltage rise of 500 kV and 220 kV shunt capacitors can result in unacceptable high voltages on isolated lines and buses. Due to this voltage rise it is "NOT" recommended to perform in-service tests using this equipment unless a proper load study is done.

E. EXCEPTION: If reconfiguring the transmission system to provide in-service readings with "Proven Protection" requires a system configuration that may cause system instability, unacceptable voltages, or overloads for the next contingency, in-service testing may be performed with new relays that have not been "Proven" but have been made automatic. This exception will only be considered for extreme circumstances and requires the approval of GCC, System Protection and Test Management.

4.2 Sub-transmission Applications

A. Installation or replacing of station equipment, such as transformers, circuit breakers, and protective relays, require in-service test to be performed. "Proven Protection" is required to energize the new equipment for the first time. However, "Proven Protection" is not required when performing in-service testing. Station equipment, once energized, can be returned to service to perform in-service testing. Once the station equipment has been returned to service, the necessary in-service tests will need to be conducted as soon as possible.

B. When in-service testing of line or bus equipment is required, the preferred work practice is to use line or equipment charging current to in-service test the new or disturbed station equipment. If line or equipment charging current is not adequate, then the alternative work practice is to return the equipment to normal and in-service test using station load. Isolated shunt capacitors should "ONLY" be used as a last option to provide load current.

C. When in-service testing of bank equipment is required, the preferred work practice is to use isolated shunt capacitors to in-service test new station equipment if surge arresters are installed on both sides of the capacitor switching device. If shunt capacitors are not available, normal station load can be used for in-service testing. It is important to maintain an adequate ground return source during in-service testing. Consult with the Protection Engineering department for requirements and recommendations.

D. While performing the in-service test, if anything unusual is detected, the piece of equipment must be immediately de-energized, and will not be returned to service until further off-line testing and/or analysis has identified the cause for the unusual in-service readings.

4.3 Distribution Applications

A. Installation or replacing of station equipment, such as transformers, circuit breakers, and protective relays, require in-service tests to be performed.

Note(s): (Refer to section TR "Internal Fault Detectors (IFDs)" of the MIM to verify status of SL&P transformers during installation)

B. "Proven Protection" is not required when performing in-service testing on equipment operating at distribution voltage levels. When in-service testing is required, the preferred work practice is to use station load to in-service new station equipment. If this is a new station and load has not been connected, in-service testing must wait until load is brought into the station or a temporary load bank is provided.

C. Isolated shunt capacitor load can also be used for in-service testing if surge arresters are installed on both sides of the capacitor switching device. Caution should be exercised if the capacitor switching device is a vacuum device, due to their tendency to restrike which can result in excessive over-voltages when switching capacitors. It is recommended if vacuum devices are to be used for in-service testing to check with Transformation & Switching Engineering.

5.0 Modifications/Repair of Protective Relays

The modifications or replacement of protective relays require in-service testing to be performed. "Proven Protection" is required during the entire process to energize, test and in-service test the equipment for the first time.

6.0 Exception for In-Service Test Requirements

6.1 With concurrence of the assigned Grid Operations Capital Integration (GOCI) Program Engineer, Protection Engineer and Test Technician, primary and/or secondary injection may be used to declare devices previously declared "Not Ready for Service", due to circuit disturbance, as "Ready for Service".

This will be done by primary or secondary current and/or voltage injection from undisturbed locations and verify beyond the disturbed location.

The Test Technician will identify the suitable undisturbed locations prior to disturbing the circuit. The current and/or voltage injection must be performed prior to disturbing the circuit and repeated after reestablishing a complete circuit to verify amplitude and phase angle and will be validated by two technicians.

Once the equipment is returned to normal operation the Test Technician will take in-service readings at the relay using the relays Man Machine Interface (MMI) or other test equipment or both at the next available opportunity.

If a prior primary or secondary current and/or voltage injection from undisturbed locations is not performed, all associated relays will remain "Not Ready for Service" and may not be used as "Proven" protection until In-Service tests are performed.

When changing CT ratios or CT secondary configuration from delta to wye or wye to delta all associated relays will remain "Not Ready for Service" until In-Service Tests are performed.

6.2 Relay Repairs

In-Service test requirements for relay repairs will be determined by local Test supervision and will be dependent on the impact the repair has on the functionality of the relay.

MT5: Washing Energized Insulators in Substations

1.0 General

Washing insulators "hot" has proved to be a simple and satisfactory means of preventing flashovers caused by insulator contamination. SCE's equipment has been thoroughly tested in service and has proved adequate for the job. Use only approved 3/4-inch hose with a minimum dielectric strength of 100 kV/ ft and a minimum burst strength of 5,000 psi. However, any job that presents a problem should be discussed with the manager or an appointed representative.

2.0 Washing Distance

2.1 Nozzles are to be 7/32 or 1/4-inch diameter. In order to wash energized insulators with complete safety, the minimum water pressure at the nozzle must be at least 400 psi and the nozzle should not at any time be in contact with grounded or any metal parts of the rack or fence or be closer to the insulators than the distance shown in Table below.

Washing Distance for Energized Insulators in Substations

Line Voltage (kV)	Distance (ft)
4	4
12	5
16	5
33	6
66	7
115	9
220	12

2.2 The 7/32-inch nozzle should be used where it will do the job. Less water will be used because about 30 percent more water will flow through a 1/4-inch nozzle than a 7/32-inch nozzle at equal pressure. Each wash truck is equipped with three 7/32-inch nozzles and one 1/4-inch nozzle. These are to be removed whenever the wash truck goes to the main garage for servicing to prevent the possibility of being interchanged with nozzles of larger diameter. The diameters of the nozzles are to be checked periodically to detect any size increase which might result from erosion.

3.0 Nozzle Pressure Test

Before each wash season, after pump has been repaired or replaced or whenever the pump or hoses are suspected of malfunctioning, the following test should be completed:

3.1 Remove 7/32-inch nozzle from the wash gun, install pressure gauge adapter, check nozzle for proper dimensions, and replace nozzle on adapter.

3.2 With pump running, note pump pressure and engine rpm. The pump pressure should be 600 to 800 psi and the engine rpm should be 1,100 to 1,300 rpm.

3.3 Operate the wash gun with nozzle pressure gauge and note the pressure. This will be approximately 500 psi and should be, in no case, less than 400 psi. Also note the pump pressure and engine rpm.

3.4 Operate the wash gun with the test gauge and one other gun (with a 7/32-inch nozzle) and note nozzle pressure, pump pressure, and engine rpm. Test pressure should be 400 psi or more.

3.5 In order to further check the pump condition, again operate both wash guns. In addition, operate the wash gun (with a 7/32-inch nozzle) on the boom. This should allow the pressure relief valve to be fully closed and the nozzle pressure should reflect the true condition of the pump. Note nozzle pressure, pump pressure, and engine rpm. Nozzle pressure should be below 400 psi; therefore, washing with three guns is not permitted.

3.6 Any time the nozzle pressure is below 400 psi with one or two gun operation, do not use the washer for hot washing and return the truck to the garage for repair and adjustment.

4.0 Water Resistance

4.1 Test each load of water (before each use) using the water resistance tester. This includes water from the supply source as well as any water remaining in the wash truck. The resistance of the water must not be less than 20,000 ohms per inch cube or the conductivity of not more than 20 microhmos per centimeter cube as measured with a water conductivity tester. It should be noted that the resistance of water decreases as its temperature rises. A chart in the tester box illustrates this graphically. For this reason, water standing in the hose long enough to warm up should be discharged before the washing starts. Likewise, the water in the tank should be tested even if taken from a source which previously tested good.

4.2 Observances of these specified washing distances and water resistances will limit the current flowing between the insulators and the nozzle below one milliampere. The dangerous current is above 30 milliamperes. Experience has shown that if a stream of water is inadvertently turned on a hot line that is so close that the current is above ten milliamperes, the continuity of the circuit will be automatically broken by the muscular reaction of the operator.

NOTE Whenever the current is strong enough to feel, the nozzle is too close — Back Off!

5.0 Grounding

The body of the truck is insulated from ground by the tires and can thus become a large capacitor. If the truck is not grounded, it is possible for it to build up to a dangerously high voltage. For this reason the truck must be grounded while washing is in progress. It is of utmost importance that no human contact be made with the truck to avoid establishing a parallel ground through a person's body.

6.0 Washing Procedures

The SCE Substation Hot Wash video is available to view on portal.

6.1 During the Tailboard

A. The lead will discuss washing strategy, where to start, where to finish, and what to avoid:

- Wash distances that pertain to the specific job site and other safety hazards.
- Station status.
- Placement of all crew members.
- Who will wash and who will pull hose and check?
- Wash pressures.
- Who will be the lead washer and who will follow?

B. It is critical in the tail board to discuss the specifics of the substations you will be washing.

C. Some insulators and bushings are coated with silicone grease in several locations. Do not wash greased insulators. In heavily contaminated locations with insulators and bushings coated within RTV type coating, it may be necessary to rinse the coating occasionally. Consult engineering for a recommendation.

D. Remember that conditions and situations vary widely among substations and that hot washing is safe to do based on equipment, its condition, and proper washing techniques.

E. Adequate fall protection consisting of a harness and lanyard are to be worn when working from a bucket. On some jobs, hot washing is made more challenging by the need to coordinate bucket truck movement as well as washing teams. The bucket should be used to wash transformer bushings whenever vision is obstructed from the ground. When the wash gun operators are working from an elevated position, the observer must use a bullhorn for communication.

F. Do not wash transmission facilities in major 500 kV substations without special permission from the substation supervisor.

G. Instructions for use and operation of the washer unit must be kept with the unit. Tests outlined in these instructions must be made before washing is started. Any changes found necessary in the method of operation of the wash equipment should first be referred to the manager or an appointed representative.

H. Maintain the water tester so it is always in good condition. If there is any reason to believe the tester is inaccurate, notify the manager or an appointed representative. Avoid splashing water on the tester. Keep it dry and clean. Frequent and accurate testing is the key to successful energized washing.

I. If there any concerns about flashovers during a hot wash, consider hot wiping (using a live-line tool) it first.

J. A thorough prewash inspection site, tail board and proper wash techniques are critical to a safe and incident free wash.

K. Always follow all APM, SOM, and MIM policies and procedures.

6.2 Washer Operator & Pulling Hose (Observer)

A. Upon arriving at the substation, the acting operator and checker will notify the switching center, make an entry in the logbook, and check the substation status.

B. Inside the substation, perform the standard inspection for switching. Then inspect the substation for broken or damaged equipment and other safety problems that could cause a problem while washing.

C. Hazards to look for include broken or cracked insulators or bushings, birds' nest, kite strings, or other foreign objects that may cause a flashover. Excessive contamination, loose signs and normally open disconnects. If there are any questionable conditions, stop and immediately notify your supervisor.

D. Remove the entire hose from the reel before pressurizing. Operate the washer at a pressure of approximately 800 psi. This produces a compact stream of water which will do a better job of washing than a spray and reduce the possibility of flashover.

E. The wash gun operator should ensure that the line is securely attached to the wash gun while charging is in progress.

F. The wash gun operators and observers get into position to wash opposite sides of the insulators at an angle of about 120 degrees. To maintain this angle, it will be necessary to reposition yourself during the wash.

G. The observers must be able to clearly communicate with the wash gun operators to call their attention to an Arcing insulator or to point out what may flare up.

H. The observers need to stay close enough to the washers to guide them and keep them from falling when stepping backward or moving between equipment or racks. The observers have three main functions, (1) to warn of flare ups and (2) to keep the hoses in position so the wash stream works properly and (3) to keep the washers from tripping or injuring themselves on hazards while washing.

I. Just before washing, the lead person will check the prevailing wind once more and confirm the order of the wash.

J. Before starting the wash, be sure to flush out the hoses to release any hot water (due to sun heating hose) that has built up in the lines.

K. Washing should start at the end of the rack away from the prevailing wind so that any spray will drift onto cleaned insulators.

L. The lead washer begins washing and the second washer follows. Treating the wash gun as a loaded firearm, the barrel is to be always pointed down except when in use.

M. Both work in tandem with the lead washer communicating the next move.

N. During the wash, care needs to be taken to maintain a minimum safe wash distance. Exercise caution while moving in or around still structures and while walking near tripping hazards or over cable trenches.

O. Note that the hose and the roller are pinch points, therefore care should be taken while rolling up the hose to avoid injury.

P. When there is any doubt or question about conditions, immediately stop and notify your supervisor.

6.3 Washing Technique

A. When washing dead-end and vertical insulators that support conductors above, start with the unit furthest from the conductors. Wash succeeding insulators from the bottom up.

B. In general, washing should be done from the bottom up so that dirt will not be washed down over dirty insulators. It may be necessary to rewash the lower insulators while upper insulators are being washed. Finish by washing the lower insulators again. If insulator contamination is uniform, flashover is not as likely to occur.

C. When loose contamination is caused to flow by washing or being rained on, a flashover is more likely. This problem is most serious on vertical insulators when the flow is in the same direction as the voltage gradient of the insulators. For this reason, take particular care when washing vertical station post type insulators.

D. When conductors are below on suspension strings and vertically mounted insulators, wash from the bottom up, starting with the unit nearest the conductor and working upward.

E. Horizontal unit should be washed from the rack toward the conductor.

F. With pin type insulators, start with the inside of the skirt nearest the pin and then wash successive skirts if any toward the conductor.

G. Backwashing is the process of washing insulators from the opposite direction after the main wash is completed. Backwashing is normally done as required by inspection or conditions. Normally one quick pass on each insulator is all that is needed to rinse off any contaminants that may have crept around to the opposite side of the insulator.

H. Use care when washing single blade disconnects which are normally open. There is enough pressure in the stream to operate them if applied in the right direction.

I. When washing energized bushings, two guns should be used simultaneously from opposite sides, which will keep the bushings evenly wet.

J. Note that a blue discharge may form around the insulator during washing and will continue until the heat of the leakage current evaporates the water. You will usually hear considerable buzzing as well. Both displays are harmless. But if wild buzzing continues for more than one minute after washing, it indicates the cleaning was incomplete. The insulators should be clean from another direct. If a yellow flame starts,

a power arc is forming, which you should knock out with a stream of water before it develops into a flashover. Be sure to re-wash the insulator on which the yellow flame started.

K. The film buildup or scum on insulators should be closely observed. Notice that the insulator seems to have less and less glaze, particularly after it has been lightly dusted or washed and allowed to dry in the air. This film is usually a uniform deposit of atmospheric pollutants plus residue from wash water and causes an increase in leakage current. The film should be removed periodically as dictated by past experience or when the glaze becomes very dull or cloudy.

L. When washing de-energized operating busses, it is advisable to open all line disconnects so that the circuit breaker bushings may be washed at the same time.

M. When washing de-energized insulators adjacent to energized insulators, only one gun should be used at a time so that spray is held to a minimum. The second gun should be held in readiness to extinguish any arc that may start.

N. Never wash energized pocket bushings.

O. Be careful not to wash dirt from overhead structures onto conductors in such a manner that the dirt flows over insulators or bushings.

P. Do not wash polymer insulators and bushings or composite PTS and CTS.

Q. Be careful with the stream around jumper loops and potential transformer leads. Both primary and secondary.

R. Cambric leads and tape cable terminals should never be placed under a direct high-pressure wash. Straight washing of these services should simulate rain.

S. Avoid shooting a direct stream on breathers and gasketed joints on transformers, switches, and bushings.

T. Exert special care to avoid damaging synthetic cable terminations.

U. Do not wash transmission facilities in major 500 kV substations without special permission from the substation supervisor.

V. Bushings and potheads shall be "hot cleaned" before hot washing if, in the judgment of the foreman, the appearance of the contamination is too great to wash or to withstand the overspray. Short creepage or impaired clearance distances should also be considered in making this decision. When washing energized buildings, two wash guns should be used simultaneously from approximately opposite sides to obtain even wetting. Follow on down the bushing with the water stream periodically when washing above the bushing.

7.0 Wash Truck Inspection

Before each use, the wash truck should be inspected following the guidelines in the substation operation and maintenance policies and procedures manual. The following checks must also be made:

7.1 Revolve aerial bucket 360 degrees and check for any malfunction of the hydraulic system. Be sure that hydraulic hoses rotate properly. Check the boom operation from both sets of controls.

7.2 Fully extend the boom horizontally to the side of the truck. Operate the emergency “kill” button and wait until the engine stops. Operate the boom controls to determine that the check valves hold. The boom should not move in any direction. Start the engine and return the bucket boom to the rest saddle.

7.3 While the boom is fully extended, check the boom guide rollers for free operation and inspect the underside of the boom for any stress points.

7.4 Check the oil level in the pump gear box or reservoir.

7.5 Check hydraulic fluid reservoir level. A low oil level probably indicates a leak in the system. Check for any signs.

7.6 Inspect all hoses for wear or weak spots.

7.7 Log any unusual conditions in the truck log book. Complete the check sheet and sign it each day before the truck is to be used.

7.8 The person operating the wash truck should be sure there is sufficient water in the wash truck tank to finish the job once it is started.

7.9 The wash trucks should be parked in a position that allows the hoses to extend as much as possible to all washing positions. The crew will unroll the hoses completely, place them at the first washer area and attached the wash guns.

7.10 Truck placement is dependent upon station layout and wind direction.

7.11 Make sure that the wash gun operators are ready before opening the valves or starting the pump.

7.12 The operators will check the water pressure and when they have the go ahead, slowly charge the hoses. Normal water pressure at the pump is 600 to 800 psi. Minimum water pressure at the wash gun nozzle is 400 psi.

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MT6: Use of Approved Alternate Ductor Method (ADM) for Micro-Ohm Testing in Substations

1.0 General

1.1 The primary purpose of Micro-ohm testing (Ductoring) is to obtain diagnostic information to determine the main internal connection condition for circuit breakers. The procedure is performed on properly de-energized equipment that has been issued a clearance in accordance with the APM standard. The information and procedures in this document will enable employees to perform their duties safely and will ensure that ADM Micro-ohm Testing is performed in a safe consistent manner.

1.2 This procedure is in addition to policies, procedures, and rules set forth in other Company documents with which all employees are expected to comply.

1.3 The ADM was developed to improve the circuit breaker micro-ohm testing process. This procedure is for ductoring circuit breakers only.

1.4 Safety of personnel is of the utmost importance. This procedure is intended to assist in properly performing the Alternate Ductor Method. It is essential that the proper clearances have been issued before performing the Alternate Ductor Method; Reference APM Rule 404. Adherence to rules and the ADM procedure is required.

1.5 A Qualified Checker shall be utilized in accordance with APM Rule 408.

1.6 No person shall climb onto the circuit breaker without properly grounding in accordance with APM 141 and as outlined in the Substation Grounding Manual.

1.7 The use and care of live line tools (hot sticks) shall be in accordance with applicable APM rules. The ADM leads shall be inspected for functional integrity before testing.

1.8 The ADM 2/0 cable clamp shall be cleaned, adjust, micro-ohmed annually and logged with current practices.

1.9 Before beginning any ADM procedure, the supervisor or employee in charge shall hold a tailboard briefing in accordance with APM Rule P-20. The tailboard shall include these additional points:

A. The status of all issued clearances.

B. The location(s) to which the ADM testing leads are to be applied.

C. Requirement to verify that the line or equipment is de-energized before performing the ADM procedure.

D. Where the working hazard would be increased by the application of the ADM test leads, alternative methods should be considered by the supervisor to complete Micro-Ohm testing.

E. If there is any confusion regarding the ADM procedure at the completion of the tailboard, the supervisor or employee in charge will use the STOP Method; Stop, Think, Observe, Perform. This may include contacting your supervisor or SES.

2.0 Blocking CT Protection prior to ADM Testing

2.1 All personnel that will perform ADM testing are to be familiar with the requirements for blocking secondary switches (CT, rotos).

2.2 Failure to operate secondary switches of equipment to be ADM tested may result in the interruption of the load or circuit.

3.0 ADM Micro-Ohm Testing

The following procedure is the accepted sequence for proper utilization of the ADM:

3.1 Preparation of ADM

A. The supervisor or employee in charge shall hold a tailboard briefing in accordance with APM Rule P-20.

B. Determine the status of equipment and obtain a clearance.

C. Roll out all necessary CT roto's.

D. Set up ADM Test Set

1. Attach ground to ADM test box.

2. Connect current and voltage test leads to the ADM test box.

3. Apply voltage/current All Angle Clamp connector leads to the hot line tools.

4. Verify in line voltage/current leads are open to the ADM test box.

E. Clean substation ground grid conductor at the location where the ground clamps will be applied. Attach ADM 2/0 test cable duckbill clamp to clean station ground grid.

3.2 Testing

A. Utilizing checker, use hot line tester to verify equipment de-energized at the location where the ADM all angle clamps will be applied.

B. Utilizing checker, use hot stick to install ADM “all angle” clamps to both sides of circuit breaker.

C. Close the circuit breaker.

D. ADM test set will beep three times after successful reading and locks in test results. If test is successful, proceed to Step 3.2(E). If probe is required see “Probe procedure” below.

E. Un-plug all test voltage/probe in line connections. Record readings.

F. With checker, using hot-stick remove ADM all angle clamps from circuit breaker.

G. Repeat ADM testing procedure on next phase starting at Step 3.2(A).

3.3 Probe Procedure

A. Connect probe to hot stick.

B. Un-plug voltage lead in-line connector and insert in-line probe connector.

C. Utilizing checker and using probe mounted onto hot stick, pierce below the “all angle” clamp which starts the automatic ramp-up of the ADM test set. (May require probing other side for comparison)

D. ADM test set will beep three times after successful reading and locks in test results.

E. Un-plug all test voltage/probe in line connections. Record readings.

F. With checker, using hot-stick remove ADM all angle clamps from circuit breaker.

G. Repeat ADM testing procedure on next phase starting at Step 3.2(A).

4.0 Procedure for the Care and Maintenance of ADM Equipment

Well-maintained cables and clamps are essential for proper operation and safety of personnel. A visual inspection shall be done before each use as follows:

4.1 Clamp inspection — Check the overall condition of the clamp to ensure that is not damaged.

4.2 Cable and in-line connectors — Ensure cables and connectors are clean and free from damage.

4.3 Inspection/Cleaning of Hot Sticks — Thoroughly inspect poles for splintering, cracking, chipping flaking and missing end caps. Hot stick shall be cleaned as required.

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MT7: Use of Approved Portable Grounds in Grounding New or Out of Service Lines

1.0 General

1.1 The purpose of this order is to supplement *Accident Prevention Manual* (APM), Rule 141, which describes grounding of lines and equipment. Refer to Rule 713 and 714, under the Switching and Clearance Rules Section, for review of the terms “out-of-service” and “in-service.”

1.2 When new lines or out-of-service lines or transmission or distribution voltages are terminated at a substation and are not yet released for switching center jurisdiction, they must be grounded. The grounding of these lines will be the responsibility of the supervisor in charge and will be done under their supervision. Only approved portable grounds of 2/0 copper or larger shall be used for this purpose and they shall be grounded to either the steel structure or the substation ground grid network.

2.0 Continuity of Grounds

2.1 It is of paramount importance that the continuity of these applied grounds be maintained at all times. Once applied, these grounds must remain intact until the line or lines are released for switching center jurisdiction. If for any reason these grounds must be moved or relocated to complete the work, additional grounds or jumpers must be connected prior to such movement or relocation to ensure the continuing integrity of the applied ground.

2.2 When work has been completed, the lines will be released in accordance with APM, Rule 709 and System Operating Bulletin 25.

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MT8: Cubicle Switchgear Policies and Procedures

1.0 General

The maintenance and testing of cubicle switchgear presents unique challenges for personnel working with these types of equipment. Safety should be the first and foremost concern wherever this type of equipment is encountered. Due to the nature of this type of work, the following procedures shall be adhered to:

1.1 Clearances:

Clearances shall be taken on all rack out, draw out types of circuit breakers with no exceptions.

1.2 Electrical Checkers:

1.3 Electrical checkers will be required whenever work is to be accomplished inside of any cubicle bay regardless of configuration. This includes any secondary work such as cleaning contacts, working on space heaters, etc. Any primary work composed of phasing (Test Department), cable work (Cable crew) will also require an electrical checker.

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MT9: Environmental Standards Oil Spill Cleanup Procedural Guideline

1.0 General

The cleanup of soil contaminated with mineral oil from electrical equipment, especially large spills from ruptures, must be consistent and in accordance with corporate policies and procedures. This guideline is provided to assist local personnel in effecting a cleanup that ensures compliance with internal and external requirements. The confinement of spilled mineral oil on SCE property greatly reduces the exposure to public and regulatory intervention. The prompt response to a spill condition and required notification of local, state, and federal regulatory agencies, will directly affect the overall cleanup and closure process.

2.0 Containment

Confining the mineral oil to SCE property should be a priority. Spills beyond our control that reach public property may impact the reporting and subsequent cleanup efforts due to regulatory intervention by federal, state, county, and local agencies.

2.1 Oil absorbent materials, and tools for effecting control of flowing mineral oil, should be readily available and located in an area or areas with easy access to employees. All site employees should be familiar with the location of the materials and understand their responsibility in the proper use of these items during an emergency.

2.2 The identification of potential flow patterns and routes of release to offsite property is imperative. Where possible, steps should be taken to block or detour the route and contain the oil within the station. The placement of absorbent material(s) for emergency use near potential drains may be an option where blocking or diversion is impractical.

3.0 Identification of Containment

Spills of mineral oil from electrical equipment must be clearly identified for content of polychlorinated biphenyls (PCB) in parts per million (ppm). This will be of major concern during spills that involve regulatory agencies, especially if third party or public exposure is a factor. The regulatory level for liquid material being considered as a hazardous material is 5 ppm of PCB. The PCB level in solid material (soil) will affect the method of disposal but is not normally an immediate concern to the regulatory agencies.

3.1 Identify the PCB level with existing maintenance records if available. If outside agencies are involved, they will require copies of these documents.

3.2 If no documentation is available on PCB content, a PCB test kit should be used to satisfy immediate concerns.

3.3 An oil sample must be gathered and delivered to the Shop Services Instrumentation Division (SSID) laboratory in Westminster for analysis. Results are normally available via fax within one hour if advanced notice is given that the sample is enroute and it is communicated that results are needed as soon as possible. It is recommended that sample analysis be done regardless of existing records; however, the existing record may satisfy any immediate concern and the sample can be sent within normal time frames.

4.0 Liquid Cleanup

Where possible, all pooling or contained liquid mineral oil should be pumped, scooped, or somehow gathered to prevent absorption or penetration into soil surfaces. The Material Transport Division, located in Irwindale, has pumper-tankers that can be summoned for this purpose. Additional outside agencies may be in closer proximity and can be secured through Material Transport at PAX 48647 or 48649.

4.1 Concentrate efforts on low areas and hard surfaces where oil may accumulate.

4.2 Inspect cable trenches, pull boxes, and other locations for pooling of liquid material.

4.3 If possible, divert or direct the flow of oil into areas allowing the collection, and recovery of as much liquid as possible.

5.0 In-Service Equipment Cleanup

The flow of oil through a station can contaminate equipment and cabling causing serious damage and eventual problems.

5.1 Inspect cable in trenches for oil contamination and potential deterioration. The absorption of mineral oil into rubber jacketed cable causes eventual swelling and splitting of the covering and potential serious problems to station operation. It is suggested that the cable crew foreman be contacted to inspect and advise on necessary cable cleaning requirements.

5.2 Inspect locations where oil may reach sump pumps and block all automatic features to prevent further release of material. Many pumps are intentionally piped to direct water flow offsite into public drains and have the potential for greatly impacting cleanup efforts.

6.0 Contaminated Soil Removal

6.1 The timely removal of contaminated soil will greatly affect the overall cleanup. The longer the oil remains on and in the soil, the larger the cleanup will be. Dependent on soil condition, one gallon of mineral oil can contaminate as much as five tons or five cubic yards of soil beyond the acceptable level.

A. The corporate standard for cleanup of oil-contaminated soil is to achieve a total petroleum hydrocarbon (TPH) level of less than 1,000 ppm. This standard applies to spills contained on SCE property that may or may not involve regulatory agencies. Spills that contaminate public or third-party property, and possibly spills on SCE-only property that involve regulatory agencies, can result in having to achieve TPH levels as low as 100 ppm.

B. All visibly contaminated soil should be removed as quickly as possible. Soil may be placed in an open, accessible area and stockpiled on plastic to prevent further contamination. The rental of licensed and permitted roll-off bins is an alternative to stockpiling on plastic.

C. Once all visible contamination is removed, the open excavation should be diagrammed on a plot plan. Soil samples are taken for analysis to assure TPH levels below the established ppm limit. Sample locations are selected based on local management's judgment to achieve desired results that will ensure a complete and approved cleanup. Regulatory agencies, if involved, may dictate sample locations and do split-sample analysis of their own. Typically, samples should be at the lowest points of the excavation and spaced to represent an overall view of the cleanup. The analysis results become part of the spill/cleanup file.

Backfill of the excavation cannot commence until acceptable ppm levels are achieved.

6.2 This guideline is intended for use in the cleanup of significant amounts of mineral oil. It may be utilized for any amount spilled at the discretion of local supervision. However, immediate cleanup of significant amounts will normally nullify any need for soil analysis.

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MT10: Above-Ground Petroleum Tank Inspections

1.0 General

The Code of Federal Regulations (CFR), 40 CFR, Part 112.7 (e)(D)(iv) states, "Above-ground tanks should be subject to periodic integrity testing taking into account tank design (floating roof, and so forth) and using such techniques as hydrostatic testing, visual inspection, or a system of non-destructive shell thickness testing..." This order was established utilizing the criteria for tank inspections found in the American Petroleum Institute (API), Standard 653, Section 4 — Inspection, for the inspection of all above-ground, fixed oil tanks to meet 40 CFR requirements.

2.0 Tank Inspection

The external and internal inspection of substation oil storage tanks, by qualified inspectors, will be conducted at prescribed intervals to prevent the unexpected release of stored petroleum products into the environment.

3.0 Qualified Inspector

The qualified inspector shall be a registered professional engineer (PE), licensed by the state where the inspection is performed. In accordance with API 653, 4.10, qualified inspectors will perform the required external and internal inspections of oil storage tanks to comply with the tank integrity requirements of 40 CFR.

4.0 Frequency of Inspections

4.1 Several factors are considered to determine necessary inspection intervals for oil storage tanks. These include, but are not limited to:

- The nature of the product stored
- The amount (precent full) stored on a regular basis
- Changes in operating mode (frequency of fill/cycling)
- Potential risk of water pollution
- History of tank failures

4.2 A visual inspection shall be performed by a qualified inspector (as defined in API 653, 4.10) at the following intervals:

- External inspection — five year interval
- Internal inspection — ten year interval

5.0 Inspection Process and Procedures

Prior to scheduling an external or internal inspection of an oil storage tank, the following preparations shall be completed:

5.1 External — Five Year Interval

- A minimum of five feet clearance shall be provided from all relocatable objects to ensure access and visibility during inspection.
- Tanks shall be clearly marked with maximum allowable capacity and total content amount shall be easily recognizable.
- Past inspection records, if available, shall be present for review.

5.2 Internal — Ten Year Interval

- The tank shall be emptied of all possible material to allow safe movement within the tank and clear view of internal wall surface.
- Appropriate safety devices and personal protective equipment shall be available for use during the internal inspection.
- All applicable APM rules for working within confined spaces shall be adhered to before and during the inspection.
- Tanks without access for required internal inspection shall be tested for wall thickness, using applicable and approved methods, recognized by industry standards, to meet 40 CFR requirements.
- Tanks shall be clearly marked with maximum allowable capacity and total content amount shall be easily recognizable.
- Past inspection records, if available, shall be present for review.

6.0 Records

Inspection records form the basis of a scheduled inspection/maintenance program. The owner/operator of an above-ground petroleum storage tank must maintain a complete record file consisting of three types of records:

6.1 Tank construction records (maintained in SCE engineering files/archives)

6.2 Tank inspection history (maintained at responsible regional office)

6.3 Tank repair alteration history (if applicable, maintained in SCE engineering files and/or regional office)

MT11: Oil Handling — Administrative Policy for Control

1.0 General

The movement of insulating oil in substations is required to perform maintenance on electrical equipment. Many substation facilities have permanent oil storage tanks while others may utilize temporary storage including poly tanks, bladders, and mobile cargo tanker/trailers. The use of fixed above-ground and below-ground piping, pumps, portable hoses, and oil processing equipment is necessary to move the insulating oil to and from the electrical equipment. Extreme care shall be taken to reduce the potential for accidental discharge of oil into the environment.

2.0 Responsibility

Only qualified personnel have the authority to perform functions associated with oil handling, including connecting, disconnecting, opening, and closing of all temporary and permanent devices used in the movement of oil products.

3.0 Knowledge

Each qualified employee assigned the responsibility for oil handling shall:

- Understand his/her role in the personal assignment.
- Be prepared to recognize and respond to conditions relating to an unexpected discharge of oil during handling.
- Be familiar with the components of the station equipment and devices and prepare to effect a shutdown of the oil-handling process if necessary.

4.0 Control

The employee in charge shall have the responsibility and authority for the following control measures:

- The visual inspection of the permanent or temporary tank or container to be used for storage of oil, fixed oil lines, valves and flanges, and all fixed or portable pumps and hoses used in the transfer operation
- The securing of all temporary hose connections to fixed or portable oil-handling equipment including piping, pumps, tanks, tanker/trailers, mobile processing trailers, and electrical equipment
- The opening and closing of all valving devices on tanks, piping, and equipment during the oil-handling process
- The visual inspection of all valving devices prior to disconnecting hoses and lines to ensure they are in the closed position
- The reinstallation of caps or plugs in equipment valves, tank, and pipe connections

5.0 Limited Access

Substations have controlled access to its facilities with closed and locked gates, security fencing with barbed wire, and warning signs on all sides at prescribed intervals.

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MT12: Technician's Test Condition Tag (TTCT)

1.0 General

The objective of this procedure is to identify the requirements for using the large (6.25" X 3.125") Technician's Test Condition Tag and the small (3.25" X 1.625") Technicians Test Condition Tag.

2.0 Definitions

The Technician's Test Condition Tag (TTCT) is a flagging tool used to identify specific control circuit's abnormal conditions longer than one working shift or when unexpected work interruptions occur.

3.0 Policy

3.1 Test Technicians are responsible for implementing the requirements of this procedure.

3.2 Substation personnel are responsible for contacting the specific individual owner of the TTCT or the Supervisor if a question arises on the impact of the abnormal condition to the operation of the specific equipment.

4.0 When is a TTCT Required

4.1 TTCT is required per SOM section C-2: Substation Cable Trench Secondary Cable Work.

4.2 When the following abnormal conditions listed in this section will be abnormal ***in excess* of one (1) working shift**. I.E., Routine relay work extending past a scheduled work day, Capital upgrade work over several days or weeks or abnormal status due to work interruptions. Follow logging requirements as required per section G-5 Substation Logs. Use appropriately sized tag for applicable situations.

A. Any protective relay knife switch is in an abnormal state during normal routine maintenance.

B. Any protective relay knife switch is in an abnormal state on "In Service" panels involving construction modifications. (i.e., specific bus diff trips open due to breaker not in service).

C. Any temporary secondary cable needs to remain energized to maintain functionality or operability pending scheduled or future planned work.

D. Any temporary jumper for a substation control circuit is utilized to maintain functionality or operability (i.e., Temporary DC jumpers during cut overs or alarm contacts bypassed).

E. Any specific secondary switch outside of the specific switching program must be maintained to ensure continued functionality or operability. (i.e. damaged CT roto).

5.0 Required Information on TTCT

At a minimum the TTCT should have the following information:

- Date the abnormal status was created
- What device is in an abnormal state
- Abnormal condition (i.e., knife switch open, jumper installed)
- Contact name and number of individual responsible for abnormal condition

6.0 Removal of TTCT

6.1 When the abnormal status is no longer required, the TTCT shall be removed.

6.2 If the individual needing to restore the abnormal status is not the same individual who initiated the abnormal status, the Supervisor for the area of responsibility needs to be contacted to inform him/her of the pending restoration. The Technician may proceed after verification that restoration is approved.

7.0 Ordering

7.1 TTCTs can be obtained utilizing the SAP material numbers listed in Table 1.

Table 1: SAP Numbers for Technician's Test Condition Tag (TTCT)

Description	SAP Number
(6.25" X 3.125") "Technicians Test Condition"	SAP 10184696
(3.25" X 1.625") "Technicians Test Condition"	SAP 10184697

MT13: Alternate Push Method for pushing current through Current transformers on circuit breakers.

1.0 General

1.1 The primary purpose of Alternate push methods is to provide three alternate methods to grounding of all phases of a circuit breaker before pushing primary current. This procedure is in addition to policies, procedures, and rules set forth in other company documents with which all employees are expected to comply.

1.2 The Alternate Push Methods was developed to improvement from having to ground all three phases on both sides of the circuit breaker and having to lift the test leads up to the primary conductors on all CB's.

1.3 Safety of personnel is of the utmost importance. The testing de-energized and grounding of equipment should be a two person operation where practical. It is essential that the proper clearances have been issued before performing the Alternate Ductor Method; Reference APM Rule 404.

1.4 When required a Qualified Checker or Observer shall be utilized in accordance with APM Rule 408 and SOM SF-6.

1.5 No person shall climb onto the circuit breaker without properly grounding in accordance with APM 141 and as outlined in the Substation Grounding Manual.

1.6 The use and care of live line tools (hot sticks) shall be in accordance with applicable APM rules. Reference General Rule 104.

1.7 Before beginning any Alternate Push Method procedure, the supervisor or employee in charge shall hold a tailboard briefing per APM rule P-20. The tailboard shall include these additional points:

- The status of all issued clearances.
- The location(s) to which the alternate push method testing leads are to be applied.
- Requirements to verify that the line or equipment is de-energized before performing the Alternate Push Method procedure.
- If there is any confusion regarding the Alternate Push Method procedure of the tailboard, the supervisor or employee in charge will use the S.T.O.P. method. This may include contacting your supervisor or SES.

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Section C: Construction

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C1: Construction Projects — Roles and Responsibilities

1.0 General

1.1 This policy is intended to help clarify the Roles and Responsibilities of the Substation Test Technicians and Substation Electricians (Wiremen) during construction projects in order to perform work safely and effectively.

1.2 This policy is intended to address SCE Test Technicians, SCE Substation Electricians working as Wiremen, SCE CFF Electricians working as Wiremen, Contracted Test Technicians and Contracted Electricians working as Wiremen.

1.3 This policy is intended to address the use of a formal commissioning process for selected substation capital projects.

2.0 Print Review

2.1 Test Technician has the responsibility to review the prints prior to the start of the job to get familiar with the installation. This review should take place 2–4 weeks prior to the start of the work, and all corrections or changes shall be communicated as necessary.

2.2 Test Technician shall verify that all elementary drawings look correct and are per any applicable standards. All changes to elementary drawings shall be communicated to and approved from engineering.

2.3 Test Technician shall verify that all wiring diagrams look correct per the elementary drawings. All changes to wiring prints shall be communicated to Wiremen at pre-construction meeting.

2.4 Wiremen shall review prints one day prior to pre-construction meeting, earlier as needed for larger jobs, to get familiar with job and address any obvious issues.

3.0 Pre-Construction Meeting

3.1 Construction Supervisor/Maintenance Supervisor shall schedule meeting to include Operations, Test, Maintenance, CFF, and Contractors as needed.

3.2 Test Technician and Wiremen need to provide input during this meeting. Both will communicate any major print revisions to all parties including Operations and Engineering.

3.3 Test Technician and Wiremen both have the responsibility to communicate with each other all print revisions and verify that they are working on the most recent revision and corrected prints.

3.4 Construction Supervisor/Maintenance Supervisor shall bring to the meeting a general construction plan which will include job scope, sequence of work, and milestones.

3.5 Test Technician and Wiremen shall review and validate the general construction plan. All changes required will be communicated to the Supervisor holding the meeting.

3.6 Test Technician and Wiremen shall give input to schedule with regards to start dates. Depending on job scope, it is possible for the Wiremen to start prior to the Test Technicians moving on site. In these situations, it is important to communicate all print revisions.

3.7 Supervision shall address all environmental and hazardous material issues in the general construction plan. This shall be communicated to all parties at the meeting.

4.0 Job Start

4.1 Test Technician should create a more detailed plan that coordinates with the general construction plan. This plan will be communicated with the Wiremen, Contract Wiremen, and Supervision to make sure all are in agreement.

4.2 Test Technicians and Wiremen shall schedule periodic job status reviews communicating any changes in schedule, job status, and any potential issues that may create a delay, obstacle, or trap.

4.3 Wiremen shall verify that all material is received on site at the start of the job. Any shortages shall be listed and communicated to the Supervision or Site Rep to remedy.

4.4 Test Technician and Wiremen are responsible to communicate and address all safety issues found on the job site that were not previously addressed. All issues found shall be communicated to Supervision.

4.5 Test Technician and Wiremen should create a schedule with agreed upon milestones. It is important to STOP as needed (throughout the project) to document or review any unforeseen issues which will require updates to the schedule. All changes to the agreed upon schedule shall be communicated to Supervision as soon as possible.

4.6 Test Technician and Wiremen shall markup prints as necessary. All changes to prints shall be on-going throughout the job and will be done on the set of prints being maintained at the job site. All changes will be communicated between crafts. Contract Wiremen shall communicate all proposed changes to the Site Rep. Site Rep shall communicate these changes to the Test Technician.

4.7 Wiremen are responsible to pull, ring out, and identify all cables, and lay down and safe end prior to cutovers. Test Technician shall do this work only as a backup if required and practical. Test Technician shall Megger all current circuits. Wiremen “do not” currently Megger cables or circuits.

4.8 Wiremen shall verify with the Test Technician that the prints they are working from are the most recent revision and show all corrections. These prints should be review by the Test Technician and agreed as correct.

4.9 As work is being performed it is the responsibility of the Test Technician and Wiremen to verify correctness and accuracy of the work prior to leaving the position through self-check.

4.10 Test Technician and Wiremen shall check all circuits for shorts and grounds prior to energizing.

4.11 Prior to lifting or energizing any existing cable or wire on DC, current, potential or trip circuits, communication must take place between all parties affected (Maintenance, Test, CFF, and Contractors)

4.12 Wiremen shall not touch any in-service circuit without prior communication and concurrence from the Test Technician. Contract Wiremen shall not touch any in-service circuit without

communication and concurrence from the Site Rep. Site Rep shall communicate and get concurrence from the Test Technician.

4.13 Test Technician shall apply or verify proper labeling to all switches, cutouts, CT rotos and relays prior to the make-up of carrots in the pullbox, or connecting to in-service equipment/protection. Test Technician shall roll out ALL CT roto switches prior to the make-up of carrots on current cables. This labeling will be proven during testing of circuits and relays.

4.14 Test Technician shall apply relay settings per issued OD-43. All required changes to OD-43 will be communicated to Protection Engineering for approval.

4.15 Test Technicians shall test all relays to insure their correct operation.

5.0 Commissioning

5.1 Capital projects that utilize contracted resources to install and test new substation equipment will use the SC&M Commissioning Procedure. This process develops and executes consistent testing methods meeting business, technical, and regulatory requirements.

5.2 The TS&S Quality Assurance Commissioning Group is responsible for overall implementation and administration of the Commissioning Procedure.

5.3 The Project Manager or Construction Supervisor is responsible for implementation of construction, component testing and in-service testing sections of the Commissioning Procedure.

5.4 The TS&S Quality Assurance Commissioning Group is responsible for the system testing and feedback (lessons learned) sections of the Commissioning Procedure.

6.0 Pre-Cutover Meeting

6.1 Test Technician should develop a detailed in-service plan consistent with policy SOM MT4: In-Service Testing of Substation Equipment prior to the start of cutovers. The program, written from operations to in-service the new substation equipment, will be consistent with policy SOM MT4: In-Service Testing of Substation Equipment and any variations from this policy will require Protection Engineering to be consulted.

6.2 Test Technicians and Wiremen have the responsibility to arrange a meeting prior to cutover to review the in-service/cutover plan. This meeting is to provide a formal communication between work groups prior to the cutovers starting.

6.3 The in-service/cutover plan should include sequence of events and time frames based on the general construction plan and Test plan.

7.0 Cutover

7.1 Test Technician and Wiremen have the responsibility to execute the cutover plan as laid out and communicate all changes in a timely manner.

7.2 At the start of the cutover, the Test Technician and Wiremen shall conduct a tailboard regarding the scope of the cutover. This will include communications on cables to be landed, removed, or relocated.

A. All discrepancy found between what is on the print and actual wiring will require immediate communications between the Test Technician and Wiremen. The Test Technician will make the decision on how to best proceed and get proper approvals if required. All changes required will be reflected on the as-built print.

B. No Cables or wires shall be removed or laid down without prior communications between the Test Technician and Wiremen.

C. Once wiring is complete and prior to testing, a tailboard will be held between the Test Technician and Wiremen to verify all work has been performed as described in the pre-cutover tailboard. All changes that were made will be communicated and reflected on the as-built prints.

D. The Test Technician has the responsibility to prove all lifted or new current circuits by pushing primary/secondary current and verifying proper direction. All disturbed or new trip circuits require being tested from all actuating devices for verification of proper tripping.

E. The Test Technician has the responsibility of all in-service testing. During in-service testing a Wiremen shall be available for support or standby if needed.

8.0 Cutover Completed

8.1 Wiremen and Test Technicians will verify that all cables identified to be removed have in fact been removed. No cables shall be left lifted on one end only. Both ends of a cable shall be lifted and the cable removed if possible.

8.2 Test Technician and Wiremen have the responsibility to ensure that the final as-built prints are correct.

8.3 Test Technician, Site Rep, or Maintenance Supervisor has the responsibility to submit the final as-built print package to Engineering.

8.4 Test Technician and Wiremen have the responsibility to attend the post job meeting if necessary. All will communicate lessons learned to all attending.

8.5 Test Technician and Wiremen have the responsibility to fill out and submit a Design Assessment at the completion of the project.

C2: Substation Cable Trench Secondary Cable Work

1.0 General

1.1 Secondary cables that are improperly abandoned in cable trenches pose a shock risk to personnel and have been responsible for numerous cable trench fires.

1.2 This policy identifies how secondary cables, that physically can not be removed, are retired in place and the methods deemed acceptable.

1.3 This policy is in addition to procedures, work methods and rules set forth in other company documents which all employees are expected to comply with.

2.0 Responsibility

2.1 Compliance with this policy lies with all crafts. The responsibility for policy enforcement is of the Supervisors, Project Manager or their representative. SCE Test Technicians, SCE Substation Electricians, SCE CFF Electricians, Contract Test Technicians and Contracted Electricians working as Wiremen shall comply with this policy.

2.2 Requirements for secondary cable removal shall be covered in the pre-engineering meeting by the Responsible Engineer (RE) as outlined in EDSL 00-04-00, Section 8.1.B.

2.3 During the Pre-Construction Meeting (Job Walk) SOM C–1: Section 3.0, all secondary cable, for example, control, current, AC, and so forth, retirement work shall be identified per the cable retirement policy criteria SOM C–2: Section 3.0.

3.0 Policy

3.1 SCE craft and contract crews involved with secondary cable work shall have knowledge of the SCE cable retiring criteria and safe work practices for removing secondary cables from cable trenches.

3.2 Abandoning energized secondary cables in cable trenches is not allowed.

3.3 All retired secondary cable must be de-energized, disconnected and removed.

3.4 When complete removal is not physically possible, partial removal is permissible as outlined in SOM C–2: Section 3.5. Factors that may inhibit complete removal include:

A. Can cable be identified from end to end?

B. Is cable located at bottom of tray and anchored?

C. Is cable spiraled with other cables and difficult to pull?

D. Does cable enter a conduit with other in-service cables that could be affected by an attempted removal?

E. Do surrounding, in service, cables show sign of deterioration?

3.5 When the retired secondary cable can not be completely removed due to a physical obstruction, the cable must be cut and removed up to the point of physical obstruction.

A. Any de-energized and cut secondary cables shall be sealed with two half-lapped layers of green vinyl tape at the point of obstruction.

3.6 Secondary cables found abandoned and energized shall initially be identified and tagged per SOM C–2: Section 4.0.

A. Craft personnel shall notify their Supervisor, Project Manager or their representative of any abandoned cables to insure they are removed per this criterion.

3.7 When cable work requires a secondary cable be left energized pending scheduled or future planned work it shall be identified and labeled per SOM C–2: Section 4.0.

3.8 Salvaged secondary cables shall be removed from the cable trench or tray prior to cutting. This in an attempt to avoid the possibility of cutting the wrong cable and prevent incidental damage to adjacent secondary cables.

3.9 While working to install or remove secondary cables from cable trenches, walking on top of energized secondary cables should be avoided as much as possible.

3.10 Retired secondary cable ends shall be de-energized and sealed with two half-lapped layers of green vinyl tape.

4.0 Temporary Cable Identification

4.1 When cable work requires secondary cable to be left energized pending scheduled or future planned work it shall be safe-ended per SOM C–2: Section 5.0, and identified with an orange “Technician’s Test Condition” tag.

5.0 Safe-Ending Cables

5.1 Safe-ending secondary cables should be done in a fashion that insulates, isolates, and seals each individual conductor from accidental shorting and grounding. Refer to ECS 31-13-11 for more details and instruction.

5.2 Safe-ended secondary cables must be sealed by two half lapped layers of vinyl tape. Any color vinyl tape except green shall be used.

C3: Substation Capital Project Turnover Requirements

1.0 Objective

1.1 The development of the Substation Capital Project Turnover Requirements policy is to accomplish alignment between SC&M, Grid Operations, and Engineering when building, testing and placing new substation equipment in service. Lessons-learned sessions have identified the need for heightened communication and oversight from the beginning of construction to the final in-service testing phase of the project.

1.2 It is essential for all applicable groups to have confidence that all equipment has been designed, constructed, tested, and in-serviced to all applicable SCE standards, rules, specifications and policies. This policy will ensure that all parties agree that the substation or equipment is ready to be placed in service and turned over to Grid Operations.

2.0 Location of Procedure

2.1 The Substation Capital Project Turnover Requirements Procedure resides in the SCE Substation Construction and Maintenance (SC&M) Letters dated June 1, 2013.

1. The SC&M Letters can be accessed through the specified SC&M server.

3.0 Implementation

3.1 The Substation Capital Project Turnover Requirements are divided into four packages which consist of requirements, roles and responsibilities, and check sheets. The four packages are:

1. New Substations
2. Substation Expansions 66kV and above
3. Substation Expansions below 66kV
4. Infrastructure Replacement

3.2 The appropriate Turnover Package will be designated to each capital project.

3.3 The four separate turnover packages are managed by SC&M Construction and located on the SC&M Construction Project Managers Document Library.

4.0 Disposition Process

4.1 The Construction Project Manager (CPM) has the responsibility to approve and ensure that all applicable steps are completed in the Substation Capital Project Turnover Package. This includes Check Sheets and Turnover Forms.

4.2 The CPM will delegate the turnover package including check sheets and forms to the applicable assigned project initiator. The initiator in most cases is the SC&M Supervisor or Construction Planner.

4.3 Once construction starts on a project the entity that planned the project will handoff the turnover package and check sheets to the on-site project leader; which will be the SC&M Supervisor or the Construction Site Representative (CSR) for implementation and completion of Book 1 Construction.

4.4 When Book 1 Construction is completed the turnover package will be handed off to the Book 2 Component Testing & Book 3 In-Service Testing on-site leader which will be the applicable SC&M Supervisor, Start-up Engineer (SUE), or Contract Test Supervisor (CTS). The turnover package will be completed and approved by the applicable leader as stated and approved by the CPM.

4.5 Steps to a Successful Turnover Package

STEP 1. A Turnover Package is assigned to the responsible SC&M Supervisor or Construction Planner, whoever is planning the project.

STEP 2. The responsible SC&M Construction Supervisor or Construction Planner will extract the applicable electronic version of the Substation Capital Project Turnover Package from the SC&M Construction Project Manager Document Library.

STEP 3. The responsible SC&M Construction Supervisor or Construction Planner will hold a Pre-Construction Job Walk utilizing the Turnover check sheets.

STEP 4. The Planner facilitates a bid job walk (Contract projects).

STEP 5. The design quality review process is implemented on identified projects (Contract projects).

STEP 6. A Purchase Order is issued by procurement, approved by the CPM and Manager of Construction (Contract projects).

STEP 7. The Bid is awarded (Contract project).

STEP 8. On major projects, a contractor question and answer meeting is implemented (Contract projects).

STEP 9. On SC&M Construction projects, the Supervisor 3 will hand off the blue folder including the turnover package and check sheets to the SC&M Field Supervisor 2.

STEP 9.1 On SC&M Maintenance projects, the Construction Planner or SC&M Construction Supervisor will hand off the blue folder including the turnover package and check sheets to the SC&M Maintenance Supervisor.

STEP 9.2 On Contract projects, the Construction Planner hands off the blue folder including the turnover package and check sheets to the CSR for Book 1 Construction. If project does not include Book 1 Construction, such as example of relay replacements and SAS upgrades, the package containing the check sheets will be handed off from the planner directly to the SC&M Test Supervisor or CTS.

STEP 10. Book 1 Construction initiated.

STEP 11. The SC&M Construction Supervisor, or SC&M Maintenance Supervisor, or CSR will utilize the Turnover Check Sheets for Book 1.

NOTE Be aware that the Turnover Check Sheets are different than the Construction Quality Control Check Sheets.

STEP 12. The Book 1 Construction is complete.

STEP 13. SC&M Supervisor or CSR will facilitate a Book 1 Construction quality job walk using the turnover check sheets. A punch list of NCRs will be collected at the construction job walk and will require correction and closure before the pre-release turnover walk down.

STEP 13.1 CPM, CSR, SC&M Quality Control Inspector, SC&M Maintenance Supervisor or designee, Grid Operations Supervisor (SOS) or designee, and the Primary Contractor will attend and approve Construction turnovers. The SC&M Construction Supervisor on CSR will lead and facilitate this meeting and turnover walk down.

STEP 14. On projects the SC&M Supervisor will hand off the turnover package with the partially completed check sheets to the SC&M Test Supervisor or their representative, or if Contract Test project hand off the turnover package to the SUE if assigned, or to the CTS if SUE is not assigned.

STEP 15. Book 2.0 Component Testing is implemented on the apparatus and protective equipment.

STEP 16. Book 2.0 Component Testing, on the equipment in the switch rack, must be completed before moving forward to the next step.

STEP 17. CPM will ensure that training and or training materials are provided for all new equipment. CPM will delegate this task to the group with the expertise.

STEP 18. A pre-release of the equipment for substation jurisdiction turnover job walk will be implemented at this time. The inspection will entail paying particular attention to the apparatus equipment, construction, and testing of the apparatus equipment at the outside rack. This will include utilizing the turnover check sheets and forms. All abnormal status of the equipment being released will be documented on the turnover form, logged in the station log book, and be transmitted and communicated to the Switching Center, SC&M Test Supervisor, SC&M Maintenance Supervisor, SC&M Construction Supervisor if assigned, CPM, CSR, SUE if assigned, and the Contract Test Supervisor (CTS) if assigned.

STEP 18.1 CPM, SC&M Maintenance Supervisor, SC&M Test Supervisor, CSR if assigned, SC&M Construction Supervisor if assigned, SOS, SUE if assigned, and the Quality Control Inspector shall attend this job walk and approve the equipment turnover.

STEP 18.2 This meeting will be led and facilitated by the SC&M Test Supervisor on their projects, SUE if Contract Test and start-up project, or Contract Test Supervisor (CTS) if not a start-up project which involves Contract Test.

STEP 19. Release the equipment for Substation Jurisdiction using the Substation Capital Projects Turnover Requirements form in compliance with System Operating Bulletin (SOB) 25.

STEP 19.1 The person releasing new equipment for substation jurisdiction is responsible to ensure the release gets logged in the log book at unattended substations and reported to the jurisdictional switching center.

Even if another entity logs the release in the unattended substation log book it is still the responsibility of the person releasing the equipment to ensure it is logged correctly.

STEP 20. Take Clearances and connect the new equipment to existing equipment complying with SOB 132.

STEP 21. Book 2.0 Component Testing in the MEER building and all labeling must be complete before moving to the next step.

STEP 22. On Contract Test projects a Book 2.5 System or Functional test will be implemented, approved, and performed at this time in accordance with the Substation Capital Project Commissioning Procedure located in the SC&M Letters. If a functional test is required in lieu of a 2.5 System Test, the procedure for the Functional Test will be requested utilizing the Lotus Notes Outage Request Log (ORL). The Functional Test procedure will be submitted to the switching center. The switching center will incorporate the functional test procedure in the switching program.

STEP 23. SC&M Test Supervisor, SC&M Maintenance Supervisor, SUE (on Contract Test and startup projects), CTS (if Contract Test and not a start-up project) will implement a job walk before the new equipment is energized. The pre-energize job walk will be facilitated by the responsible SC&M Supervisor (Test, Maintenance, Construction) on internal projects and the responsible SUE or CPM or their representative on Contract projects. Inspection attention will be focused on the connection points where the new equipment is connected to the existing equipment at the outside rack, or any other completed construction that has not been inspected from the original construction and pre-release job walks. A quality inspection of the protective relays and relay racks, alarms, automation equipment, transformer LTC, and labeling in the MEER building will be performed at this time. This job walk will ensure that all apparatus protective equipment switches (both primary and secondary) are in the desired positions and ready to be energized. This will include utilizing the turnover check sheets and forms. The Grid Operations Switching Center will have verified that all alarms are accurate on the Energy Management System (EMS) before Book 2.0 Component Testing is approved.

STEP 23.1 The CPM, SC&M Maintenance Supervisor, SC&M Test Supervisor, SC&M Construction Supervisor (if assigned), Quality Control Inspector, SOS, SUE (if assigned), CSR, CTS (if assigned), Quality Assurance Commissioning (QAC) Supervisor or designee, and Contract Standard Station Instructions (SSI) group (if assigned), shall attend this job walk and approve the equipment turnover. The switching program will be checked for accuracy by the Substation Operations Supervisor (SOS), SC&M Test Supervisor or designee (if assigned), SUE (if assigned), and CTS (if assigned).

STEP 24. Book 3 In-Service Testing starts and is complete. All in-service test sheets are completed and approved by the SC&M Test Supervisor on their projects, SUE on Contract Test startup projects, and CTS on Contract Test non start-up projects.

STEP 25. A Final inspection job walk will be performed to ensure substation equipment is clean, installed properly, in proper working order, and meets all specifications outlined in this procedure.

STEP 25.1 The CPM, SC&M Maintenance Supervisor, SC&M Test Supervisor, SC&M Construction Supervisor if assigned, Quality Control Inspector, SOS, SUE if assigned, and CTS if assigned shall attend this job walk and approve the final station turnover.

STEP 25.2 The final inspection job walk will be facilitated by the SC&M Test Supervisor or designee on their projects, SUE on Contract Test start-up projects, and CTS on assigned projects that are not start-up.

STEP 26. SC&M Supervisor (Test, Maintenance, Construction), SUE if assigned, CTS if assigned and if not a start-up project, and CSR to ensure the Turnover Check Sheet and Forms are complete and turned over to the CPM for approval.

STEP 27. After the CPM's approval, he or she will submit the completed Turnover Package to the SUE or Start-up Engineer (if assigned), or the SC&M Contract Test Project Manager.

STEP 28. The SUE or the SC&M Contract Test Project Manager will place an electronic copy of the Turnover Package on the designated SCE server for future reference.

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Section E: Equipment

TABLE OF CONTENTS

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E1: Substation Equipment Designation Standards

1.0 General

It is essential that equipment designations be standardized in substations to simplify operating procedures and facilitate personnel training. The rules for marking and designating various substation equipment are as follows.

2.0 Sequence

Whichever of the following descriptions are necessary to distinguish a specific piece of equipment shall be used in the order given:

1. Name.
2. Geographical location.
3. Voltage.
4. Function.
5. Device.

Most station equipment can be specified by using several but not all of the above descriptive categories. However, the order shall remain the same (e.g., Corum 66 kV Line Disconnect or 12 kV Bus Paralleling CB).

3.0 Circuit Breaker (CB)

3.1 500 and 220 kV CBs will be numbered in accordance with System Operating Bulletin 84.

3.2 On voltages below 220 kV, the CB designation is to be stenciled on each side of the CB (e.g., Carmenita North 66 kV).

3.3 Ring bus configurations will have at least three, but no more than four CBs, the bus work cannot be defined by geographical direction. The CBs shall have a double number; such as, 22, 44, 77, and 88 which does not correspond with any voltage on the Edison system.

3.4 In substations with rack configurations that contain a single bus-tie circuit breaker, the bus-tie circuit breaker shall be designated as the "Bus Tie ___kV CB".

3.5 In substations in which there is more than one bus-tie circuit breaker, the name of the bus-tie circuit breaker shall include, in its name, the bus section to which it is associated. For example, if the bus-tie CB in question is tied to the A Section of a __kV bus, the CB shall be designated as the "A Section Bus Tie __kV CB". (Figure 16.)

3.6 Sectionalizing CBs shall have the same designation as the bus section of which they are a part of. Every sectionalizing CB with disconnects on each side is a bus section (Figure 6). Sectionalizing CBs without disconnects on each side shall be called the X-Y sectionalizing CB. The two letters used will identify which two sections of bus are connected by the CB.

3.7 Bus paralleling CBs will be designated by reference to the two busses they parallel.

3.8 At breaker-and-a-half switchracks the tie CB shall be designated by reference to the rack position it occupies (Figure 5).

3.9 CBs that may be switched from one line to another shall be named by reference to both circuits to which they may be attached (Figure 8).

3.10 All other CBs will be identified by reference to the equipment they control.

4.0 Disconnects

4.1 500 and 220 kV disconnects will be numbered in accordance with System Operating Bulletin 84.

4.2 Any disconnect that attaches a line or equipment to an operating bus will be designated as a bus disconnect, except banks that are connected to a bus through only one set of disconnects. These disconnects will be designated as to the circuit or bank to which they are connected (Figure 6).

4.3 Any disconnect that attaches a line or equipment to a transfer bus will be designated as a transfer bus disconnect.

4.4 A disconnect located between a CB and a circuit will be designated a line disconnect. This designation will apply to positions designed to include a CB even though the CB is not installed.

4.5 A disconnect located between a CB and the transformer(s) leads will be designated a bank disconnect (Figure 1).

4.6 A disconnect located between a bank disconnect and a transformer will be designated as an isolating disconnect (Figure 3 and 4).

4.7 Disconnects to a CB that are neither line, bank, bus, nor transfer bus disconnects will be designated as position disconnects (Figure 1 and 2).

4.8 Disconnects used to bypass other equipment will be designated as bypass disconnects. At a station having more than one bypass disconnect, each bypass disconnect will carry the name of the line or equipment of which it is a part (Figure 9, 10, and 14).

4.9 At customer-type stations the disconnects will be labeled as line disconnect, bank disconnect, and bypass disconnect (Figure 9).

4.10 At customer-type stations with a CB (Figure 11 and 12), the disconnects directly on the line side of the CB shall be labeled as line disconnects. Any other disconnects on the line side of these disconnects which are in series with the CB and line shall be labeled as station disconnects (Figure 12).

4.11 At customer-type stations with a CB, any disconnects on the customer side of the CB shall be labeled as follows: If the disconnects attach the CB directly to a bank located on Company property and operated by Edison personnel, the disconnects will be labeled bank disconnects (Figure 11). If the disconnects attach the CB to leads which go directly to customer equipment, the disconnects will be labeled customer disconnects (Figure 12).

4.12 An in-line disconnect that, when open, permits the position to be used as a bus tie will be designated a station disconnect.

4.13 At breaker-and-a-half switchracks the disconnects to the tie CB shall be labeled as the (circuit name or bank designation) tie No. XX _____kV (Line or Bank) disconnects (Figure 5).

4.14 A disconnect in series with any of the above-described disconnects shall take the name of the equipment which it isolates for purpose of clearances; e.g., station light and power disconnect (Figure 7).

4.15 Disconnects installed to transfer a CB from one line to another shall be named transfer line disconnects (Figure 8).

4.16 Disconnects used to parallel equipment will be named paralleling disconnects. (Figure 4).

5.0 Bus And Bus Sectionalizing Disconnects

5.1 Operating bus -- A bus which normally serves as a common point from which one or more circuits and/or banks radiate. Where two operating busses of the same voltage are in a station, they shall be distinguished by reference to their geographical relationship, such as North_____kV Bus.

5.2 Transfer bus -- A bus to which circuits or banks may be transferred through the bus tie or a position used as a bus tie.

5.3 Sectionalized busses -- They shall be lettered A, B, C, D, etc. Any equipment between or beyond a set of disconnects shall be considered as a bus section.

5.4 Sectionalizing disconnects -- They shall be called X-Y sectionalizing disconnect. The two letters used will identify which two sections of the bus are connected by these disconnects (Figure 1 and 6).

5.5 Inner-outer bus configurations -- Their configuration makes them appear to have a horseshoeshaped inner and outer bus. These busses will have an ultimate of several operating bus sections. This will provide for an inner bus and outer bus A, B, and C, etc., sections with sectionalizing disconnects and/or CBs (Figure 15).

5.6 All busses will have a proper marking for phase identification as well as equipment designation.

5.7 Unique situations that will not fit into any of these categories will have their nomenclature determined after consultation with the Manager of Substation Operations.

6.0 Transformer Banks

6.1 500/220 kV transformer banks will be designated with a number followed by the letters AA.

6.2 220/115 kV or 220/66 kV transformer banks will be designated by the number 1 through 4, respectively, followed by the letter A.

6.3 All distribution banks will be designated by number only and in transmission stations, distribution power banks will not use a number used by, or reserved for, A banks.

6.4 Condenser banks will be designated by a number followed by the letter C.

6.5 Back-to-back transformer banks shall be designated by a number and geographical location; such as, No. 1 Bank East Unit and No. 1 Bank West Unit.

6.6 Power transformers shall have the bank designation and voltage ratio stencilled on the tank and clearly visible from all sides of the bank.

7.0 Regulators

7.1 The circuit name, amp capacity, type, and percent regulation shall be stencilled on the tank of each three-phase regulator and on the center tank of a group of three single-phase regulators.

7.2 A compensator setting record card shall be prominently displayed on the inside of the control housing.

8.0 Capacitors

8.1 Capacitors will be designated No. 1, No. 2, and No. 3, consecutively whether or not they are connected to a common bus or common voltage.

8.2 The breaker and disconnect associated with a set of capacitors will be designated the same number as the capacitors (Figure 7).

8.3 Capacitors which are switched in sections will be designated as A, B, or C section; i.e., the capacitors energized by the No. 1 capacitor CB will be designated No. 1A Capacitor. The second step will be designated No. 1B Capacitor, etc. (Figure 7).

9.0 Switchboards

9.1 Control panels --Circuit breaker controls, knife switches, meters, meter jack positions, pilot lights, alarm sectionalizing devices, rheostat controls, supervisory cabinets, supervisory positions, and related equipment shall be labeled for ease of identification and to facilitate proper operation.

9.2 Indicating lights -- Indicating lights are to be colored red for close, green for open, and white for pilot.

9.3 Pushbuttons -- Auxiliary relay lockup release buttons will be surrounded with a three-inch solid yellow circle. Where buttons are used for circuit breaker controls, the closing button will be red and the opening button green. Pushbuttons will be marked to indicate the circuit breaker controlled.

9.4 Metering -- Bank ammeters will be marked to indicate the planned load capacity and N-1 capacity of the bank being metered. Line ammeters will be marked to indicate their minimum trip when this is a known figure. All recording meters will have their multiplier or constant labeled on the front of the instrument.

9.5 Relay Panels

A. Protective relays

1. Panel-mounted protective relays are to be identified from the front and back of the board by tapewriter labels or standard dispatch board adhesive lettering or other appropriate method. All switches external to the relay must be identified in like manner on the face of the board. Relay targets shall be outlined on the glass cover with a square white decal.
2. Relay and carrier cabinets will be identified on the front panel with standard dispatch board adhesive lettering or other appropriate method.

9.6 Roto Switches —- Roto switches, regardless of where they are mounted on the switchboard or in the equipment, will be marked with their function. The relays that are to be made solid before operating the roto switch shall be clearly stated. Roto switch travel limits are to be marked with white tape or paint.

10.0 Metalclad Switchgear

On metalclad or cubicle gear, each cubicle or position shall have the circuit name marked on the outside of all doors to that position and also on the panel inside. Disconnect switch controls shall be properly marked indicating which disconnect it controls and on which position. The means by which operations are performed shall be clearly indicated.

11.0 Pipelines and Gas Cylinders

11.1 Edison Company hydrogen cylinders shall be painted Safety and Piping Code Color No. 190 red (SAP 10062906) with a six-inch wide black band, the center of which shall be 36 inches from the bottom of the cylinder. “Property of S.C.E. _____ Sub., Hydrogen” shall be stencilled on the black band in white letters one-inch high.

11.2 Edison Company carbon dioxide cylinders shall be painted Safety and Piping Code Color No. 195 chrome green (SAP 10062903) with a six-inch wide black band, the center of which shall be 36 inches from the bottom of the cylinder. “Property of S.C.E. _____ Sub., Carbon Dioxide” shall be stenciled on the black band in white letters one-inch high.

11.3 Edison Company nitrogen cylinders shall be painted Safety and Piping Code Color No. 195 chrome green with a six-inch wide black band, the center of which shall be 36 inches from the bottom of the cylinder. “Property of S.C.E. _____ Sub., Nitrogen” shall be stenciled on the black band in white letters one-inch high.

11.4 Edison Company sulfur hexafluoride cylinders shall be painted Safety and Piping Code Color No. 195 chrome green with a six-inch wide black band, the center of which shall be 36 inches from the bottom of cylinder. “Property of S.C.E. _____ Sub., Sulfur Hexafluoride” shall be stenciled on the black band in white letters one-inch high.

11.5 Water lines except for fire hydrants, shall be painted the standard color for outdoor equipment or to blend with the aesthetic treatment of the station. Water lines to rotating machinery shall have arrows showing direction of flow.

11.6 Oil lines shall be painted black for a distance of at least six inches on each side of in-line valves. Where separate lines are used for dirty and clean oil, they shall be so stenciled. Oil lines to rotating machinery shall have arrows showing direction of flow.

11.7 Gas lines

A. Hydrogen lines shall be painted Safety and Piping Code 190 red (pressure gauge lines).

B. Carbon dioxide lines only shall be painted Safety and Piping Code Color No. 195 chromegreen. (Carbon dioxide feed lines used only for that purpose)

C. Multipurpose lines

1. Gas lines to the top of a condenser shell, which can be used both for hydrogen and carbon dioxide, shall be painted Safety and Piping Code Color No. 195 chrome green with a Safety and Piping Code Color No. 193 yellow (SAP 10062902) band one-inch wide at least every 12 inches.
2. Gas lines to the bottom of a condenser shell, which can be used for carbon dioxide and hydrogen, shall be painted Safety and Piping Code Color No. 195 chrome green with a Safety and Piping Code Color No. 190 red band one-inch wide at least every 12 inches.

11.8 Valves should be kept clean and tagged with metal tags designating the primary purpose of the valve. Aluminum strips as used for cable designations are acceptable. The valve stem and packing glan nut should not be painted.

Figure 1

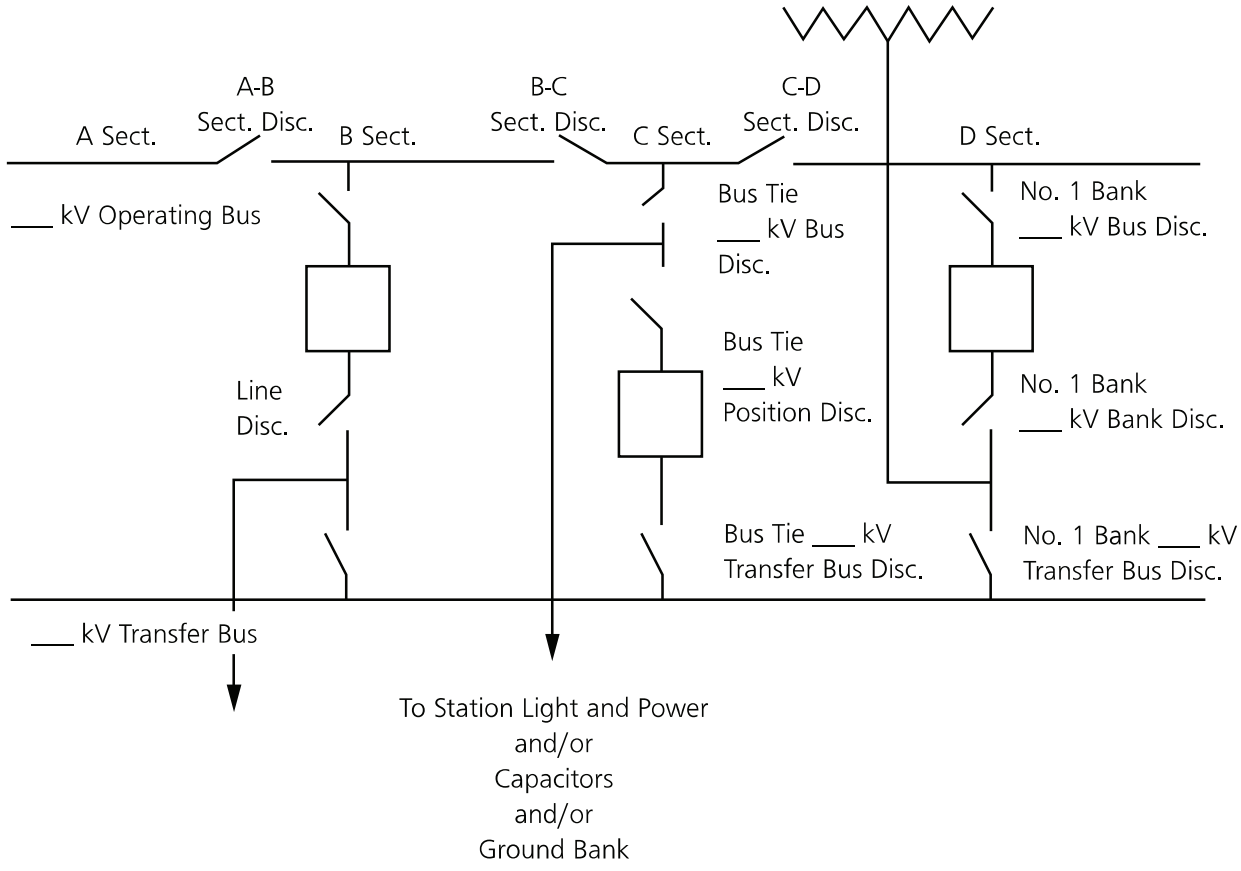


Figure 2

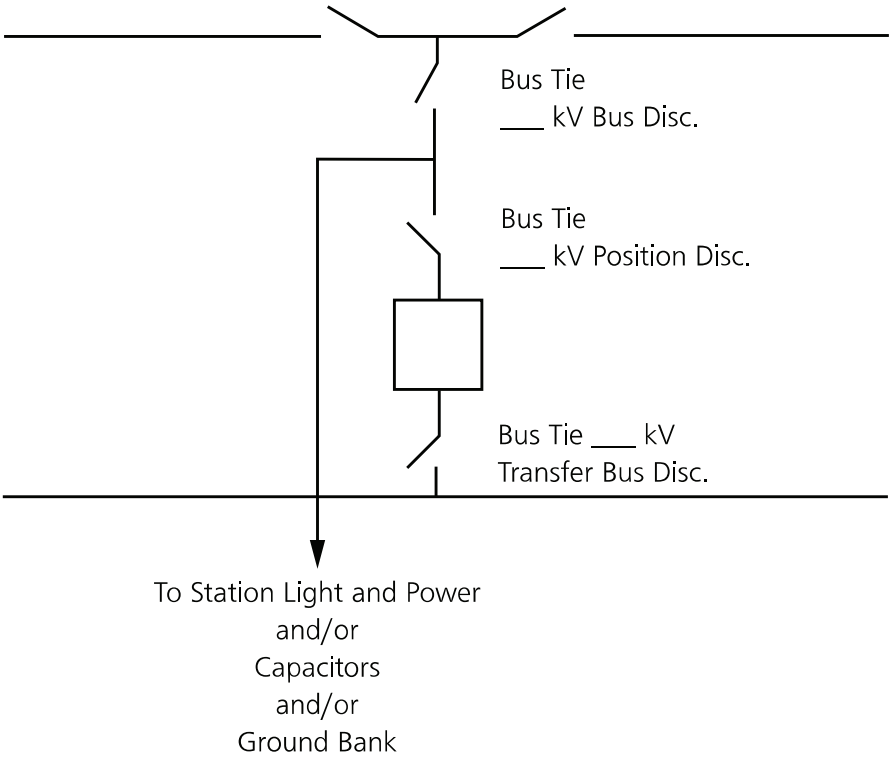

Bus Tie
___ kV Bus Disc.
Bus Tie
___ kV Position Disc.
Bus Tie ___ kV
Transfer Bus Disc.
To Station Light and Power
and/or
Capacitors
and/or
Ground Bank

Figure 3

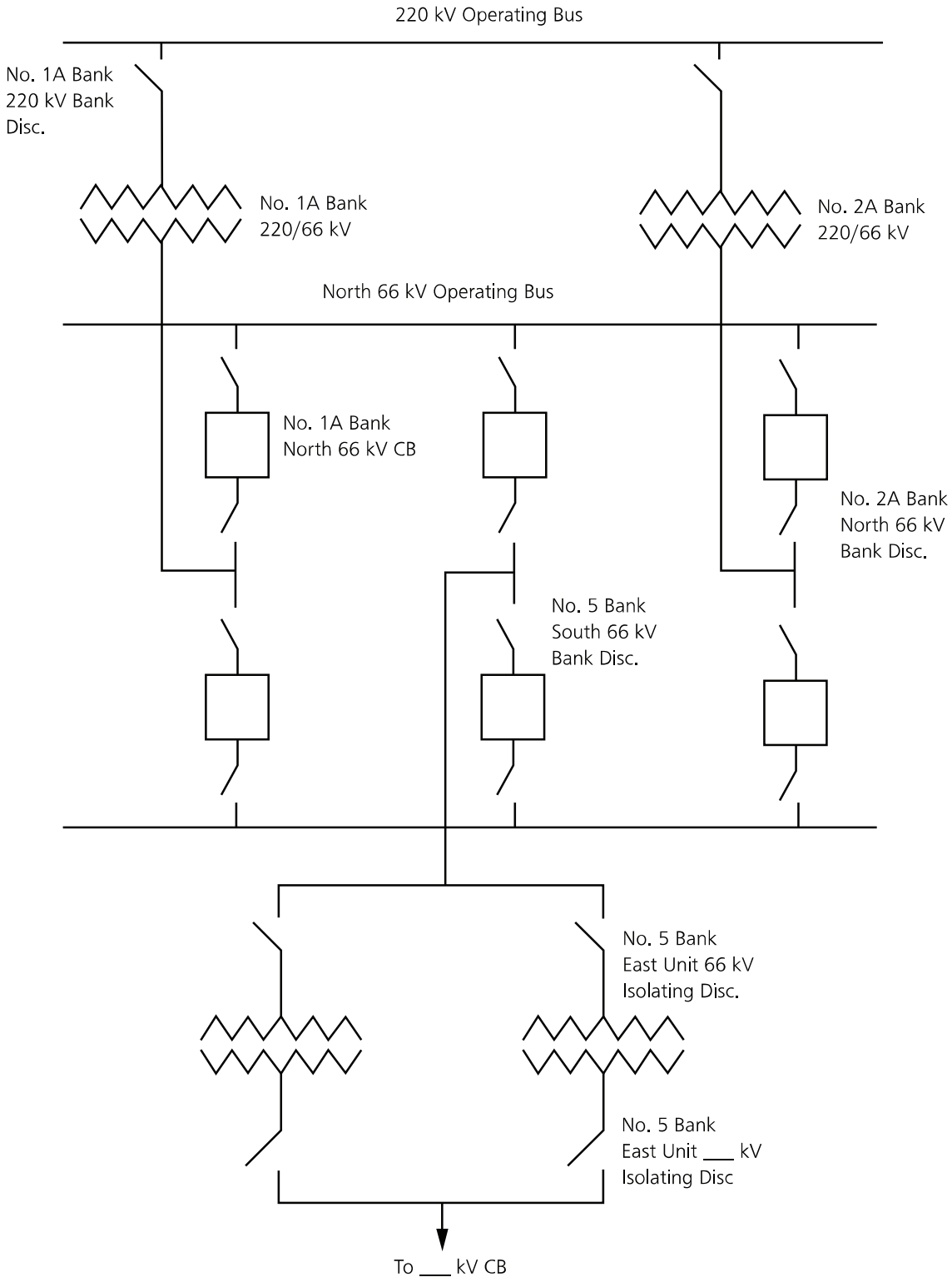

220 kV Operating Bus
No. 1A Bank
220 kV Bank
Disc.
No. 1A Bank
220/66 kV
No. 2A Bank
220/66 kV
North 66 kV Operating Bus
No. 1A Bank
North 66 kV CB
No. 2A Bank
North 66 kV
Bank Disc.
No. 5 Bank
South 66 kV
Bank Disc.
No. 5 Bank
East Unit 66 kV
Isolating Disc.
No. 5 Bank
East Unit ___ kV
Isolating Disc
To ___ kV CB

Figure 4

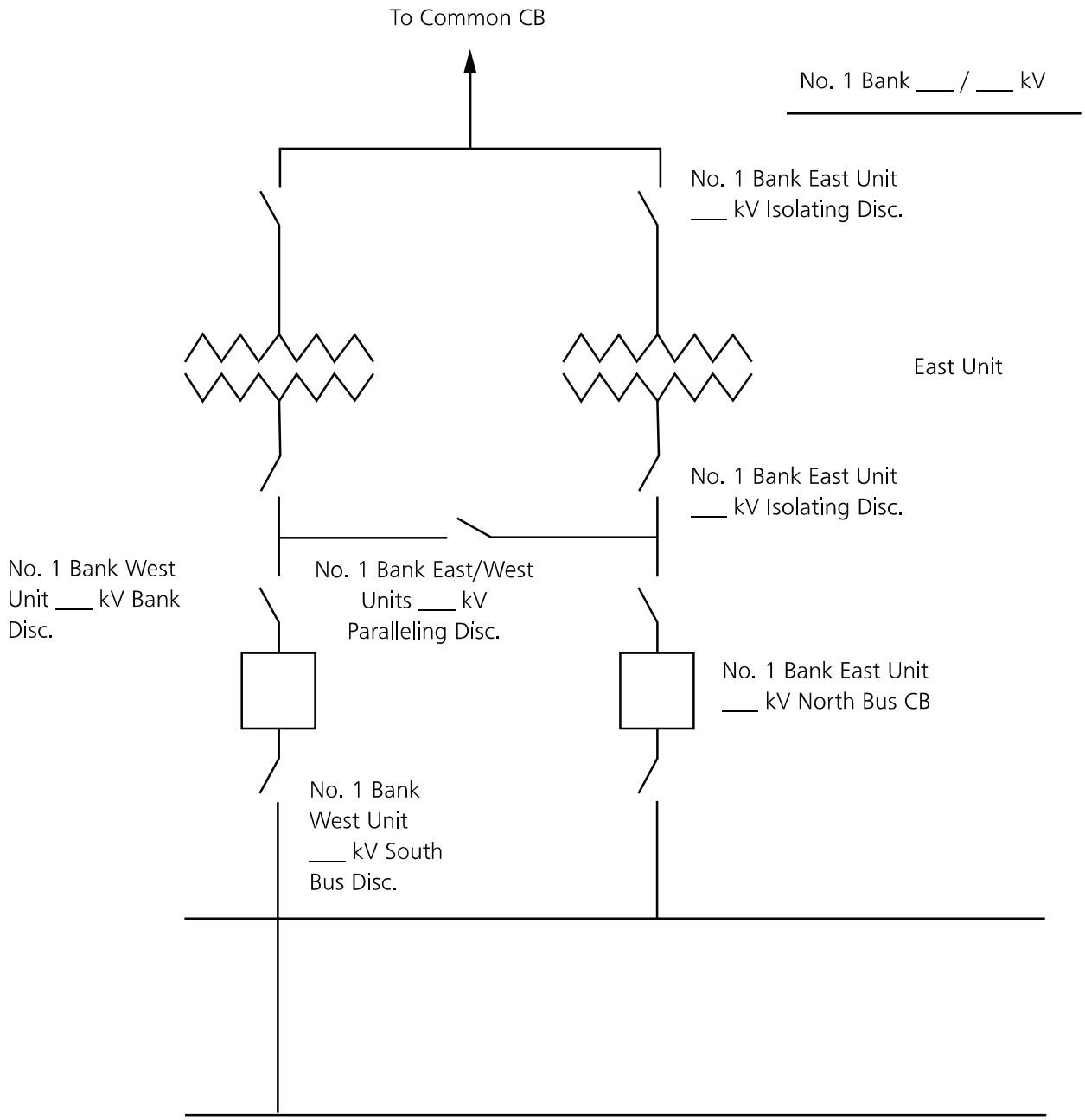

To Common CB
No. 1 Bank ___ / ___ kV
No. 1 Bank East Unit
___ kV Isolating Disc.
East Unit
No. 1 Bank East Unit
___ kV Isolating Disc.
No. 1 Bank West
Unit ___ kV Bank
Disc.
No. 1 Bank East/West
Units ___ kV
Paralleling Disc.
No. 1 Bank East Unit
___ kV North Bus CB
No. 1 Bank
West Unit
___ kV South
Bus Disc.

Figure 5

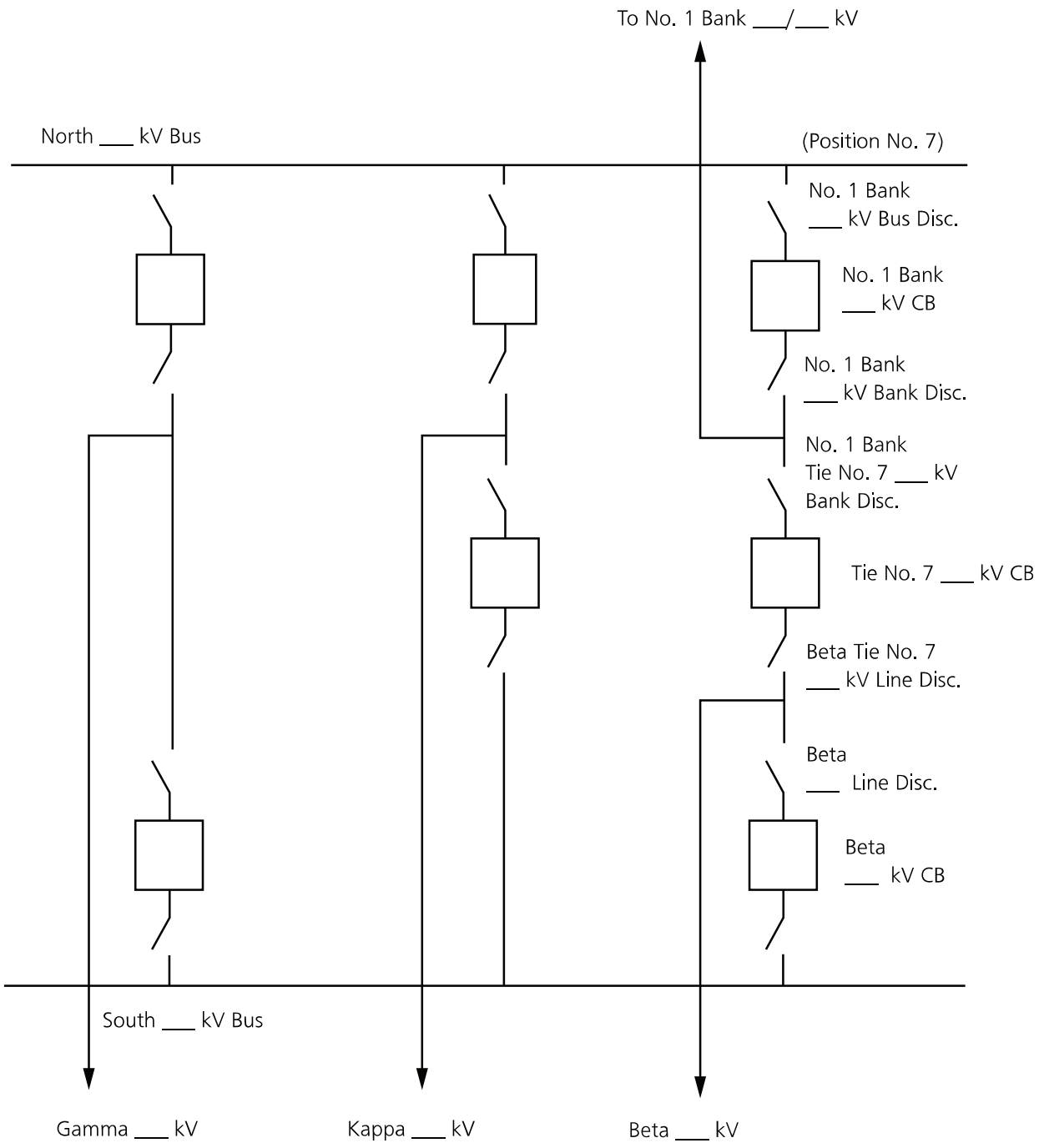

To No. 1 Bank ___/___ kV
North ___ kV Bus
(Position No. 7)
No. 1 Bank
___ kV Bus Disc.
No. 1 Bank
___ kV CB
No. 1 Bank
___ kV Bank Disc.
No. 1 Bank
Tie No. 7 ___ kV
Bank Disc.
Tie No. 7 ___ kV CB
Beta Tie No. 7
___ kV Line Disc.
Beta
___ Line Disc.
Beta
___ kV CB
South ___ kV Bus
Gamma ___ kV
Kappa ___ kV
Beta ___ kV

Figure 6

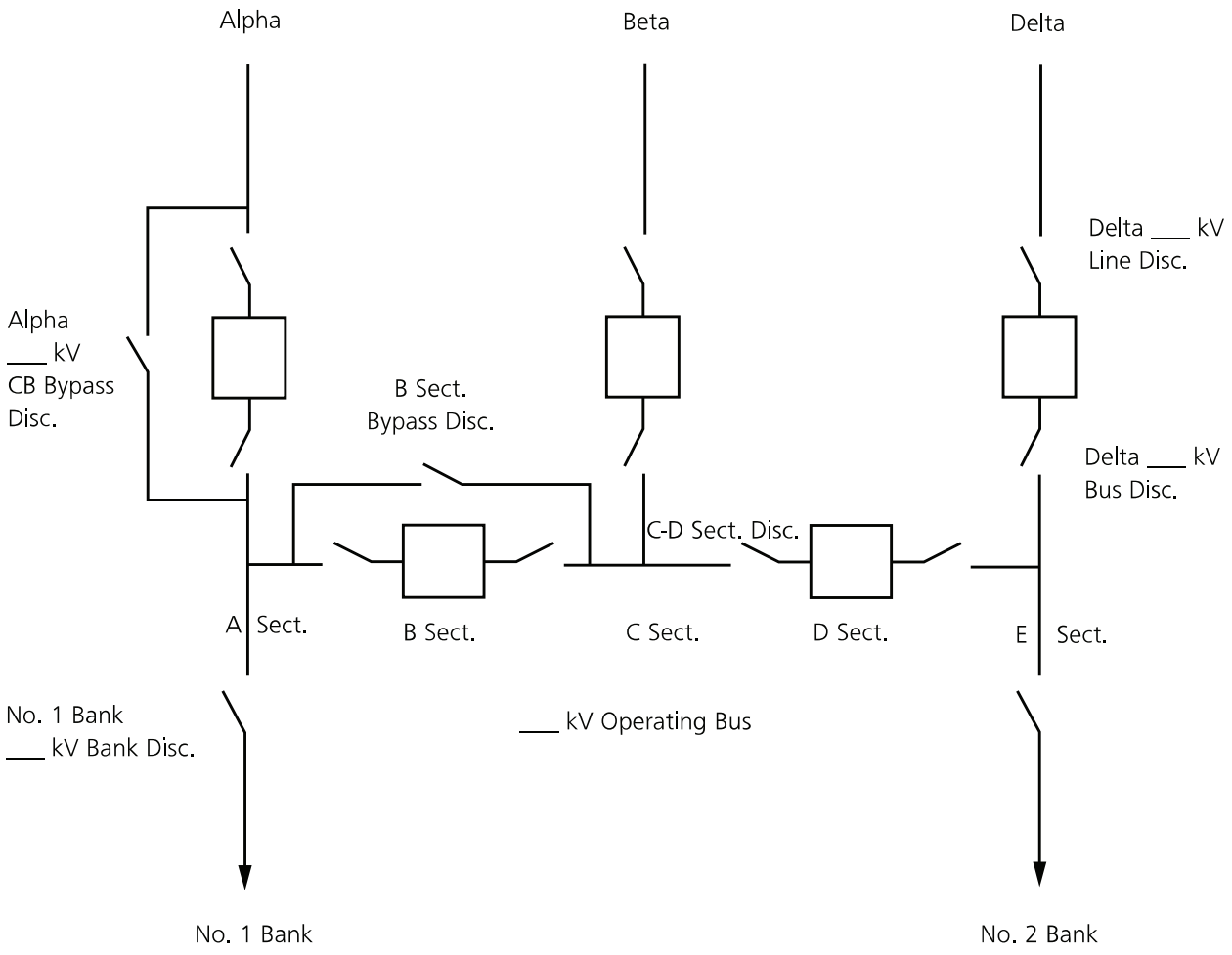

Alpha
Beta
Delta
Delta ___ kV
Line Disc.
Alpha
___ kV
CB Bypass
Disc.
B Sect.
Bypass Disc.
Delta ___ kV
Bus Disc.
C-D Sect. Disc.
A Sect.
B Sect.
C Sect.
D Sect.
E Sect.
No. 1 Bank
___ kV Bank Disc.
___ kV Operating Bus
No. 1 Bank
No. 2 Bank

Figure 7

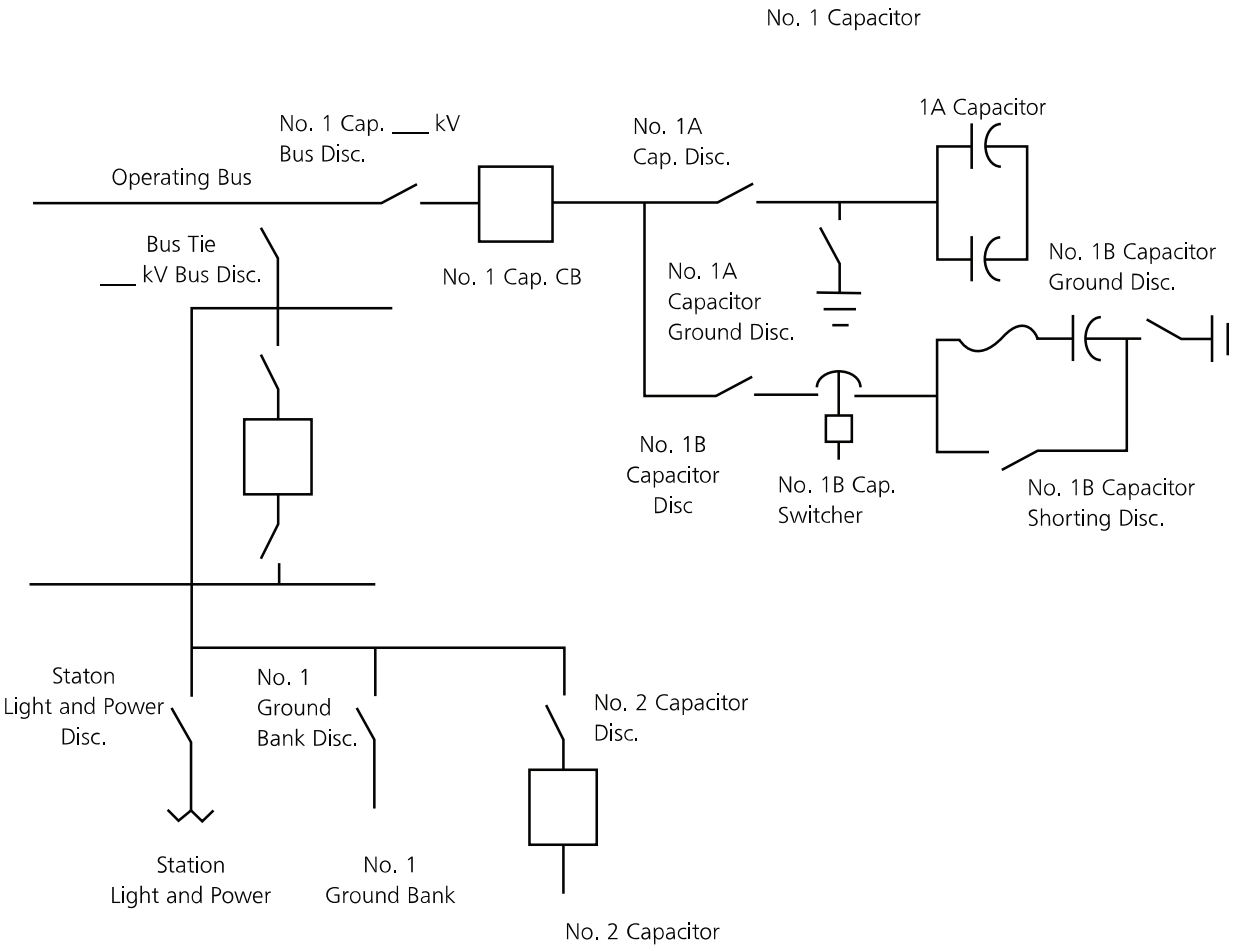

No. 1 Capacitor
No. 1 Cap. ___ kV
Bus Disc.
Operating Bus
No. 1A
Cap. Disc.
1A Capacitor
Bus Tie
___ kV Bus Disc.
No. 1 Cap. CB
No. 1A
Capacitor
Ground Disc.
No. 1B Capacitor
Ground Disc.
No. 1B
Capacitor
Disc
No. 1B Cap.
Switcher
No. 1B Capacitor
Shorting Disc.
Staton
Light and Power
Disc.
No. 1
Ground
Bank Disc.
No. 2 Capacitor
Disc.
Station
Light and Power
No. 1
Ground Bank
No. 2 Capacitor

Figure 8

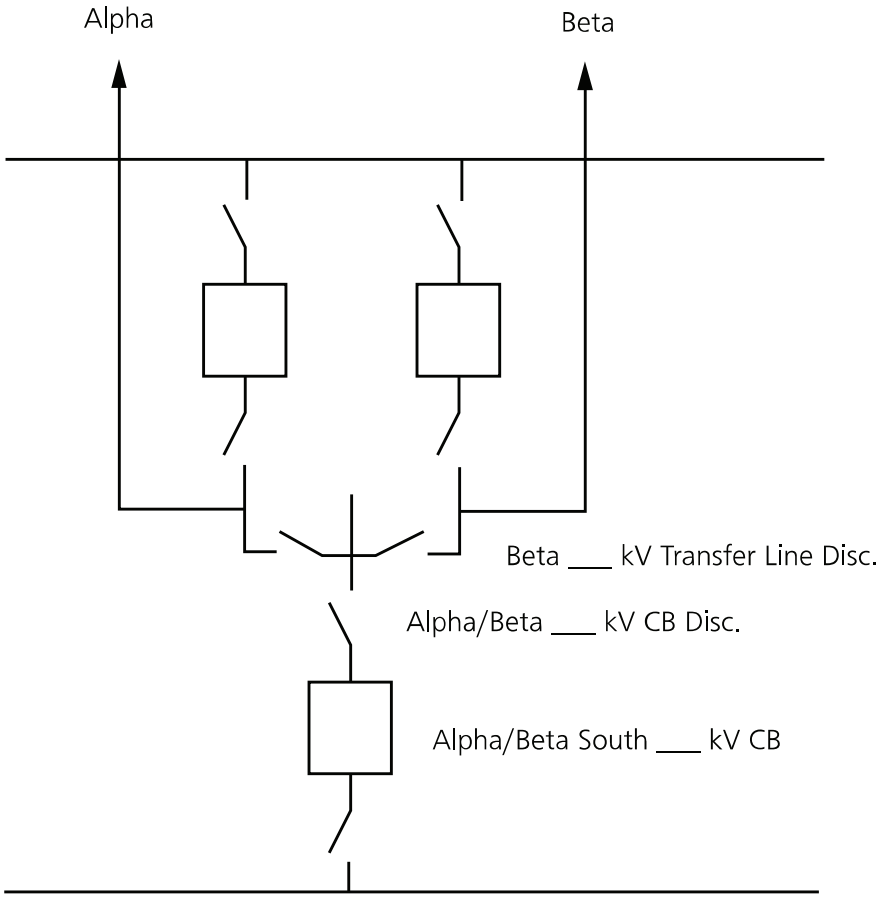

Alpha
Beta
Beta ___ kV Transfer Line Disc.
Alpha/Beta ___ kV CB Disc.
Alpha/Beta South ___ kV CB

Figure 9

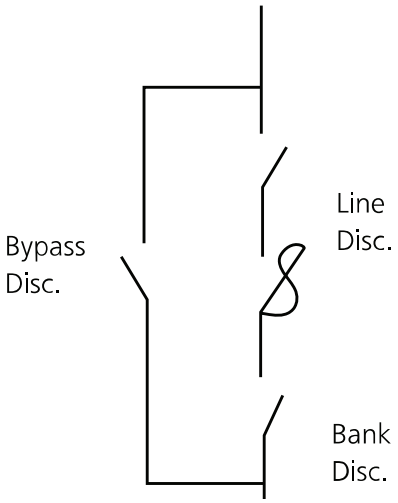


Figure 10

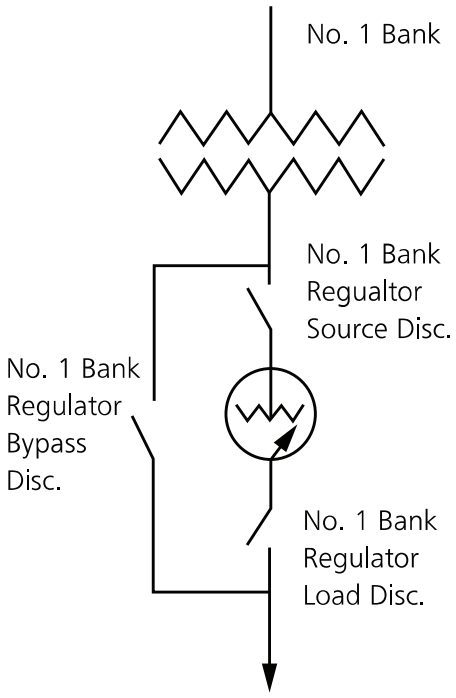


Figure 11

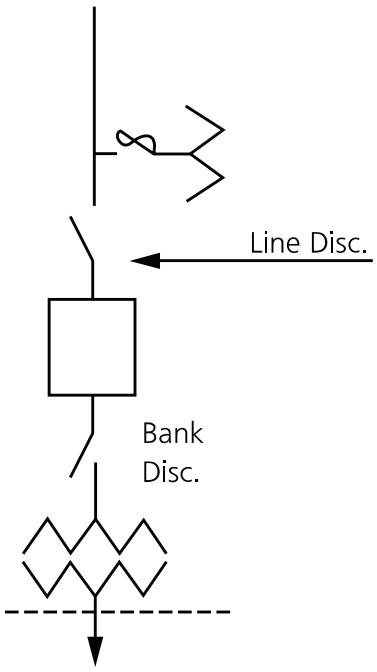


Figure 12

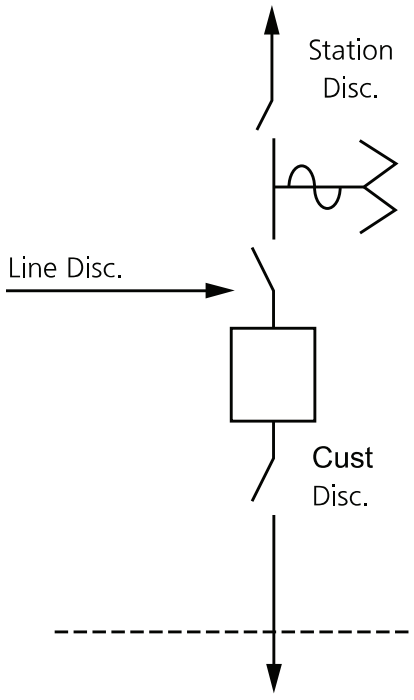


Figure 13

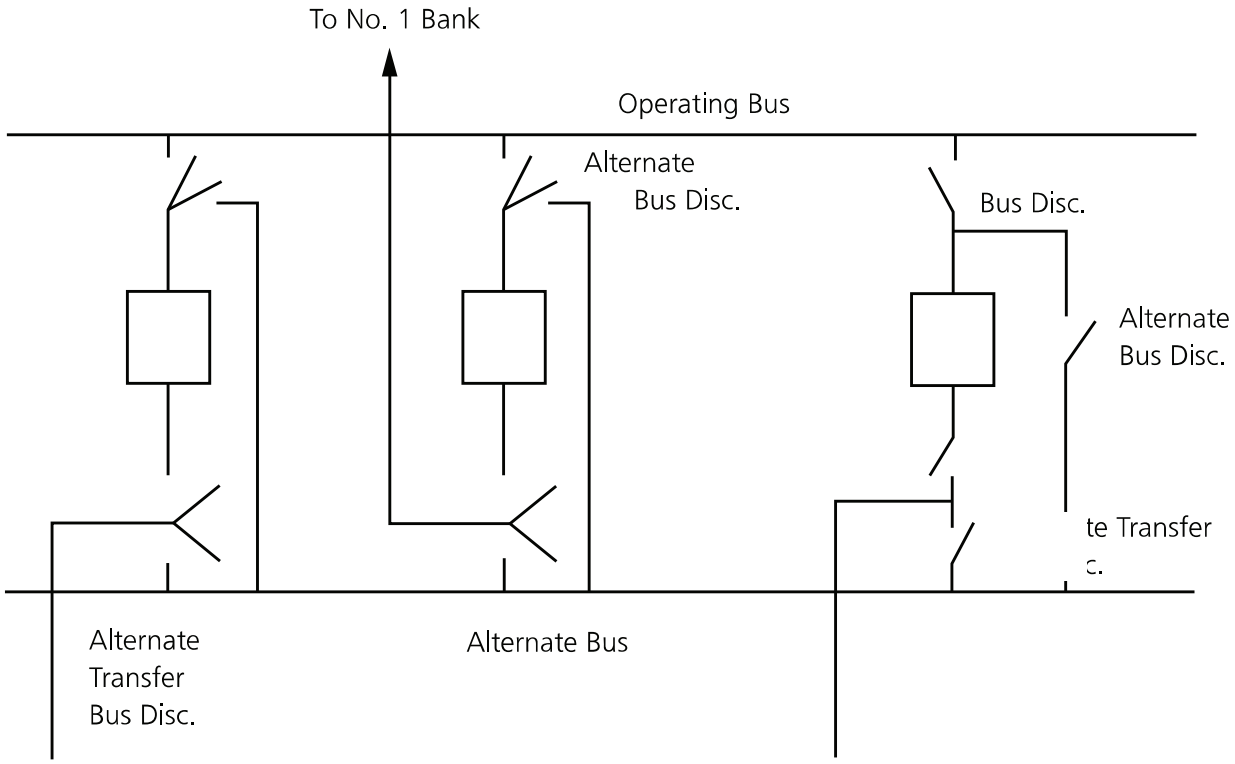

To No. 1 Bank
Operating Bus
Alternate
Bus Disc.
Bus Disc.
Alternate
Bus Disc.
te Transfer
c.
Alternate
Transfer
Bus Disc.
Alternate Bus

Figure 14

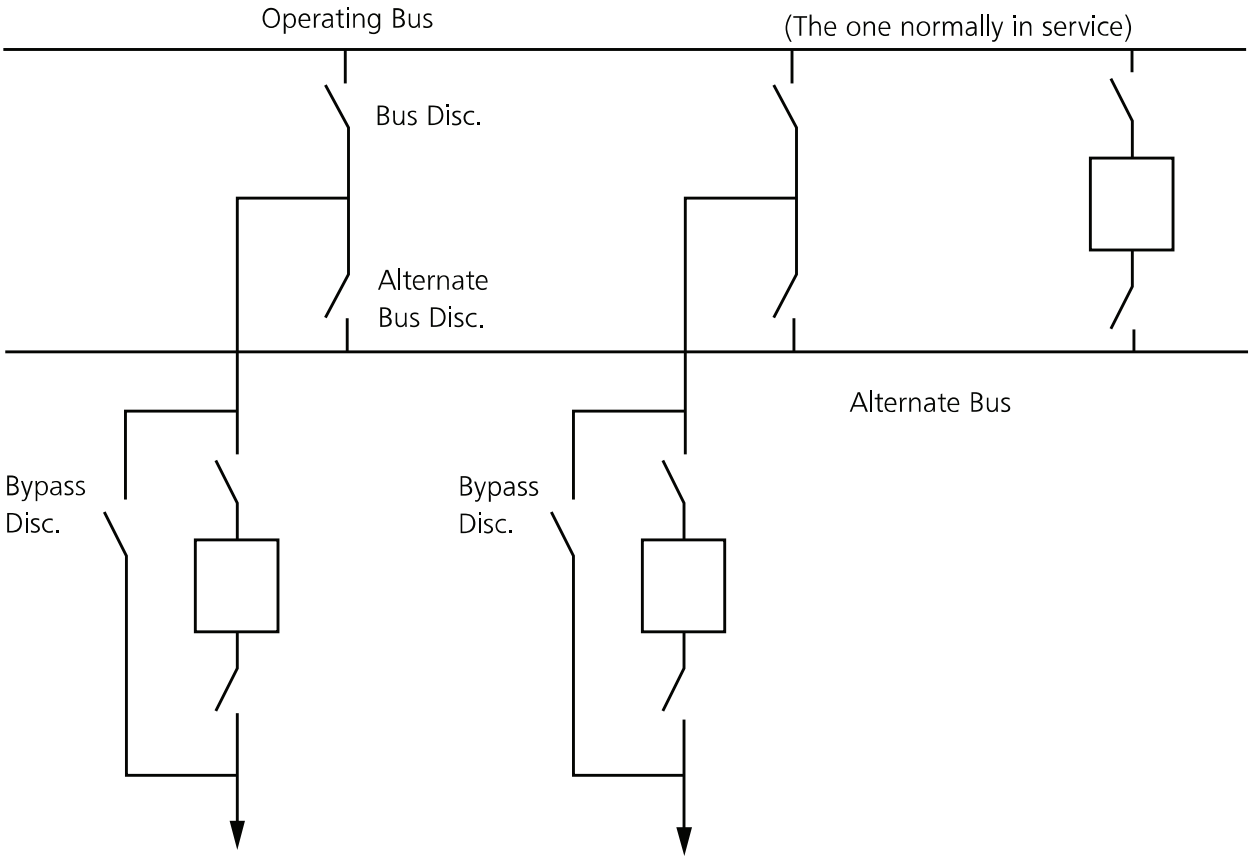

Operating Bus
(The one normally in service)
Bus Disc.
Alternate
Bus Disc.
Alternate Bus
Bypass
Disc.
Bypass
Disc.

Figure 15

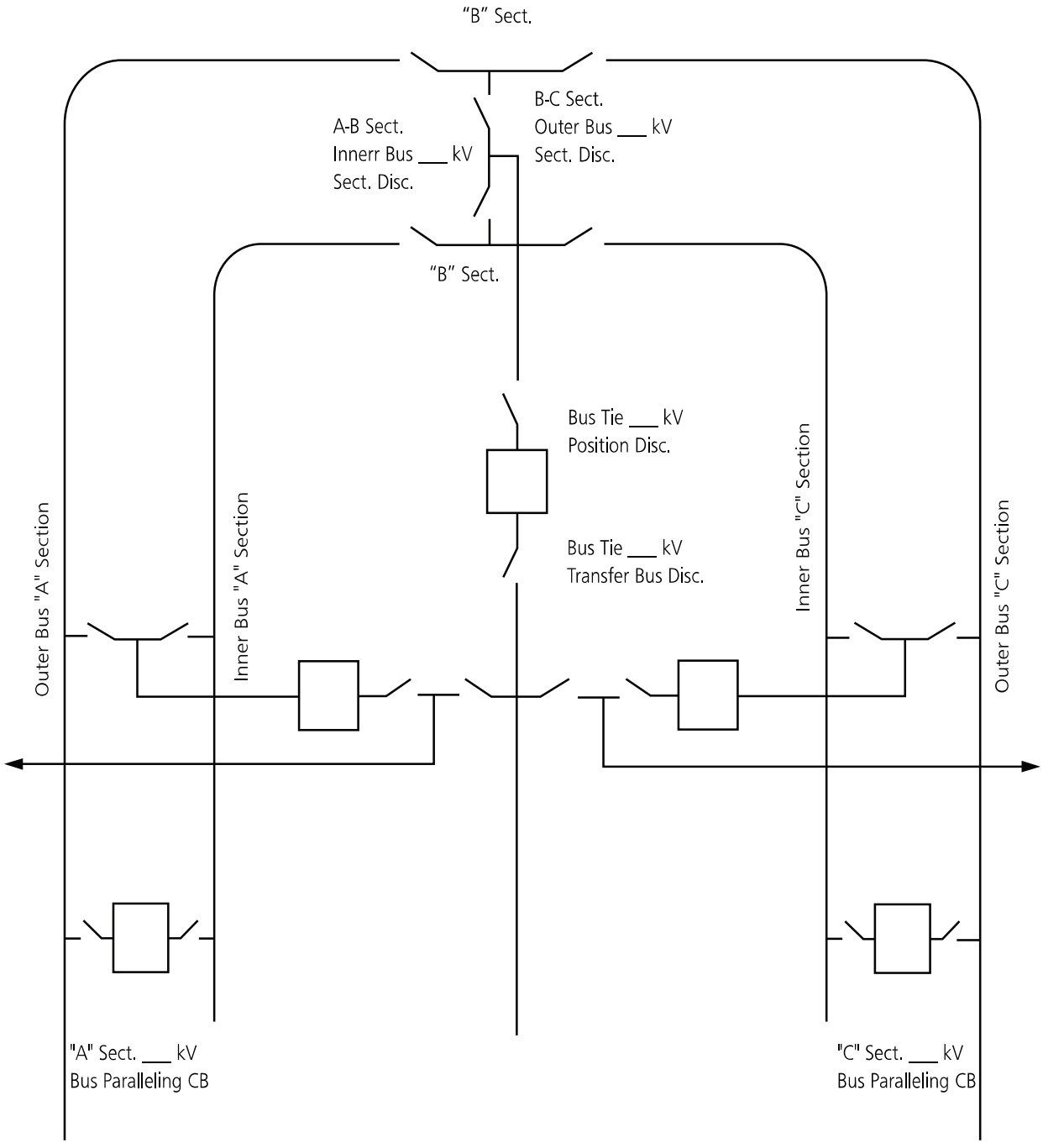
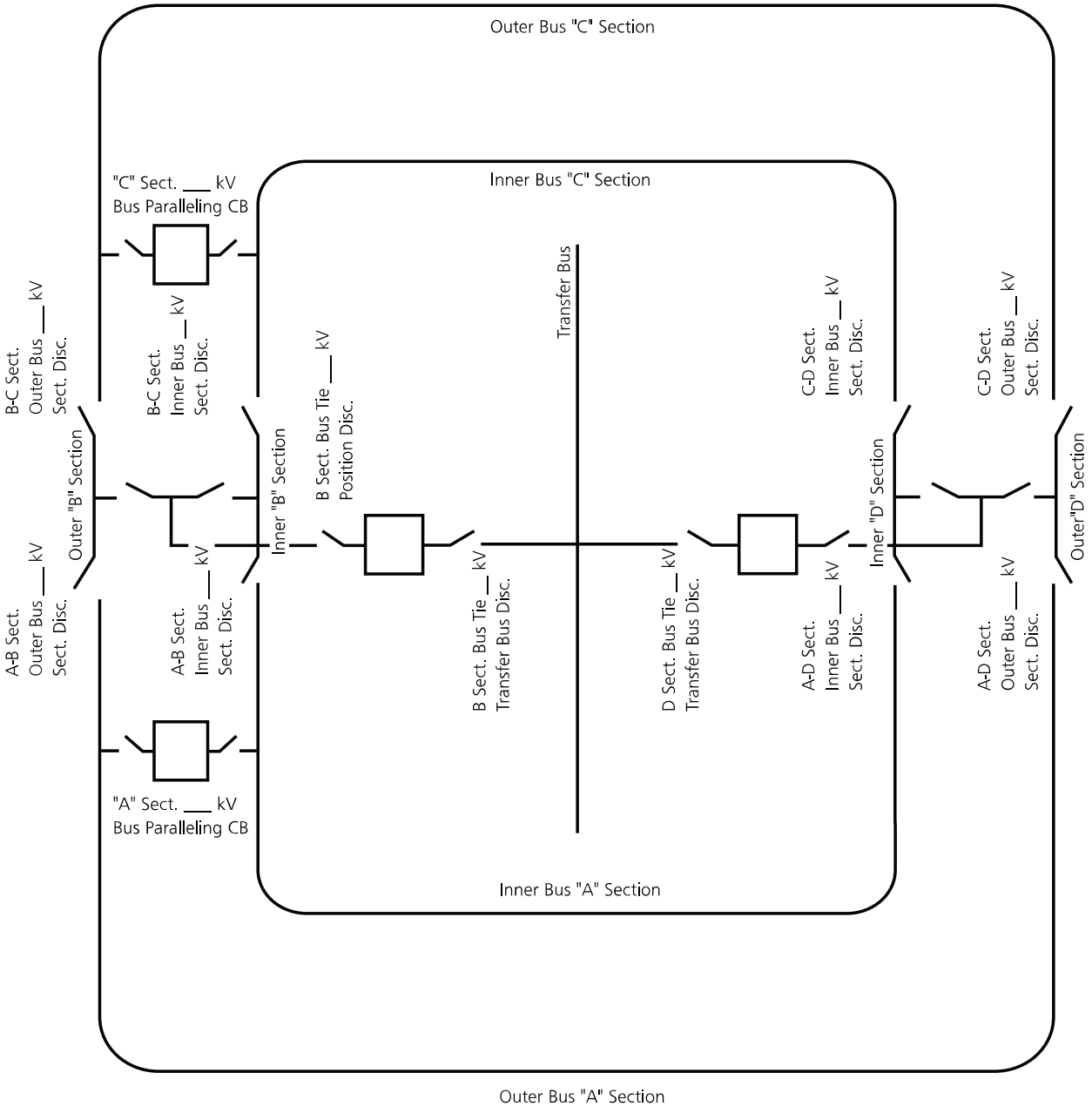

"B" Sect.
A-B Sect.
Innerr Bus ___ kV
Sect. Disc.
B-C Sect.
Outer Bus ___ kV
Sect. Disc.
"B" Sect.
Bus Tie ___ kV
Position Disc.
Bus Tie ___ kV
Transfer Bus Disc.
Outer Bus "A" Section
Inner Bus "A" Section
Inner Bus "C" Section
Outer Bus "C" Section
"A" Sect. ___ kV
Bus Paralleling CB
"C" Sect. ___ kV
Bus Paralleling CB

Figure 16


Outer Bus "C" Section
Inner Bus "C" Section
"C" Sect. ___ kV
Bus Paralleling CB
B-C Sect.
Outer Bus ___ kV
Sect. Disc.
B-C Sect.
Inner Bus ___ kV
Sect. Disc.
Outer "B" Section
Inner "B" Section
B Sect. Bus Tie ___ kV
Position Disc.
Transfer Bus
C-D Sect.
Inner Bus ___ kV
Sect. Disc.
C-D Sect.
Outer Bus ___ kV
Sect. Disc.
Inner "D" Section
Outer "D" Section
A-B Sect.
Outer Bus ___ kV
Sect. Disc.
A-B Sect.
Inner Bus ___ kV
Sect. Disc.
B Sect. Bus Tie ___ kV
Transfer Bus Disc.
D Sect. Bus Tie ___ kV
Transfer Bus Disc.
A-D Sect.
Inner Bus ___ kV
Sect. Disc.
A-D Sect.
Outer Bus ___ kV
Sect. Disc.
"A" Sect. ___ kV
Bus Paralleling CB
Inner Bus "A" Section
Outer Bus "A" Section

E2: Storage Batteries

1.0 General

The operation and maintenance of storage batteries installed in substations is the responsibility of Substation personnel. All abnormal conditions of the batteries and chargers must be reported to the switching center.

2.0 Inspections by Substation Personnel

2.1 At attended substations, the battery voltage should be read once each shift at approximately the same time.

2.2 Each inspection of an unattended substation is to include the inspection of the battery and recording of the DC voltmeter and ammeter readings. Where possible, the negative and positive voltage to ground should be read.

2.3 The normal float voltage varies with the different types of batteries. See Table 1.

Table 1: Normal Float Voltages for Different Types of Batteries

Battery Type	Normal Float Voltage (Volts)
60 Cell Antimony Battery	130–132
24 Cell Antimony Battery	52–53
60 Cell Calcium Battery	134–136
24 Cell Calcium Battery	53–55

2.4 With the substation load on the battery, regardless of the status of the charger, the battery terminal voltage should not below 2.16 volts per cell.

A. 24 cell battery — 51.8 volts

B. 60 cell battery — 130 volts

C. 120 cell battery — 260 volts

NOTE

Any battery found at or below this voltage should be immediately reported to the switching center. Also, all load possible should be removed (unscrew switchboard lights, and so forth) without affecting relay protection and operating circuits.

3.0 Maintenance by Substation Personnel

3.1 Battery cell exteriors must be kept clean and dry. To clean the outside of the cells, use a cotton rag dampened with water. Do not use any type of baking soda, solvents, detergent, or ammonia solution. Last, wipe dry with clean rag.

3.2 Only pure distilled or approved de-ionized water is to be added, as required, to maintain the electrolyte level. The correct electrolyte level on most cells is between the two liquid level lines. Those cells with only one line indicate the top level. In this case, the liquid should remain below but not more than one-half inch below this single mark. Do not overfill. Filling appliances must be clean.

NOTE De-ionized water used for washing insulators is not approved for battery water.

3.3 Never add acid or other fluids other than approved water to a cell.

3.4 Always log water additions.

3.5 Inspect all connections for tightness and corrosion. Loose and corroded connections are to be reported as an abnormality.

3.6 The condensed operating instruction sheet, provided by the Battery Shop Supervisor, is to be included with the standard station instructions at each location. This instruction contains the name of the battery manufacturer, date of installation, and other pertinent data required for proper operating and maintenance.

3.7 Battery cells will be numbered consecutively starting at the main battery positive terminal, with the highest number at the main battery negative terminal. Numbers are to be applied on or adjacent to at least every fifth cell.

3.8 Battery cells are normally kept at a specific floating voltage to maintain a chemical balance in the cell's construction. This voltage level is marked and should not be changed without consulting the battery supervisor.

WARNING An explosive mixture is present in all battery cells. Keep open flames or sparks away from the immediate vicinity of the battery.

E3: Emergency Power Systems

1.0 General

Emergency power systems have been installed in various Switching Centers to ensure substation operations when Station Light and Power becomes unavailable. It is vital that these systems be tested to determine if the generator, change-over gear, and respective inverters are performing properly.

2.0 Documentation

2.1 A log book is to be established and updated at each back-up generator location. The log will contain the date and time when the generator was run, the operator's name, the length of time the generator was operated, and the amps, volts, and frequency of the unit while operating.

2.2 A record is to be established and updated at each Station Light and Power change-over gear location. The record will show the date and time of all Station Light and Power change-over gear operations whether routine or emergency.

2.3 A record is to be established and updated showing the date and time of inverter operations as associated with the Uninterruptible Power Supply (UPS) and Substation Automated Systems (SAS) respectively. The record will contain the length of time the inverter carried load, whether routine or emergency.

3.0 Testing

3.1 The back-up generating unit shall be tested twice a year under load for a minimum of 30 minutes. The tests should include an actual Station Light and Power change-over gear operation.

3.2 The inverters associated with SAS shall be tested by removing the normal AC source and verifying inverter operation. The HMI will be shutdown before testing to ensure no memory is lost if inverters malfunction.

3.3 The inverters associated with the UPS systems are routinely tested by Power System Control twice a year by removing the normal AC source and verifying all critical loads. This test includes a verification of battery voltage and ampacity.

3.4 There shall be close communications and presence by all substation crafts involved and respective support groups when these tests are performed. This will ensure the most reliable response to the possible failure of any component within the emergency power system.

3.5 Discernment based on knowledge of back-up generator load capacity, Air Quality Management District regulations and specific substation characteristics should govern the time and date selected to perform these tests.

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E4: Power Fuses

1.0 General

Fuses are used on an electrical system to disconnect a faulted section of line or a piece of equipment from the remainder of the system. When current of sufficient magnitude flows, the fusible element will melt, interrupting the current flow.

WARNING A blown fuse is a signal to proceed with caution. Be sure the fault is cleared before changing the blown fuse. Station instructions should outline the proper procedure to change fuses safely.

2.0 Inspection

In all instances, check equipment to determine the cause of the fault after a fuse has blown. Most power fuses are used to protect transformers. In those installations where a fault has blown the fuse, check the following for evidence of trouble:

- Leads — Check all leads from the fuses to the transformer and the low-side leads including any rack structure.
- Transformer — Check for the presence of oil or smoke expelled from the transformer. Inspect for a blown diaphragm, excessive gas pressure, or relay targets.
- Insulators — Look for smoke damage, burned spots, cracks, or broken skirts.
- Customer Substations — Contact the customer to ensure the safety of their personnel and to determine the status of their equipment prior to re-energizing customer equipment.

If it is not possible to determine the cause of the blown fuse, the protected equipment will be tested prior to re-energizing.

3.0 Types of Fuses

There are three general types of power fuses used for transformers.

3.1 Solid Material Fuses

Solid material (SM) fuses are fuses with replaceable refill units generally used for the protection of smaller transformers, such as the Station Light and Power transformers. The design of this fuse provides for no mechanical damage associated with varying current levels. The high melting point of silver is such that you do not partially melt the element, therefore, it is required to replace the blown fuse only.

3.2 Solid Material Drop-Out Fuses

Solid material drop-out (SMD) fuses are used on larger transformers up to 115 kV rating. The drop-out feature makes this blown fuse easy to see. When the current magnitude melts the fusible element, a drive spring is released to unlatch the top of the fuse. The unlatched fuse will come to rest hanging open in the lower hinge assembly. The design of this fuse provides for no mechanical damage associated with varying current levels. The high melting point of silver is such that you do not partially melt the element, therefore it is required to replace the blown fuse only. The fuse section is non-renewable; however, the hardware on each end is removed and installed on a new fuse.

3.3 Boric Acid Drop-Out Fuses

Boric acid drop-out (HSO) fuses are used in similar locations as SMD fuses and have an operating limit of 34.5 kV.

4.0 Routine Operation of Power Fuses

In some cases switching is performed using SM fuses as a disconnecting device. Unless otherwise specified, these fuses are not designed to interrupt load; however, they may be used to interrupt magnetizing current when properly sized. It is critical that the correctly sized fuses are installed for the application.

As with any other disconnecting device, proper switching techniques must be followed when operating fuses. Where provided, secondary knife switches shall be opened prior to opening or closing SM fuses. SMD fuses shall only be operated when both sides of the fuse are de-energized.

5.0 Replacing Power Fuses

Once the inspection has been completed and the cause for the blown fuse is determined or equipment has been tested, all sources of supply to the fuse must be de-energized before the fuse replacement is attempted (SOB 100). In most installations there will be disconnects installed to isolate the fuses. In other locations, there may only be disconnects on one side of the fuses. Regardless of the disconnect configuration, it is imperative that both sides of the fuse be de-energized before a fuse is changed.

If more than one disconnect pole is available, use the shortest pole needed to remove or replace a fuse in the hinge. Then use the longer pole to close the fuse. Always use the proper disconnect pole in order to maintain control. When closing a fuse, any upward lifting on the fuse can cause it to become dislodged from the hinge.

After replacement of a fuse, re-energize with a circuit breaker when possible.

WARNING

Never stand under an energized SMD-type fuse. When an SMD-type fuse blows, it produces an exhaust that reaches several feet. Energized SMD-type fuses are enclosed by a fence or chain to prevent personnel from standing directly under them.

6.0 Spare Fuses

At least one set of spare fuses or links are to be kept at the substation for each type of fuse at that location. It will be the responsibility of the Maintenance Supervisor to insure that spare fuses are ordered and replaced when used.

E5: Metal-Clad or Cubicle Gear Circuit Breakers

1.0 General

1.1 The integrity of circuit breaker secondary circuits is critical to the reliability of the electrical system. In most cases, racking out cubicle or metal-clad circuit breakers results in the disconnection of the circuit breaker secondary circuits. All personnel having occasion to rack in/out circuit breakers for operation or maintenance purposes shall be familiar with the type of secondary circuit connections involved, for example, plug-in, pin/linkage, sliding contacts.

1.2 In those cases where the secondary circuits are disconnected as part of the rackout procedure, a close/open/close operation will be performed once the breaker has been fully racked in beyond the test position to ensure the integrity of the secondary circuit.

2.0 Capacitor Breakers

All current operating practices will continue to be followed. In the case of cubicle gear or metal-clad capacitor switching, allow a five minute period following the close/open prior to final closing as outlined in the APM, Rule 410.

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E6: Standardized PLC Cabinet Labeling

1.0 General

In an effort to establish some consistency in the labeling of PLC cabinets, it was decided to adopt the standard developed and currently in use at Lighthipe Substation. Standardization of PLC cabinet labeling is desirable in order to avoid confusion between stations and/or regions.

2.0 Labeling Specific Voltages

Table 1 shows the convention that has been established for labeling buttons or switches that affect one specific voltage only.

Table 1: Labels for Buttons or Switches that Affect One Specific Voltage

Label Color	Voltage (kV)
Black	500
Brown	220
Brown	115
Red	66
Green	33
Blue	16
Orange	12
Black	4

3.0 Labeling Non Voltage Specific Items

Table 2 shows the convention that has been established for labeling buttons, switches, information, or schemes that are not associated with a specific voltage.

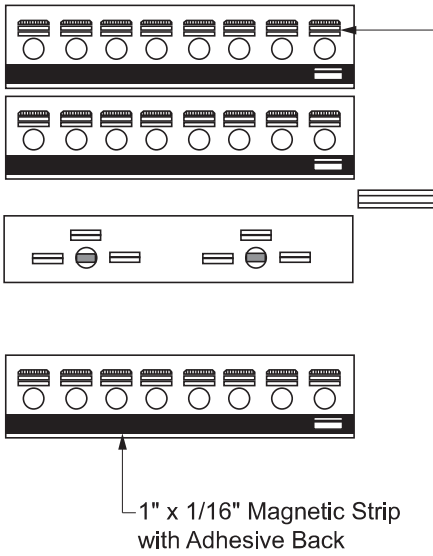
Table 2: Labels Not Associated with a Specific Voltage

Label Color	Types of Information
Yellow	Additional non-critical information such as legend, directions, and so forth
White	Schemes, test options, information (placed on the magstrip) regarding circuits

4.0 Labeling Materials, and So Forth

The labels are plastic with an adhesive backing produced by a standard P-touch (Brother) labeling machine in general use throughout the system. The magnetic strips below each row of buttons are 1" wide and 1/16" thick with an adhesive backing. The magnetic strips can be purchased in rolls from several sources.

Figure 1: Standardized PLC Labeling



Note(s):

1. Labels are standard, adhesive-backed, P-Touch labels manufactured by Brother.

E7: Sudden Pressure Devices

1.0 Failure of Sudden Pressure Devices using DPU relays for tripping

1.1 It is not possible to make individual unit sudden pressure relays solid at SAS installed stations using DPU relays for tripping. Any time the bank sudden pressure relay needs to be made solid to an individual unit, the entire bank sudden pressure relay scheme needs to be made solid.

1.2 This newer type scheme uses physical inputs of the relay which the sudden pressure device C-form contacts are wired to. The problem created is if a portion of this relay scheme has a problem and the technician elects to disable it by opening the FT switch associated with the individual unit. By opening the FT switch with the “A” and “C” wires still connected, half of the trip logic internal to the DPU relay is now satisfied because the normally energized input is now de-energized. At this point it only requires a voltage applied on the “A” wire of the out of service sudden pressure device to trip the remaining unit of the transformer.

1.3 The FT switch located under cover/glass that the common wire “B” is connected to should only be operated when it is necessary to de-energize the sudden pressure device for replacement.

1.4 Any time the FT switch is required to be opened the entire sudden pressure scheme shall be made solid and remain solid for the length of the FT switch being opened.

1.5 It has been agreed from protection engineering that the sudden pressure relay of a “B” bank can remain solid for an extended period of time as long as the bank differential relay remains automatic. If the bank in question was not equipped with a bank differential relay or if the bank differential relay needs to be made solid, notification to protection engineering would be required to see if the bank needs to be taken out of service due to inadequate protection.

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E8: Synchronous Condensers

1.0 General

Routine inspections and operation of synchronous condensers.

2.0 Air Cooled Machines

2.1 Inspect and clean brush rigging monthly.

2.2 Reverse field polarity every 720 hours of operation.

2.3 Annual servicing.

A. Inspect stator and rotor.

B. Clean with compressed air.

C. Change or filter bearing oil.

D. No reports required unless further action is necessary

2.4 Overhaul every four years.

2.5 When not in regular service.

A. Start once a month.

1. Run two hours near full load to keep windings dry.

3.0 Hydrogen-Filled Machines

3.1 Inspect and clean brush rigging every six months.

3.2 Reverse field polarity every 720 hours of operation.

3.3 It is not necessary to change bearing oil except on overhauls.

A. Do not filter bearing oil in hydrogen-filled machines.

B. Drain into open containers to allow hydrogen to escape.

3.4 Overhaul every five years.

3.5 Detailed written station instructions shall cover the following:

A. Purging and filling of machines at that station.

B. Materials normally used to repair machines at that station.

C. Water treatment methods.

D. Water tower cleaning and operating instructions.

E. Water flow test instructions.

4.0 Overhauls On Synchronous Machines

4.1 Clean and inspect the entire machine and water system.

A. Including all auxiliary equipment.

4.2 Change oil in the bearings.

A. Inspect oil rings.

4.3 Make the following tests:

A. Hydrostatic tests of water lines.

B. Bearing free flow tests.

C. Michrohm readings on all leads to the collector rings.

D. Pedestal insulation tests.

E. Test thermometers.

F. Test all gauges.

G. Test ground detectors.

H. Check alarm circuits.

I. Test temperature detectors.

J. Make shorted turns tests.

K. Make insulation resistance tests.

L. Make overvoltage tests.

M. Make underspeed relay tests.

N. Test all auxiliary equipment.

4.4 The following reports shall be forwarded to the Substation Maintenance Manager.

A. Overhaul letter.

B. Inspection report.

C. Synchronous matching overvoltage report.

D. Condenser bearing report.

4.5 Forward one copy of overvoltage report to Apparatus Division General Office.

E9: Online Transformer Monitoring (OTM) Equipment Inspection

1.0 General

The OTM system provides continuous monitoring of the health of “A” and “AA” transformer banks. It automatically performs dissolved gas analysis (DGA) and monitors the condition of the transformer bushings along with partial discharge levels on our “in-service” transformers. The system setup has the capability to provide system operators with real time updates on the state of “A” and “AA” banks through SCE's Energy Management System (EMS).

The DGA equipment continuously monitors any development of key gases with the transformer. The bushing and partial discharge monitoring equipment is used to detect changes in power factor (PF) and capacitance values within a transformer's high and low side bushings. The partial discharge (PD) monitor along with acoustic sensors is designed to detect high frequency electrical pulses within a transformer.

Acoustic sensors were discontinued from installations starting in 2017.

The two major components of the OTM system are the dissolved gas analysis (DGA) monitors and the bushing along with partial discharge (PD) monitors. The equipment shall be inspected as conditions indicate. Additional information and instructions can be found in the manufacturer's manual.

2.0 Dissolved Gas Analysis (DGA) Equipment

2.1 The DGA equipment is mounted on a stand next or close to the transformer. It continuously monitors any development of the following gases: Hydrogen (H2), Oxygen (O2), Methane (CH4), Carbon Monoxide (CO), Carbon Dioxide (CO2), Ethylene (C2H4), Ethane (C2H6), Acetylene (C2H2) and total gases. There are two types of DGA monitoring devices, one for monitoring the transformer main tank (TRANSFIX) and one for monitoring both the transformer main tank and the On-Load Tap-Changer (TAPTRANS).

A. Alarms: The presence of an alarm should be immediately reported to Apparatus and Maintenance Supervisor. The units have a front panel that displays four LED lights that indicate the following:

1. Blue — Maintenance required
2. Green — Normal
3. Yellow — Caution
4. Red — Critical

B. Air Filter Cleaning — the air filter is located on the right side of the unit. The filter may need occasional cleaning and it will be indicated by a non-critical TRANFIX error or TAPTRANS error, "Zone 2 temperature too high" indication on the LCD information screen and/or a blue maintenance light alarm.

1. Slide up the cover on the right hand side on the unit casing to reveal the black fan/filter assembly.

2. If a cable-tie is fitted to the filter holder, remove it carefully. Remove the filter holder by pulling off the black snap-off cover to the filter.

3. If the filter is oily, clean it with mild soap and water, and then dry it thoroughly.

4. Replace the filter and snap the cover back in place. The cable-tie does not need to be replaced as it is provided for transport only.

5. Slide the cover down over the filter.

   The TRANSFIX unit draws air from the right side of the unit and exhausts it on the bottom.

C. Oil Filter Cleaning - The oil filter may need occasional cleaning and this will be indicated by a non-critical TRANFIX OR TAPTRANS error, “oil pressure too low” or “oil pump tacho count too high” on the LCD information screen, and/or a blue maintenance light alarm.

1. The power to the unit must be switched off and the oil supply valve must be closed before removing the filter housing.

2. The compression nuts on either side may need to be loosened slightly to turn the filter to a more convenient position, and must be re-tightened once the procedure is complete.

3. If a measurement is in process, press the red pushbutton labeled STOP MEASUREMENT. This will abort the process and the unit will return to standby mode. Switch OFF the power to the unit once it is in standby mode.

4. Remove the nut that houses the filter. The filter is inside; care must be taken for the enclosed spring. A small amount of oil will leak out of the filter.

5. Remove the filter and clean the filter, the filter may be cleaned with a brush and compressed air. After cleaning, place it back inside and replace the housing.

6. Replace and tighten the nut; using a backing wrench to hold the filter housing in place.

7. Turn the power back on and the unit will automatically begin measuring at the next scheduled run.

3.0 Bushing and Partial Discharge (PD) Monitoring

3.1 The bushing and partial discharge monitoring equipment is used to detect changes in power factor (PF) and capacitance values within a transformer's high and low side bushings. The

partial discharge (PD) monitor along with acoustic sensors is designed to detect high frequency electrical pulses within a transformer.

Acoustic sensors were discontinued from installations starting in 2017.

The sensors are placed at specific locations on the transformer and their wires are routed through a conduit to a central microprocessor unit.

A. Alarms: The presence of an alarm should be immediately reported to the Maintenance Supervisor. The central microprocessor unit has a front panel that displays three LED lights that indicate the following:

1. Green — Solid green light indicates normal operation
2. Green — Blinking green light, about every 3 seconds, unit is taking measurement and it may take up to 3 minutes to complete measurement
3. Green — Blinking green light, about once per second, unit may have an error or hardware problem with module
4. Yellow — Warning
5. Red — Critical

4.0 System-Generated Alarms

The OTM system will generate alarms to indicate the condition of the hardware and also combine the DGA and Bushing monitoring data and generate alarms based on the condition of the transformer. Hardware condition alarms, such as loss of communication will be reported to TS&S and Apparatus Engineering. TS&S will notify PSC and appropriate maintenance supervisor.

The four levels of alarms that indicate transformer condition will be reported through the EMS as follow:

Normal — System is operating normally; no action required.

Caution — Indicates that the first alarm threshold level has been reached, for example an increased rate of gas generation of key gases. Reported to TS&S and Apparatus Engineering. Determine cause of alarm, change sampling rate at which the units takes a sample.

Warning — Indicates that the second alarm threshold level has been reached. Reported to TS&S, Apparatus Engineering, and appropriate SC&M Maintenance supervisor. Determine cause of alarm, change sampling rate at which the units take a sample

Critical — Highest alarm threshold level has been reached. TS&S, Apparatus Engineering, and appropriate SC&M Maintenance supervisor.

- TS&S, Apparatus Engineering, and Appropriate Maintenance supervisor must be contacted immediately to determine the cause of the alarm. A critical alarm is an indication of an incipient fault and the transformer may be experiencing one or a combination of the following: substantial partial discharge intensity, a change in power factor in the transformer bushing, and/or gases evolving at a fast rate.

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Section T: Tools

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T1: Live Line Tools

1.0 General

Live line tools, in particular, hot sticks, are an important tool that many of our employees use on a daily basis. Their maintenance and care is a key factor for safety and reliability. How we care for, maintain, and store these tools will determine whether or not we have safe tools in our hands. This SOM policy includes some basic information about live line tools.

2.0 Definitionh1

Per the APM, live line tools are defined as approved tools which are especially designed for work on exposed energized high-voltage lines and equipment.

3.0 SCE Criteria for Live Line Tools

All live line tools will be approved by the Corporate Safety Department and Construction Methods before being put into use. There will be no alterations made without approval. Refer to APM, Rule 104 b.

When using live line tools, employees shall not place their hands closer than is absolutely necessary to the energized line or the energized metal parts of the tool being used and in no case closer than specified in APM, Rule 147.

Employees working with live line tools will use adequate protective equipment on primary conductors, low-voltage conductors, telephone circuits, and other wires which are within reaching distance. Refer to APM, Rule 222 d.

Hold out ropes of live line tools being used to spread or raise conductors should be securely fastened and not held by employees except as necessary to secure or release them. Refer to APM, rule 222 e.

Live line tools are not to be hung on a conductor. Approved hangers or bags are to be used. Refer to APM, Rule 222 f.

Wood sticks are no longer acceptable for use in Substations.

Table 1: Manufacturers of Live Line Tools Used at SCE

Manufacturer	Color
A.B. Chance	Red-Orange
Hasting	Yellow
Kearney	Dark Brown
Safety Line	Dark Brown
S&C	Dark Brown or Yellow

Table 2: CAL OSHA Regulations

Regulator	Regulations
CAL OSHA	Each live line tool shall be wiped clean and visually inspected for defects before use

4.0 Live Line Tool Dielectric Properties

A hot stick can become electrically unsafe when either of the following conditions is present:

4.1 Internal conductivity can result from moisture, dielectric deterioration or internal structure changes

4.2 Surface conductivity can result from a combination of loss of gloss-wetting and contamination

NOTE

Surface moisture alone can render a tool unsafe if the surface is non-glossy. This allows for moisture to "wet-out" (cover) the entire surface.

5.0 Live Line Tools (Hot Stick) Design

Insulated parts of live line tools shall have manufacturers' certification to withstand a minimum test of 100,000 volts per foot of length for five minutes.

6.0 Care

6.1 Care of Live Line Tools

A. All live line tools shall be properly stored during transportation.

B. Live line tools should be stored in suitable bags, or in the appropriate truck or tool trailer compartments, or in appropriately designed holders at manned and unmanned stations until ready for use.

C. Storage shall be in a manner to minimize damage caused by movement during transportation.

D. Proper storage includes a clean, dry, indoor location (when feasible) and positioned so its shape is not altered.

E. When stored outdoors, live line tools should be protected from sun and moisture (for example, long pipe capped at both ends, ventilated, and shielded or insulated from direct sunlight).

F. When live line tools are staged for use they should be leaned up against a clean, dry place, or placed on a rack, or placed on a clean, dry tarp on the ground.

G. Never lay live line tools on the grass, rock dust, pavement, or ground without a clean, dry tarp.

H. While in use, they should be kept out of the weather and in a clean, dry place for as long as possible.

I. Live line tools should be sent up the pole/structure in an approved hot stick bag.

7.0 Inspection and Cleaning of Live Line Tools

It is of utmost importance that all hot sticks, disconnect poles, and ground sticks be inspected and cleaned before using each day. Remember, these tools are what separate you from an energized source.

7.1 Visual inspection shall include a check for obvious signs of deterioration that are likely to negatively affect the insulating characteristics or safe operation, such as:

A. Deep or significant:

1. Scratches
2. Cracks
3. Chips
4. Gouges

B. Holes

C. Splintering

D. Abrasions penetrating into the core

E. Flaking

F. Dulled surface/deteriorated finish (blooming)

G. Other conditions affecting safe operation, which may include:

1. Missing or loose end caps
2. Bent rivets or bolts
3. Excessive wear on metal parts
4. Bent or otherwise damaged parts
5. Improperly functioning attachments, latches, levers.

NOTE

If a live line tool shows signs of damage and the user is not confident that it can be used safely, it must be removed from service and put aside for inspection and/or disposal.

7.2 Dry Cleaning (Preferred Method) shall include the following:

A. Fan off excessive dust build-up before wiping to prevent scratching during cleaning.

B. Wipe with clean absorbent cloth.

C. Clean with spiral motion from top to bottom of pole (that is, rotate pole while cleaning to avoid longitudinal scratches).

D. If dry wiping does not remove contamination, use the wet cleaning method (see 7.3).

E. Coat with silicone using clean silicone wipe (SAP 10149663).

1. Wipe in a circular motion (not up and down).

7.3 Wet Cleaning Method (only when Necessary)

Do not use deionized water with this cleaning procedure.

a. Thorough cleaning of the live line tool should only be done when the tool has visible signs of contaminants which cannot be removed with a clean, dry, soft cloth.
b. Use mild liquid dish detergent and generous amounts of water. (Hastings All Purpose Cleaner may be used, if available. SAP 10178810)
   • All soap residues must be removed with water and then wiped with a clean, dry, soft cloth.
c. Do not use any cleaners that have abrasives or harsh chemicals in them.
d. Allow the tool to dry.
e. Follow 7.2 above.

8.0 Testing of Live Line Tools

8.1 Special Inspection for Work Outside California

A. For non-California facilities and for crews working outside California, the following additional requirements apply:

B. Live line tools which are hollow (for example, telescopic hot sticks) shall be inspected and tested every 2 years.

C. The Inspection and Test shall be documented.

D. Live line tools which are made of fiberglass reinforced plastic (FRP) rod or foam-filled FRP tube construction:

1. This type of live line tool on trucks shall have monthly inspections documented on the foreman's Monthly Inspection and Safety Report.
2. This type of live line tool in-service at both manned and unmanned non-California facilities shall have inspections documented on a monthly facility inspection form.

These inspection reports document inspection of each of these live line tools and serve to demonstrate that the tool has no defects that could cause it to fail in use, as required by the federal regulations.

9.0 Don'ts:

1. Do not use live line tools to pry or beat on equipment.
2. Do not use attachments that are not designed for use with that specific live line tool.
3. Do not apply tape marks or other means of marking to the surface of the live line tool, except as required by APM Rule 222a and approved by the appropriate Construction Methods group.
4. Do not attach line or "pigging" strings to live line tools, except temporarily to facilitate the raising and lowering of tools.
5. Do not permit prolonged exposure of live line tools to moisture, dirt, or ultraviolet rays.
6. Do not use for any purpose other than that for which the live line tool was intended.
7. Do not expose to outside elements for extended periods of time
8. Do not use wooden live line tools.
9. Do not alter, modify, or drill live line tools. Any need for modification shall be addressed through the appropriate Construction Methods group.

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T2: Tools and Tool Identification

1.0 General

Having the proper tool is an important part of accomplishing any job. The grade of a craftsperson's work is generally reflected in his/her use and care of tools.

Each substation employee will supply his/her own tool box containing small personal tools where required. SCE will provide all specialized and power tools.

2.0 Identification and Record of Tools

2.1 Substation management shall provide a method of marking all SCE tools to identify the location and crew to which each tool is assigned.

2.2 An inventory of all SCE tools shall be kept up-to-date and ready for audit at all times. Any lost or stolen tools must be reported at once.

2.3 Roto keys used by substation maintenance and test personnel shall be color coded to identify the crew to which they are assigned. These roto keys must be mounted in a rack on a board so that each one can be accounted for at all times.

3.0 Approved Tools

3.1 The tools purchased by SCE for use have been approved by the tool committee. Their approval indicates that the tool is safe for the job it designed to do. If for some reason, in your opinion, the tool is not safe, inform your supervisor. The supervisor on the job will determine if the tool is to be used or replaced.

3.2 Do not bring in a tool that is not approved or is in an unsafe condition to use on SCE jobs.

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Section RC: Regulatory Compliance

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RC1: NERC Physical Access to Restricted Areas within Switching Centers and Substations (OBSOLETE)

1.0 General

This policy is intended to support SCE's compliance with the North American Electric Reliability Corporation (NERC) Reliability Standards, of which Critical Infrastructure Protection (CIP) Standards 002-009 apply to the protection of Critical Cyber Assets (computers, software and equipment) that support the Bulk Electric System (BES). The purpose of the NERC Physical Access Policy is to reduce risks to the reliability of the BES through the compromise of associated Critical Cyber Assets (CCA).

2.0 Emergencies

2.1 This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of CCA that support the Bulk Electric Systems (BES). Suspension of this policy must be explicitly authorized by the Grid Control Center (GCC) Real-Time Dispatcher.

2.2 Exceptions to this policy (including where implementation is not technically feasible) must be promptly documented and reported in the Grid Control Center Morning Report.

3.0 Policy Statements

3.1 General

Physical Security processes and procedures must comply with all existing SCE policies and standards as well as the NERC Reliability Standards, where technically feasible. Where there is a conflict, the more restrictive rule will prevail.

3.2 Appropriate Use of Access Controls

A. Personnel that have unescorted physical access to NERC Restricted facilities or areas, as defined below, must have their company-issued ID Badge visibly worn at all times.

B. At no time will any person loan or knowingly allow another person to use their ID Badge to gain access to NERC Restricted facilities or areas.

C. All personnel approved for unescorted physical access to physical security perimeters at NERC Restricted facilities or areas must use their company-issued ID Badge to gain access via the ID Badge reader. In the event that all ID Badge readers are inoperable, an alternative authentication process will be followed. When an alternative authentication process is used, the date, time, and individual(s) name(s) shall be recorded in the Switching Center Log by the System Operator in charge.

D. Personnel who have been granted unescorted physical access must report the loss of their ID Badge to Corporate Security immediately upon discovery.

E. Supervisors of personnel who no longer require unescorted physical access to NERC Restricted facilities or areas must notify Corporate Security immediately.

3.3 Visitors

A. All personnel who have not been granted unescorted physical access to NERC Restricted facilities or areas are considered visitors. All visitors must be escorted by a person or persons who have unescorted physical access to the NERC Restricted facility or area. Visitors must be escorted at all times while within the NERC Restricted facility or area. Personnel escorting visitors must accompany the visitor(s) continuously with dedicated attention at all times. Additional escorts may be required depending on visitors' proximity to escort.

B. All visitors must sign in and out using the NERC CIP Visitor's Log and indicate their name, date and time of the visit, and the purpose of the visit.

C. Escorts must sign the log at the time visitors sign in. One escort signature may be used for multiple visitors. The escort is not required to sign out at the time the visitor(s) leave(s) the restricted space or area.

3.4 Access Management

A. Records of personnel with unescorted access will be reviewed quarterly by the employee's supervisor using the Security Access Verification System (SAVS). Any changes in access privileges deemed necessary during this quarterly review will be made within seven calendar days. Records of these changes will be kept on file for one year.

B. A list of personnel authorized to approve unescorted access to restricted areas (e.g., physical security perimeters) will be maintained by Corporate Security and will be reviewed and approved by the Grid Operations Director or designee, at least annually.

C. Managers or Supervisors must submit an online Access Order to request unescorted physical access to NERC Restricted facilities or areas. Refer to G-14 Attachments for details.

D. Personnel who are terminated for cause must have their access privileges removed within 24 hours.

E. Physical Access privileges may be revoked at any time without prior notice.

3.5 Personnel Risk Assessment (PRA) Requirement

A. All personnel must pass a Personnel Risk Assessment (background check) prior to being granted unescorted physical access to NERC Restricted facilities or areas. The Personnel Risk Assessment (background check) will consist of a criminal conviction check and a social security trace.

B. The Personnel Risk Assessment (background check) must have been completed within the previous seven year period or a new background check will be conducted.

C. Recurrent (every 7 years) Personnel Risk Assessments (background checks) are required for personnel who continue to maintain unescorted access to NERC Restricted facilities and areas.

3.6 Training Requirement

A. All personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets must complete NERC CIP Security training.

B. Annual training is required for personnel who continue to maintain access to NERC Restricted facilities or areas.

3.7 Monitoring

A. All activities within the designated physical security perimeters (PSP) at NERC Restricted facilities or Areas are subject to monitoring and logging. Access logs will be kept for a minimum of ninety (90) calendar days. Logs pertaining to reportable incidents will be retained for three (3) calendar years.

B. Attempts, successful or unsuccessful, to disable or otherwise circumvent security devices (alarms, sensors, door locks, card readers etc.) protecting NERC Restricted facilities or areas must be logged in the Switching Center Log and reported to the Grid Control Center and Corporate Security. Personnel who attempt to disable or otherwise circumvent security devices protecting NERC Restricted facilities or areas will be subject to disciplinary action up to, and including, termination.

C. Attempts, successful or unsuccessful, to gain unauthorized access to Critical Cyber Assets must be logged in the Switching Center Log and reported to the Grid Control Center and Corporate Security. Personnel who attempt, successfully or unsuccessfully, to gain unauthorized access to Critical Cyber Assets will be subject to disciplinary action up to, and including, termination.

D. Records of routine alarm response will be retained for one (1) calendar year. Alarm records pertaining to a reportable incident will be retained for three (3) calendar years.

E. All reportable incidents will be investigated by the SCE IT Anti-Vulnerability Emergency Response Team (AVERT).

3.8 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

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RC2: NERC Physical Access to Restricted Areas Procedure in Switching Centers and Substations (OBSOLETE)

1.0 General

This procedure is to clarify SCE's Policy with the NERC Reliability Standards, of which Critical Infrastructure Protection (CIP) Standards 002-009 apply to the protection of Critical Cyber Assets (computers, software, and equipment) that support the Bulk Electric System (BES).

2.0 Emergencies

2.1 This procedure may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of Critical Cyber Assets that support the Bulk Electric Systems. Suspension of this procedure must be explicitly authorized by the Grid Control Center (GCC) Real-Time Dispatcher.

2.2 Exceptions to this procedure (including where implementation is not technically feasible) must be promptly documented in the Switching Center Log and reported in the GCC Morning Report.

3.0 Procedure

3.1 General

A. There are two types of access to NERC Restricted facilities or areas: escorted or unescorted.

B. NERC Restricted facilities or areas have primary access doors with a combination of ID Badge reader/anti-tailgate device and intercom, and secondary access doors with ID Badge reader/anti-tailgate device only. Some locations (i.e., Telecom rooms or unmanned locations) are equipped with ID Badge reader/anti-tailgate device combinations only.

C. The primary and secondary access doors are equipped with anti-tailgating detectors intended to ensure single person entry per ID Badge read.

D. All remaining doors to the NERC Restricted facilities or areas are for planned maintenance or emergency exit only and are equipped with alarms. Any alarm generated by use of the emergency exit doors are received and logged by Corporate Security and entered by the System Operator in the Switching Center Log.

3.2 Unescorted Access

A. All traffic in or out of NERC Restricted facilities or areas will be through primary or secondary access doors. For a Switching Center, Telecom/unmanned location Unescorted Access Information Job Aid refer to Attachment “A” for Switching Centers and Attachment “B” for Telecom/unmanned locations.

B. At the time of entry through an access door, ensure no other person attempts to follow you.

C. When a group of personnel is entering, each person will need to use the ID Badge reader and verify a green light is displayed on the card reader before proceeding. If a red light is displayed, do not proceed. Make a second ID Badge read and verify green light in order to proceed. Note: the door does not have to close before the next person's ID Badge read and entry.

D. If ID Badge reader is inoperable at the Primary PSP Door, Corporate Security will be notified.

1. Person entering NERC Restricted facility or area will use the intercom (A- Phone) located at the primary access door. If there is no answer or unable to answer, use the Ring Down Phone to contact Corporate Security at PAX (8) 42911 or (626) 815-5611 to receive instruction. The System Operator will make an entry in the Switching Center Log.

2. Corporate Security will advise the Requestor to scan their badge at the Secondary PSP Door (if available) to obtain access.

E. In the event that all ID Badge readers are inoperable, the alternative authentication process is as follows (system operator will document all of these manual PSP entries in the Switching Center Log including name, supervisor name, reason for alarm, and Corporate Security contact name):

1. Person entering NERC Restricted facility or area will use the intercom (A- Phone) located at the primary access door. If there is no answer or unable to answer, use the Ring Down Phone to contact Corporate Security at PAX (8) 42911 or (626) 815-5611. After verifying certain information from the caller, Corporate Security will remotely unlock the Primary PSP Door.

2. If the Primary PSP Door cannot be remotely unlocked, Corporate Security will attempt to remotely unlock the Secondary PSP Door (if available).

3. If neither of the remote door unlocks are successful, Corporate Security will remotely unlock the SWATBox key holder located next to the Primary PSP Door (Note: Only a NERC CIP qualified person with unescorted physical access to PSP will be allowed access to keys stored in the SWATBox).

   a. Requestor will be instructed by Corporate Security to press open SWATBox door and twist the 6-pin key 90º counterclockwise to remove.The 6-pin key must be returned to the SWATBox and is contained within the larger key core.

   b. Requestor to close SWATBox door once key is removed. (**Note**:6-pin key must be returned to the SWATBox within 30 minutes of issue. Corporate Security must be notified before the 30 minute time limit expires if continued key use is deemed necessary.)

   c. Utilize the 6-pin key to unlock the Primary PSP door and achieve access to the PSP.

   d. When access to the PSP is no longer required, the Requestor is to use the intercom (A- Phone) located at the primary access door. If there is no answer or unable to answer, use the Ring Down phone to contact Corporate Security

at PAX (8) 42911 or (626) 815-5611 to remotely unlock the SWATBox for key return. The Requestor will return the key to the SWATBox 6-pin key core by inserting the key and twisting 90º clockwise to the secured position. (Note: The original authorized Requestor of the key must be the person that returns the key to the SWATBox)

e. Requestor to close SWATBox door once key is properly secured.

4. If Corporate Security cannot remotely unlock the SWATBox, a 4-digit PIN code will be issued by Corporate Security to the Requestor. The Requestor will slowly enter the pin into the SWATBox (no faster than one number per second), and steps 3a through 3e above will be followed.

5. If the SWATBox cannot be remotely unlocked and does not have power to enter a PIN, contact Corporate Security using the instructions in Section *E.1*.

   a. The person requesting access must determine if immediate access to the PSP is critical.

   b. If access is deemed critical, the person requesting access must contact GCC for further instruction. GCC can be contacted at PAX 46717 or (626) 308-6717.

   c. If access is not critical, the person requesting access must wait for the on-call Security Coordinator to arrive on-site to manually unlock the PSP Door.

6. In the event an ID Badge is not working at a switching center, follow the escorted process to gain entry. Report problem to Corporate Security at PAX (8) 42911 or (626) 815-5611 and make an entry in the Switching Center Log. Corporate Security will then provision access to the individual requiring access.

F. Certain PSPs contain NERC Hatches and/or Cabinets that can only be accessed using a 5-pin key located within the SWATBox. The NERC hatch and cabinet access steps are as follows (System Operator will document all of these manual PSP entries in the Switching Center Log including name, supervisor name, reason for alarm and Corporate Security contact name.):

1. Person requesting access to a NERC hatch or cabinet within a NERC Restricted facility or area will use the intercom (A- Phone) located at the primary access door. If there is no answer or unable to answer, use the Ring Down Phone to contact Corporate Security at PAX (8) 42911 or (626) 815-5611.

2. After verifying certain information from the Requestor, Corporate Security will remotely unlock the SWATBox key holder located outside the Primary PSP Door. (Note: Only a NERC CIP qualified person with unescorted physical access to PSP will be allowed access to keys stored in the SWATBox.)

   a. Requestor will be instructed by Corporate Security to press open SWATBox door and twist the 5-pin key 90º counterclockwise to remove. The 5-pin key is located in the back of the SWATBox and is contained within the smaller key core.

b. Requestor to close SWATBox door once key is removed.

c. Utilize the 5-pin key to unlock the NERC Hatch or Cabinet lock. (Note: Requestor is to unlock the lock at the access point but is not to open the access point door itself. Requestor is to return the key to the SWATBox prior to opening the access point door. The Requestor can keep the phone line open with the Corporate Security or may hang up and call back once the access point lock has been unlocked.)

d. After unlocking the hatch or cabinet lock, the Requestor is to use the intercom (A- Phone) located at the primary access door. If there is no answer or unable to answer, use the Ring Down phone to contact Corporate Security at PAX (8) 42911 or (626) 815-5611 to remotely unlock the SWATBox for key return (Note: The original authorized Requestor of the key must be the person that returns the key to the SWATBox.)

e. Corporate Security will verify the identity of the Requestor and unlock the SWATBox for key return. The Requestor will return the key to the SWATBox 5-pin key core by inserting the key and twisting 90° clockwise to the secured position.

f. Requestor is to close SWATBox door once key is properly secured.

g. Requestor is to re-establish communication with Corporate Security once Requestor is standing at the Hatch or Cabinet access point. Corporate Security will inform the Requestor when they are clear to open the access point.

h. When access to the NERC Hatch or Cabinet is no longer required, Requestor is to properly secure the access point lock and notify Corporate Security that access is no longer necessary.

3. If Corporate Security cannot remotely unlock the SWATBox, a 4-digit PIN code will be issued by Corporate Security to the Requestor. The Requestor will slowly enter the pin into the SWATBox (no faster than one number per second), and steps 2a through 2h above will be followed.

4. If the SWATBox cannot be remotely unlocked and does not have power to enter a PIN, contact Corporate Security using the instructions in F1.

   a. The person requesting access must determine if immediate access to the PSP is critical.

   b. If access is deemed critical, the person requesting access must contact GCC for further instruction. GCC can be contacted at PAX 46717 or (626) 308-6717.

   c. If access is not critical, the person requesting access must wait for the on-call Security Coordinator to arrive on-site to manually unlock the NERC hatch or cabinet.

G. Personnel who have been granted unescorted access and do not have their ID Badge will follow process 3.2(E).

3.3 Escorted Access

A. All personnel who have not been granted unescorted physical access to NERC Restricted facilities or areas are considered visitors. For a Switching Center or Telecom/Unmanned Location Visitor Information Job Aid, refer to Attachment "C" or "D".

B. Visitors are required to make an appointment in advance by contacting a Substation Operations Supervisor. Telecom or unmanned location visitors are required to contact the appropriate responsible employee with unescorted access.

C. For a real time field issue or program related request, contact the System Operator to make arrangement for entry to switching centers.

D. All visitors must be escorted by a person or persons who have unescorted access to the NERC Restricted facility or area.

The escort will need to disable the anti-tailgate device:

1. Obtain the anti-tailgate device key from the Substation Operations Supervisor, System Operator, or designated storage location in the Telecom Room or unmanned location.

2. Turn off the anti-tailgate device.

3. Open the door to allow the visitor(s) into the NERC Restricted facility or area.

4. Close the door and turn on the anti-tailgate device.

5. Return the key to the Substation Operations Supervisor, System Operator, or designated storage location in the Telecom Room or unmanned location.

E. When an access door needs to be held open for an extended period, i.e., delivery of equipment, use the following procedure:

1. Corporate Security will be notified at PAX (8) 42911 or (626) 815-5611 of intent to disable the anti-tailgate device and prop door open for delivery.

2. Turn Off the anti-tailgate device with key from the Substation Operations Supervisor, System Operator, or designated storage location in the Telecom Room or other unmanned location.

3. Hold open the access door. The door must be under direct observation at all times it is held open.

4. When the delivery is completed, close the door, turn on anti-tailgate device, and return key to the Substation Operations Supervisor, System Operator, or designated storage location in the Telecom Room or other unmanned location.

5. System Operator will make an entry in the Switching Center Log stating the reason the anti-tailgate device was disabled and contact name at Corporate Security.

6. For Telecom Room or unmanned locations, the responsible employee with unescorted access will make a log entry in the NERC CIP Visitors/Incident Log stating the reason the anti-tailgate device was disabled and contact name at Corporate Security.

7. All visitors must sign in and out using the NERC CIP Visitors Log and indicate their name, the date and time of the visit, and the purpose of the visit. The escort must also sign the Visitor Log at the time the visitors are signing in. If there are multiple visitors, one entry can be made for multiple visitors. The escort is not required to sign out at the time the visitors are leaving the restricted space or area.

F. Visitors must be escorted at all times while within the NERC Restricted facility or area. Personnel escorting visitors must accompany the visitor(s) continuously with dedicated attention at all times. Additional escorts may be required depending on visitors' proximity to escort.

3.4 Alarm Incidents

A. Equipment Failure

1. Failure of equipment causes a visual strobe light alarm at the Switching Center, Telecom Room, or unmanned location and an audible alarm at Corporate Security. For a Switching Center or Telecom/unmanned location Alarm Incident Information Job Aid, refer to Attachment “A” or “B”.

2. At Switching Centers, the System Operator acknowledges the alarm, assesses the nature of the incident and provides details when contacted by Corporate Security. For Telecom rooms or unmanned locations, Corporate Security will contact the local Corporate Security representative or appropriate Switching Center System Operator for assistance in assessing the nature of the incident and provides details to Corporate Security.

3. Corporate Security will reset the alarm.

4. At Switching Centers, the System Operator will make an entry in the Switching Center Log and notify the Substation Operations Supervisor. At Telecom rooms or unmanned locations, the responsible person will make an entry in the NERC CIP Visitor/Incident Log. Log entries shall include the name of the person assessing the incident, details of the incident, and the name of the contact at Corporate Security.

B. Accidental or Inadvertent Incident

1. An Accidental or Inadvertent Incident caused by a person entering the NERC Restricted facility or area results in a visual strobe-light alarm at the Switching Center, Telecom Room, or unmanned location and an audible alarm at Corporate Security. The person causing the alarm must notify the System Operator at a manned Switching Center or Corporate Security at a Telecom Room or unmanned location. Notification details will include your name, Supervisor's name, and the reason for the alarm.

2. At Switching Centers, the System Operator acknowledges the alarm, assesses the nature of the incident and obtains the person's name and Supervisor. For Telecom rooms or unmanned locations, Corporate Security will contact the local Corporate Security representative or appropriate Switching Center System Operator who will provide the person's name and Supervisor information.

3. Corporate Security will reset the alarm.

4. At Switching Centers, the System Operator will make entry in Switching Center Log and notify the Substation Operations Supervisor. At Telecom rooms or unmanned locations, the responsible person will make an entry in the NERC CIP Visitor/Incident Log. Log entries shall include the name of the person assessing the incident, details of the incident, and the name of the contact at Corporate Security.

C. Malicious Intent **with** Corporate Security Communications at Switching Centers

1. Malicious Intent Incident causes a visual strobe light alarm at the Switching Center and an audible alarm at Corporate Security.

2. The System Operator acknowledges the alarm and is unable to obtain the person's name and Supervisor information.

3. Corporate Security will contact the System Operator who will provide the person's name and Supervisor information.

4. The System Operator will leave the phone line open, escort the person from the NERC Restricted facility or area, and communicate the final details to Corporate Security.

5. Corporate Security will reset the alarm.

6. The System Operator will make an entry in the Switching Center Log and notify the Substation Operations Supervisor and GCC per System Operating Bulletin (SOB) 12 and Appendix.

7. All reportable incidents will be investigated by the SCE IT Anti-Vulnerability Emergency Response Team (AVERT).

D. Malicious Intent **without** Corporate Security Communications, at Switching Centers

1. Malicious Intent Incident causes a visual strobe light alarm at the Switching Center and an audible alarm at Corporate Security.

2. Corporate Security is unable to contact the System Operator via phone.

3. Corporate Security is unable to contact the System Operator via 900 MHz radio.

4. Corporate Security will contact the Substation Operations Supervisor.

5. Substation Operations Supervisor is unable to contact System Operator.

6. Corporate Security will contact the local law enforcement to determine the cause of the incident.

7. Corporate Security will contact the real-time GCC dispatcher.

8. Substation Operations Supervisor will meet the local law enforcement at the front gate and escort onto property.

9. Corporate Security will reset the alarm.

10. System Operator will make entry in Switching Center Log and notify GCC per SOB 12 and Appendix.

11. All reportable incidents will be investigated by the SCE IT Anti-Vulnerability Emergency Response Team (AVERT).

E. Malicious Intent **without** Corporate Security Communications at Telecom rooms or unmanned locations

1. Malicious Intent Incident causes a visual strobe-light alarm and an audible alarm at Corporate Security.

2. Corporate Security is unable to contact the location via phone.

3. Corporate Security will contact the local Corporate Security representative or appropriate Switching Center System Operator.

4. The local Corporate Security representative will assess the onsite location or the System Operator will dispatch appropriate personnel to the location.

5. Corporate Security will contact the local law enforcement to investigate the cause of the incident.

6. Corporate Security will contact the real-time GCC dispatcher.

7. The local Corporate Security representative or dispatched Switching Center personnel will meet the local law enforcement at the front gate and escort onto property.

8. Corporate Security will reset the alarm.

9. System Operator will make an entry in the Switching Center Log and notify GCC per System Operating Bulletin (SOB) 12 and Appendix with final details.

10. All reportable incidents will be investigated by the SCE IT Anti-Vulnerability Emergency Response Team (AVERT).

3.5 Access Order

An online Access Order will need to be submitted to request unescorted physical access or revocation of access to NERC Restricted facilities or areas. Refer to Attachment "E" for access and Attachment "F" for revocation job aids in creating Access Orders online.

3.6 Training Requirement

A. All personnel having authorized cyber access to Critical Cyber Assets must complete Corporate Information Security Awareness and NERC CIP Security training annually.

B. All personnel having authorized unescorted physical access to Critical Cyber Assets must complete Corporate Information Security Awareness, NERC CIP Security and role-based training annually.

3.7 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

Attachment A—NERC CIP Job Aids Switching Center Unescorted

ATTENTION

This is a NERC Restricted Facility. Please follow the instructions based on your authorized acces
Unescorted or Escorted (Visitor)

EMPLOYEES WITH UNESCORTED ACCESS (RED BADGE)

In the event of one of the following, please follow the instructions to ensure NERC CIP Compliance.

GAINING ACCESS WHEN…

ID Badge Readers are Inoperable

Step	Action
1	Contact a System Operator in the facility by using the intercom (A-Phone) located at the primary access door. *If no answer, go to Step 2.*
2	Contact Corporate Security by using the PAX (Ring Down) Phone, 0-0-1 *Corporate Security will remotely unlock the door.*
3	Check in with the System Operator so they may make the appropriate entry in the Switching Center Log.

ID Badge Readers are Inoperable AND you have an Authorized Key

Step	Action
1	Contact Corporate Security by using the PAX (Ring Down) Phone, 0-0-1
2	Notify Corporate Security that you are going to use an authorized key and expect to generate an alarm.
3	Check in with the System Operator so they may make the appropriate entry in the Switching Center Log.

Your ID Badge is not working OR you forgot your ID Badge

Step	Action
1	Contact a System Operator in the facility by using the intercom (A-Phone) located at the primary access door. *A will need to disable the anti-tailgating device. The escort will open the door and allow entry into the NERC Restr facility or area.*
2	Close the door, so the escort can activate the anti-tailgating device.
3	Escort and person must sign the NERC Visitor Log, but escort is not required to continue escort duties.

KEEPING ACCESS POINTS OPEN FOR AN EXTENDED PERIOD…

Primary or Secondary Entrances

Step	Action
1	Notify Corporate Security of intent to disable the anti-tailgating device and prop door open.
2	Turn off the anti-tailgating device with key from the Substation Operations Supervisor (SOS) or System Operatio
3	Hold open the access door. *The door must be under direct observation at all times while the door is open.*
4	When delivery is complete, close the door, turn on anti-tailgating device, and return the key to the SOS or SO.
5	Check in with System Operator so an appropriate entry can be made in the Switching Center Log indicating that tailgating device was disabled and the reason.

Basement or Roof Hatches, Emergency Exits located in NERC Restricted Areas

Step	Action
1	Contact Corporate Security of intent to prop door open.
2	Hold open the access door. *The door must be under direct observation at all times while the door is open.*
3	When delivery is complete, close the door and notify Corporate Security that the work is complete.
4	Check in with System Operator so an appropriate entry can be made in the Switching Center Log that the acces

OBSOLETE

ATTENTION

This is a NERC Restricted Facility. Please follow the instructions based on your authorized acce
Unescorted or Escorted (Visitor)

ALARM INCIDENTS

Equipment Failure Activates Alarm

Step	Action
1	The System Operator acknowledges the strobe (will turn off the strobe) and assesses the nature of the inciden
2	Corporate Security will contact the System Operator.
3	The System Operator will provide incident details – Corporate Security will reset the alarm.
4	The System Operator will make an entry into the Switching Center log and notify the SOS by email or page. N call is necessary.

Accidental or Inadvertent Incident Activates Alarm

Step	Action
1	The System Operator acknowledges the strobe (will turn off the strobe) and obtains the name of the individual off the alarm, and their supervisor's name.
2	Corporate Security will contact the System Operator.
3	The System Operator will provide the individual's name and supervisor information – Corporate Security will re alarm.
4	The System Operator will make an entry into the Switching Center log and notify the SOS by email or page. N call is necessary.

An Individual with Malicious Intent Activates Alarm AND the System Operator (SO) is able to communicate with Security

Step	Action
1	The alarm is activated - The System Operator acknowledges the strobe (will turn off the strobe) and will obtain person's name and their supervisor's name
2	Corporate Security will contact the System Operator (the System Operator will leave the phone line open)
3	The System Operator will provide the person's name and supervisor information
4	Then escort the individual from the NERC Restricted facility or area
5	Communicate the final details to Corporate Security
6	Corporate Security will reset the alarm.
7	The System Operator will make an entry into the Switching Center log and notify the SOS and GCC by Phone.

An Individual with Malicious Intent Activates Alarm AND the System Operator (SO) is NOT able to communicate Corporate Security.
If the SO is unable to respond to the alarm or phone call from Corporate Security, the following steps will take place.

Step	Action
1	Corporate Security will contact the SO via 900mHz radio.
2	If unsuccessful, Corporate Security will contact the Substation Operations Supervisor.
3	The Substation Operations Supervisor will contact the System Operator.
4	If unsuccessful, Corporate Security will contact local law enforcement and the GCC dispatcher.
5	The SOS will meet local law enforcement at the gate and escort them onto property.
6	Corporate Security will reset the alarm.
7	The System Operator will make an entry into the Switching Center log and notify the GCC by Phone. Provide information to the GCC per SOB 12 Appendix (Sabotage and Terrorism).

OBSOLETE

Attachment B—NERC CIP Job Aids Telecom Rooms Unescorted

ATTENTION

This is a NERC Restricted Facility. Please follow the instructions based on your authorized access lev
Unescorted or Escorted (Visitor)

EMPLOYEES WITH UNESCORTED ACCESS (RED BADGE) TO TELECOM ROOMS OR UNMANNED STATIONS

In the event of one of the following, please follow the instructions to ensure NERC CIP Compliance.

GAINING ACCESS WHEN…

ID Badge Readers are Inoperable

Step	Action
1	Contact Corporate Security *Corporate Security will remotely unlock the door.*
2	Make the appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log.

ID Badge Readers are Inoperable AND you have an Authorized Key

Step	Action
1	Contact Corporate Security
2	Notify Corporate Security that you are going to use an authorized key and expect to generate an alarm.
3	Make the appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log.

Your ID Badge is not working OR you forgot your ID Badge

Step	Action
1	Contact Corporate Security *Corporate Security will remotely unlock the door; or notify Corporate Security that you are going to use an authorized key and expect to generate an alarm.*
2	Make the appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log.

KEEPING ACCESS POINTS OPEN FOR AN EXTENDED PERIOD…

Primary or Secondary Entrances

Step	Action
1	Notify Corporate Security of intent to disable the anti-tailgating device and prop door open.
2	Turn off the anti-tailgating device with key from inside Telecom room door.
3	Hold open the access door. *The door must be under direct observation at all times while the door is open.*
4	When delivery is complete, close the door, turn on anti-tailgating device, and return the key to storage place.
5	Make appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log stating that the anti tailgating device was disabled and the reason.

Basement or Roof Hatches, Emergency Exits located in NERC Restricted Areas

Step	Action
1	Contact Corporate Security of intent to prop door open.
2	Hold open the access door. *The door must be under direct observation at all times while the door is open.*
3	When delivery is complete, close the door and notify Corporate Security that the work is complete.
4	Make appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log stating that the access point was open for an extended period of time.

OBSOLETE

ATTENTION

This is a NERC Restricted Facility. Please follow the instructions based on your authorized access l
Unescorted or Escorted (Visitor)

ALARM INCIDENTS

Equipment Failure Activates Alarm

Step	Action
1	Corporate Security will contact the Telecom Room or unmanned location PAX phone.
2	Personnel entering Telecom room or unmanned location will provide their name and supervisor information – Corpo Security will reset the alarm.
3	Make the appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log.

Accidental or Inadvertent Incident Activates Alarm

Step	Action
1	Corporate Security will contact the Telecom Room or unmanned location PAX phone.
2	Personnel entering Telecom room or unmanned location will provide their name and supervisor information – Corpo Security will reset the alarm.
3	Make the appropriate entry in the NERC CIP Telecom Room Log or unmanned location NERC CIP log.

Attachment C—NERC CIP Job Aids Escorted

authorized access level – Unescorted or Escorted (Visitor)

INDIVIDUALS WITH ESCORTED ACCESS (VISITORS)

While in the NERC CIP restricted area, please review and adhere to t
requirements below to ensure compliance to the NERC CIP standard

- Sign the NERC Visitor Log, including:
  - Your name
  - The date and time
  - The purpose of your visit
  - Escorts will sign the visitor log at time of visitor entry
  - Note: One escort signature may be used for multiple visito
- All visitors must be escorted by an individual who has "Unescort Access" (a Red Badge) continuously, with dedicated attention, w the NERC Restricted area.
- When leaving the NERC Restricted area, sign out on the NERC Log.
- Note: the escort is not required to sign out.

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Attachment D—NERC CIP Job Aids Telecom Rooms Escorted

ISITOR PROCEDURES – ESCORT REQUIRED

/hile in the NERC CIP Telecom or Unmanned station secure area, please eview and adhere to the requirements below to ensure compliance to the ERC CIP standards.

- Visitors must sign the NERC CIP Telecom Room or Unmanned Station NERC CIP Visitor/Incident Log, including:
  - Visitor first and last name
  - The date and time
  - The purpose of the visit
  - Escort that will accompany visitor must sign Log

- All visitors must be escorted, at all times, by an individual who has "Unescorted Access" (a Red Badge), while in the NERC Restricted areas.

- Visitors will be escorted continuously with dedicated attention while in the restricted area.

- When leaving the NERC Restricted area, the visitor will sign out on the NERC CIP Telecom Room or Unmanned station Visitor/Incident Log.

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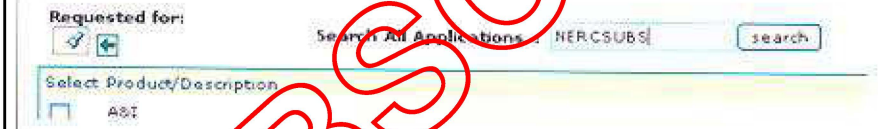
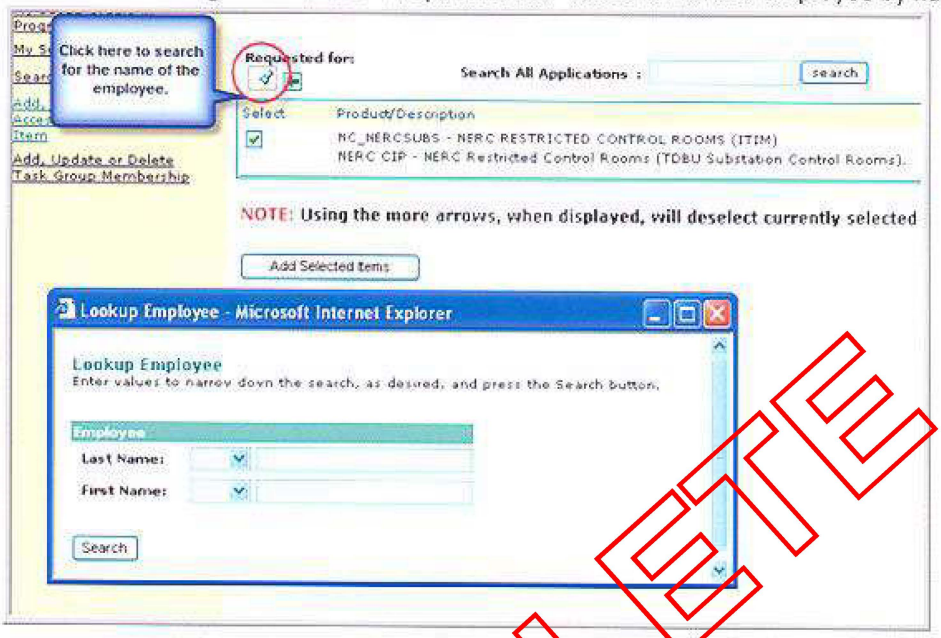
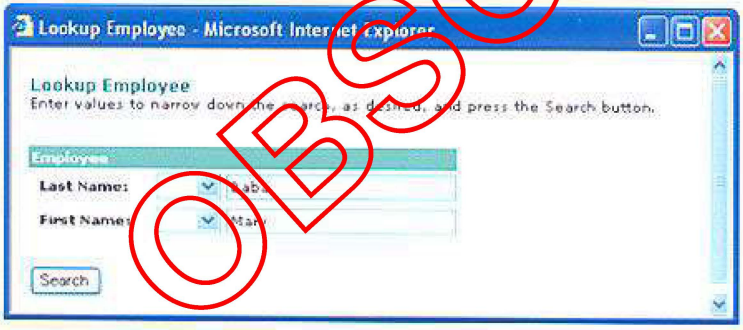
Attachment E—Submit NERC Access Order Request

date.

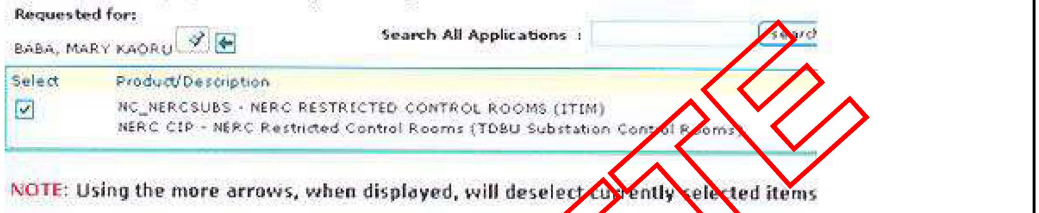
n the hiring manager is notified and given the start date by Staffing, the hiring ager should submit an Access Order Request for the employee.

Action
Go to the Portal Home Page and from the Portal Quick Links menu on the right side of the page, under the category of IT Support, select **IT Order IDs and Access**. *Order IDs & Access screen will display.*
Go to **Click here to go to Access Orders.** *The Access Ordering System window will display.*
Click on **Access Orders.** *A new menu will display.*
Click on **General Applications.** *Your cursor will appear in the "search" box.*
In the Search box, type in **NERCSUBS.** 
Click on the "Search" button *The following Product/Description will appear.* 

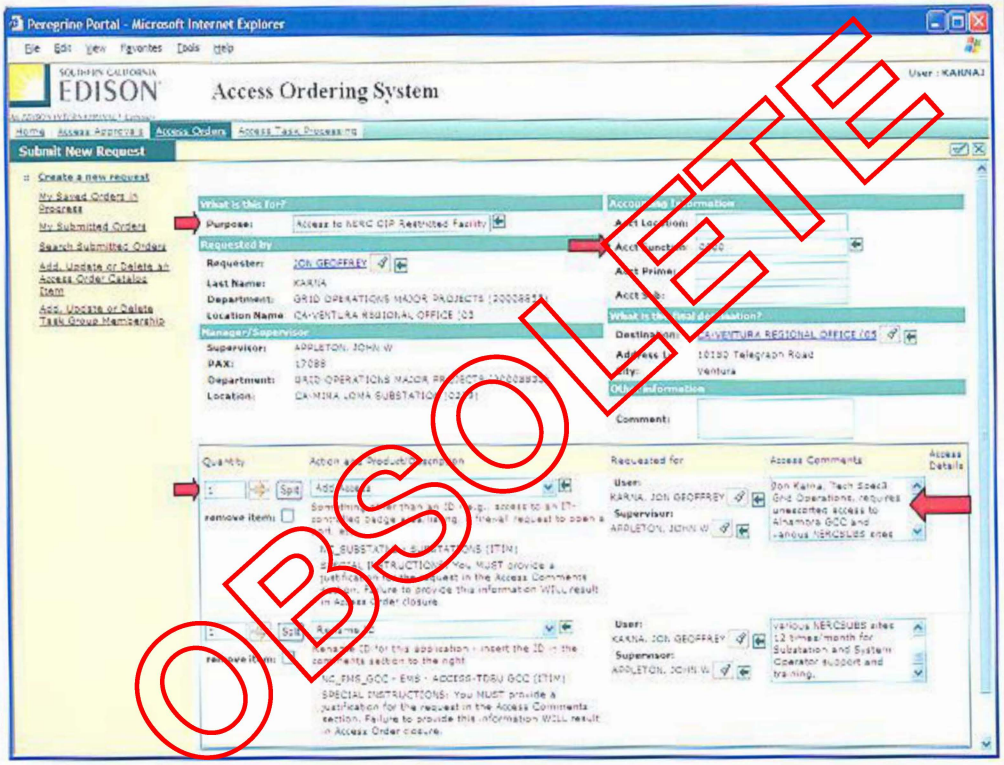
NERC CIP - Submitting Access Order Request Job Aid

Step	Action
7.	Click on the flashlight icon under "Requested For" to search for the employee by name.  *A search window will pop up.*
8.	Enter the Last Name and First Name into the appropriate boxes then click on the Search button.  *The information of the employee should appear.*

NERC CIP - Submitting Access Order Request Job Aid

Step	Action
9.	Click on the Last Name of the employee. **Lookup Employee** Click an item on the result table.  Last Name / First Name / PAW / Base Id / Department / Location / Supervisor BABA, MARY KAORU / 28741 / BABAMK / ENG DEVELOP & ENTERPRISE TRNG (20006763) / CA-GENERAL OFFICE #3 (0041) / OTOIDE, ANN N New Search Go Back *The name will populate **Requested for:***  Requested for: BABA, MARY KAORU Search All Applications : Select / Product/Description NC_NERCSUBS - NERC RESTRICTED CONTROL ROOMS (ITIM) NERC CIP - NERC Restricted Control Rooms (TDBU Substation Control Rooms) NOTE: Using the more arrows, when displayed, will deselect currently selected items
10.	Click on the Add button on the right of the screen.  Requested for: BABA, MARY KAORU Search All Applications : Search To Shopping Cart To Catalog Start Select / Product/Description NC_NERCSUBS - NERC RESTRICTED CONTROL ROOMS (ITIM) NERC CIP - NERC Restricted Control Rooms (TDBU Substation Control Rooms) Add To Shopping Cart To Catalog Start NOTE: Using the more arrows, when displayed, will deselect currently selected items. *A new screen will appear.*

NERC CIP - Submitting Access Order Request Job Aid

Step	Action
11.	Confirm the Requested by and Manager/Supervisor information is correct and fill out the fields below with the following information (see arrows below): **Purpose:** Access to NERC Restricted Facility **Acct Function:** 0000 **Action and Product/Description:** from the Drop Down Menu, select Add Access **Access Comments:** Enter a brief description of the applicant's job title and duties as pertains to the NERC CIP Access being requested. For Physical Access, include the approximate frequency (daily, or times per week/month) the access will be needed. Example: *Jon Karna, Tech Spec 3 Grid Operations, requires unescorted access to various NERCSUBS sites and Alhambra GCC 12 times/month for Substation and System Operator systems support and training.* 
12.	After all required fields are completed, click on **Submit.** • *A request number will be issued, please write this number down and keep it for future reference.* • *The Access Order System will route the request to the Access Order Request Coordinator/Approver.* • *As the requester, you will receive notification from Peregrin that the request has been submitted.* • *As the requester, you will receive notification once the request has been approved or*

Attachment F—Revoking NERC-CIP Access Manager

Revoking NERC-CIP Access

Revoking Access to CCAs Job Aid

NERC CIP standards clearly state that access to Critical Cyber Asset (CCAs must be revoked **24 hours** when personnel have been terminated for cause, and within **7 days** for personne no longer require access to CCAs. The manager is responsible for initiating the access revo process.

Once a termination or transfer occurs, the manager must determine whether the employe CCA access and/or information access which must be revoked.

Revoking Access within 24 Hours

Step	Action
4.1	Perform tasks identified in TDBU Termination Checklist found in Portal. Link listed below..
4.2	Notify Manager of IT PSC (x46545) and Corporate Security (x27878) of employee termination and request revocation of all system access within 24 hours
4.3	Capture evidence of employee termination effective date/time from SAP/HCM and provide to Manager of IT PSC
4.4	Monitor status of access to ensure completion with 24 hours

Paste link below in Portal browser:
https://portal.edisonintl.com/irj/go/km/docs/sce/TDBU/Business%20Area/Tools%20an sources/Tools%20and%20Resources%20overview/TDBU%20Tools%20and%20Resources %20U/Termination%20Checklist%20-%20TDBU.pdf

Revoking Access within 7 Days

Step	Action
4.5	Perform tasks identified in Attachment "Submit Access Order Request" and at step 11, choose "Delete ID" in the drop-down list at the bottom left of the screen for the category item selected. **Note: this will remove access for the selected category only.**
4.6	Monitor status of access to ensure completion within 7 days

RC3: NERC Cyber Asset Change Management Policy

1.0 General

This policy is intended to support SCE's compliance with the NERC Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers, human machine interfaces, etc. The purpose of the NERC Cyber Asset Change Management Policy is to reduce the risk of unauthorized activities associated to inspections, installations, removals, and modifications of applicable Cyber Assets on the BES.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) – A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- Impact Rating – The rating that is given to a Cyber Asset as it relates to its impact to the Bulk Electric System per NERC CIP-002-5 Attachment 1 Criteria.
- Protected Cyber Asset (PCA) – One of more Cyber Assets connected on a network using routable protocol within an Electronic Security Perimeter (ESP). The Protected Cyber Assets must be protected to the extent that the highest rated BES Cyber System in the same ESP.

3.0 Emergencies

This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of BES Cyber Systems and their associated Protected Cyber Assets per a CIP Exceptional Circumstance. See SOM RC9: NERC CIP Exceptional Circumstances Policy for more information.

4.0 Applicability

This policy applies to Cyber Assets which are considered Medium Impact BES Cyber Assets or Protected Cyber Assets at their associated BES substation.[1/]

5.0 Responsibility

5.1 Test Personnel

Compliance with this policy is the responsibility of SC&M Test personnel. Contract Test Technicians also shall comply with this policy.

[1/] Medium Impact BES Cyber Assets or Protected Cyber Assets can be identified using the Test Smart Form Tool's (TSFT's) "View SAP Inventory" selection. Typically, Medium Impact BES Cyber Systems are associated to 500 kV, most 220 kV substations, and many Remedial Action Scheme (RAS) and Under Frequency Load Shedding (UFLS) equipment. Protected Cyber Assets are associated to Medium Impact BES Cyber Systems that are on the same SA-2 network.

5.2 Maintenance Personnel

SC&M Maintenance personnel are occasionally involved for synchronous controller units associated to circuit breakers and BES load tap changer controllers. Maintenance personnel should contact the SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274-1700 for guidance on change management of these devices.

6.0 Policy Statements

6.1 NERC Cyber Asset Change Management is composed of the following required activities that are mandatory at substations housing Medium Impact BES Cyber Assets or Protected Cyber Assets (PCAs):

A. Use the Test Smart Form Tool (TSFT) which is loaded on SCE issued TCA prior to in servicing equipment each time a Test Crew performs inspection/maintenance, installations, removals, or modifications to applicable Medium Impact BES Cyber Assets or Protected Cyber Assets.

B. A Request for Change (RFC) number is required for demonstrating approval from T&D Change Approval Board. If you do not have an RFC number, contact SC&M Regulatory Compliance (SC&M) Hotline Number (909) 274-1700.

C. Completion of all NERC CIP Activities when applicable equipment (such as a protective relay) has an equipment outage. Examples would be port scans and conformance to NERC CIP password requirements. See SOM RC-5: System Access Control for more information about password requirements.

D. Prior to replacing any BES Cyber Asset or Protected Cyber Asset that fails in the field, Incident Response activities are required on the failed equipment that after removal can potentially be powered up and accept commands. See SOM RC-6: Incident Response for more information.

E. Completion of BES Cyber Asset or Protected Cyber Asset Removal/Disposal activities such as restoring a Cyber Asset to default settings or using the NERC CIP Cyber Asset Chain of Custody Form for failed Cyber Assets that are unresponsive or where their default settings cannot be removed. See SOM RC-8: Information Protection for more information.

6.2 Contact the SC&M Regulatory Compliance (SC&M RC) Hotline Number (909) 274-1700 for guidance on change management.

6.3 For detailed information regarding NERC CIP Cyber Asset Change Management such as inspection and maintenance, installation, disposal and removal, and modifications, please refer to the NERC CIP Requirements in the SC&M Maintenance & Inspection Manual (MIM) for specific details.

6.4 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

RC4: NERC Malicious Code Prevention Policy

1.0 General

This policy is intended to support SCE's compliance with the North American Electric Reliability Corporation (NERC) Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers, human machine interfaces, etc. The purpose of the NERC Malicious Code Prevention Policy is to implement measures to deter, detect, or prevent malicious code from being introduced into our environment.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) - A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- Impact Rating - The rating that is given to a Cyber Asset as it relates to its impact to the Bulk Electric System per NERC CIP-002-5 Attachment 1 Criteria.
- Protected Cyber Asset (PCA) - One of more Cyber Assets connected on a network using routable protocol within an Electronic Security Perimeter (ESP). The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

3.0 Emergencies

This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of BES Cyber Systems and their associated Protected Cyber Assets per a CIP Exceptional Circumstance. See SOM RC9: NERC CIP Exceptional Circumstances Policy for more information.

4.0 Applicability

This policy applies to equipment such as laptops or portable media (e.g., USB drives) which may be connected to Medium Impact BES Cyber Assets or Protected Cyber Assets at their associated BES substation.[1/]

5.0 Responsibility

Compliance with this policy is the responsibility of SC&M Test personnel. Contract Test Technicians also shall comply with this policy.

[1/] Medium Impact BES Cyber Assets or Protected Cyber Assets can be identified using the Test Smart Form Tool's (TSFT's) "View SAP Inventory" selection. Typically, Medium Impact BES Cyber Systems are associated to 500 kV, most 220 kV substations, and many Remedial Action Scheme (RAS) and Under Frequency Load Shedding (UFLS) equipment. Protected Cyber Assets are associated to Medium Impact BES Cyber Systems that are on the same SA-2 network.

6.0 Policy Statements

6.1 All laptop computers, tablets or other controlling devices that are allowed to connect to BES Cyber Systems/Protected Cyber Assets must be disconnected from wired or wireless (wireless connections are defined as WiFi, Bluetooth or any other non-wired connection) networks prior and during the BES Cyber System and/or Protected Cyber Asset connection. SCE- issued laptops have wireless connectivity disabled to ensure they are free of malicious code. This effort ensures that no malware is introduced to the laptop and transmitted to the connected in-scope Cyber Asset.

6.2 Users are required to connect their SCE-issued laptops to the SCE Admin network periodically (at least once every 7 days for at least 4 hours) to ensure that IT processes (e.g., virus scanning, security patches, etc.) can be executed in the background. This effort will ensure that plugged in portable media will not transfer malicious code to associated Cyber Assets.

6.3 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

RC5: NERC System Access Control Policy

1.0 General

This policy is intended to support SCE's compliance with the NERC Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers (PLC), human machine interfaces (HMI), etc. The purpose of the NERC System Access Control Policy is to manage system security by specifying select technical, operational, and procedural requirements in support of protecting applicable Cyber Assets on the BES against compromise that could lead to misoperation or instability of the BES. Primarily this policy applies to passwords used on applicable Cyber Assets.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) - A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- Impact Rating - The rating that is given to a Cyber Asset as it relates to its impact to the Bulk Electric System per NERC CIP-002-5 Attachment 1 Criteria.
- Protected Cyber Asset (PCA) - One of more Cyber Assets connected on a network using routable protocol within an Electronic Security Perimeter (ESP). The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

3.0 Emergencies

This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of BES Cyber Systems and their associated Protected Cyber Assets per a CIP Exceptional Circumstance. See SOM RC9: NERC CIP Exceptional Circumstances Policy for more information.

4.0 Applicability

This policy applies to equipment such as laptops or USB drives which may be connected to Medium Impact BES Cyber Assets or Protected Cyber Assets at their associated BES substation. [1/]

[1/] Medium Impact BES Cyber Assets or Protected Cyber Assets can be identified using the Test Smart Form Tool's (TSFT's) "View SAP Inventory" selection. Typically, Medium Impact BES Cyber Systems are associated to 500 kV, most 220 kV substations, and many Remedial Action Scheme (RAS) and Under Frequency Load Shedding (UFLS) equipment. Protected Cyber Assets are associated to Medium Impact BES Cyber Systems that are on the same SA-2 network.

5.0 Responsibility

5.1 Test Personnel

Compliance with this policy is the responsibility of SC&M Test personnel. Contract Test Technicians also shall comply with this policy.

5.2 Maintenance Personnel

Compliance with this policy is the responsibility of SC&M Maintenance personnel.

5.3 Substation Operator Personnel

Compliance with this policy is the responsibility of Grid Operations Substation Operator personnel.

5.4 Policy Statements

5.5 SC&M Test Technicians must remove default passwords where applicable on newly installed Medium Impact BES Cyber Systems and/or Protected Cyber Assets.

5.6 SC&M Test Technicians must utilize passwords where applicable on newly installed Medium Impact BES Cyber Systems and/or Protected Cyber Assets that meet the following requirements:

A. Installed password must meet length requirement[2/] which states: Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset;

B. Installed password must meet complexity requirement[3/] which states: Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, nonalphanumeric) or the maximum complexity supported by the Cyber Asset.

An exception exists for GE UR relays with SA-2 automation or connected serially to an RTU (i.e., "Direct RTU" relay). Contact the SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274 -1700 for clarification if required.

5.7 If required, Test, Maintenance, and Grid Ops applicable personnel may retrieve passwords by using the Test Smart Form Tool (TSFT). Please note that per the exception identified in 6.2, some GE UR relays with SA-2 automation or connected serially to an RTU (i.e., "Direct RTU" relay) will not require a password. Personnel will know that a password is required when prompted by the Cyber Asset to perform a function.

5.8 Passwords shall not be written down. See SOM RC-8: North American Electric Reliability Corporation (NERC) Information Protection Policy for more information.

5.9 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

[2/] Per NERC CIP Standard CIP-007-6 R5.5.1

[3/] Per NERC CIP Standard CIP-007-6 R5.5.2

RC6: NERC Incident Response Policy

1.0 General

This policy is intended to support SCE's compliance with the NERC Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers, human machine interfaces, etc. The purpose of the Incident Response Policy is to identify, classify and respond to Cyber security related incidents, and to minimize loss and destruction to T&D Managed BES Cyber Systems.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) - A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- Impact Rating - The rating that is given to a Cyber Asset as it relates to its impact to the Bulk Electric System per NERC CIP-002-5 Attachment 1 Criteria.
- Protected Cyber Asset (PCA) - One of more Cyber Assets connected on a network using routable protocol within an Electronic Security Perimeter (ESP). The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

3.0 Emergencies

This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of BES Cyber Systems and their associated Protected Cyber Assets per a CIP Exceptional Circumstance. See SOM RC9: NERC CIP Exceptional Circumstances Policy for more information.

4.0 Applicability

This policy applies to Cyber Assets which are considered Medium Impact BES Cyber Assets or Protected Cyber Assets at their associated BES substation.[1/]

[1/] Medium Impact BES Cyber Assets or Protected Cyber Assets can be identified using the Test Smart Form Tool's (TSFT's) “View SAP Inventory” selection. Typically, Medium Impact BES Cyber Systems are associated to 500 kV, most 220 kV substations, and many Remedial Action Scheme (RAS) and Under Frequency Load Shedding (UFLS) equipment. Protected Cyber Assets are associated to Medium Impact BES Cyber Systems that are on the same SA-2 network.

5.0 Responsibility

5.1 Test Personnel

Compliance with this policy is the responsibility of SC&M Test personnel. Contract Test Technicians also shall comply with this policy.

5.2 Maintenance Personnel

Compliance with this policy is the responsibility of SC&M Maintenance personnel.

5.3 Substation Operator Personnel

Compliance with this policy is the responsibility of Grid Operations Substation Operator personnel.

6.0 Policy Statements

This policy applies to a NERC CIP Bulk Electric System (BES) Facility. If you are working on operational or maintenance activities, be alert to the possibility of a cybersecurity incident.

6.1 Ask yourself these questions:

A. Are there any signs of unauthorized or forced entry into the facility (fences, doors, cabinets)?

B. Are there any signs of abnormal cyber asset behavior (erroneous breaker operation which cannot be validated, Cyber Asset sending false data, etc.)?

C. Are there any devices (USB drives, devices plugged into network ports, etc.) that appear out of place?

6.2 If you answer "Yes" to any of these questions, do the following:

A. Test Technicians follow the Test Smart Form Tool (TSFT) process during cyber asset replacement/removal to complete the 'Preliminary Incident Response" check sheet.

B. Other personnel contact SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274-1700.

6.3 Before making any changes to Cyber Assets, follow the related NERC CIP Change Management procedures.

6.4 If a cybersecurity incident is suspected, do not make any changes to a failed Cyber Asset or attempt to reinstall/reuse the Cyber Asset.

6.5 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

Please refer to the NERC CIP Requirements in the SC&M Maintenance & Inspection Manual (MIM) for specific details.

RC7: NERC System Recovery Policy

1.0 General

This policy is intended to support SCE's compliance with the North American Electric Reliability Corporation (NERC) Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers (PLC), human machine interfaces (HMI), etc. The purpose of the NERC System Recovery Policy is to recover reliability functions on T&D managed BES Cyber Systems (BCS) in accordance with NERC CIP Standards.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) - A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- Impact Rating - The rating that is given to a Cyber Asset as it relates to its impact to the Bulk Electric System per NERC CIP-002-5 Attachment 1 Criteria.
- Protected Cyber Asset (PCA) - One of more Cyber Assets connected on a network using routable protocol within an Electronic Security Perimeter (ESP). The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

3.0 Emergencies

This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of BES Cyber Systems and their associated Protected Cyber Assets per a CIP Exceptional Circumstance. See SOM RC9: NERC CIP Exceptional Circumstances Policy for more information.

4.0 Applicability

This policy applies to equipment such as laptops or USB drives which may be connected to Medium Impact BES Cyber Assets or Protected Cyber Assets at their associated BES substation[1/]

[1/] Medium Impact BES Cyber Assets or Protected Cyber Assets can be identified using the Test Smart Form Tool's (TSFT's) “View SAP Inventory” selection. Typically, Medium Impact BES Cyber Systems are associated to 500 kV, most 220 kV substations, and many Remedial Action Scheme (RAS) and Under Frequency Load Shedding (UFLS) equipment. Protected Cyber Assets are associated to Medium Impact BES Cyber Systems that are on the same SA-2 network.

5.0 Responsibility

5.1 Test Personnel

Compliance with this policy is the responsibility of SC&M Test personnel. Contract Test Technicians also shall comply with this policy.

5.2 Maintenance Personnel

SC&M Maintenance personnel are occasionally involved for synchronous controller units associated to circuit breakers and BES load tap changer controllers. Maintenance personnel should contact the SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274-1700 for guidance on change management of these devices.

6.0 Policy Statements

6.1 The Recovery Plan applies to the following Cyber Assets:

A. Gateways

B. Human Machine Interfaces (HMI)

C. Managed Switches

D. Meters

E. PLCs

F. PMUs

G. Relays

H. Synchronous Control Units (SCU)

I. Terminal Servers

6.2 In the event a BES Cyber Asset or Protected Cyber Asset fails, Test Technicians must follow the Test Smart Form Tool (TSFT) process during cyber asset replacement/removal to complete the "Preliminary Incident Response" check sheet:

A. If a cybersecurity incident is suspected, do not make any changes to a failed Cyber Asset or attempt to reinstall/reuse the Cyber Asset and follow the instructions from the TSFT process. See SOM RC-6: North American Electric Reliability Corporation (NERC) CIP Incident Response Policy for more information.

B. If a cybersecurity incident is not suspected, a NERC CIP Recovery Plan shall be initiated. This NERC CIP Recovery Plan contains steps required for the recovery of the BES Cyber Asset or Protected Cyber Asset through identification of points of contacts, configuration file locations, installation/commissioning instructions (which refers to the SC&M Maintenance & Inspection Manual (MIM), etc.).

6.3 Test Technicians must contact the SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274-1700 to report a suspected cyber security incident and/or seek support with NERC CIP Recovery Plans. Additionally, Test Technicians may contact SC&M TS&S Relay/Test or TS&S Automation (the specific group is based on the applicable Cyber Asset) for installation/commissioning support.

6.4 Before making any changes to Cyber Assets, follow the related NERC CIP Change Management procedures referenced in the NERC CIP Requirements in the SC&M Maintenance & Inspection Manual (MIM).

6.5 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

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RC8: NERC Information Protection Policy

1.0 General

This policy is intended to support SCE's compliance with the North American Electric Reliability Corporation (NERC) Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers, human machine interfaces, etc. The purpose of this policy is to prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting T&D managed BES Cyber Systems (BCS) against compromise that could lead to misoperation or instability in the BES.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) - A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- BES Cyber System Information (BESCSI) - Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System. BESCSI is sometimes known as NERC CIP Protected Information.
- Impact Rating - The rating that is given to a Cyber Asset as it relates to its impact to the Bulk Electric System per NERC CIP-002-5 Attachment 1 Criteria.
- Protected Cyber Asset (PCA) - One of more Cyber Assets connected on a network using routable protocol within an Electronic Security Perimeter (ESP). The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

3.0 Emergencies

This policy may be temporarily suspended if required to allow effective response to, or recovery from, an event or condition of sufficient duration and severity to result in a significant impact to the operation or support of BES Cyber Systems and their associated Protected Cyber Assets per a CIP Exceptional Circumstance. See SOM RC9: NERC CIP Exceptional Circumstances Policy for more information.

4.0 Applicability

This policy applies to equipment such as laptops or USB drives which may be connected to Medium Impact BES Cyber Assets or Protected Cyber Assets at their associated BES substation[1/]

5.0 Responsibility

This policy applies to the Organizational Units (OU) and Business Lines impacted by any of the NERC CIP Reliability Standards, including, but not limited to:

- Substation Construction and Maintenance
- Grid Operations

6.0 Policy Statements

This policy specifically applies to BES Cyber Assets or Protected Cyber Assets which contain BESCSI, their storage, security during transit, and actions used to prevent unauthorized retrieval of BES Cyber System Information.

6.1 Identification of BESCSI

The following items with context (i.e., information that can be used to identify the specific BCA/PCA such as SAP Equipment Number, Equipment Description, Substation name, etc.) associated with a BES Cyber Asset is considered applicable to this policy:

A. Individual Pieces of Information

1. IP Addresses associated to CRAS, Phasor, or SA-3 Substation Automation
2. Passwords
3. System Recovery Plans

B. Repositories

1. Applicable NERC CIP SharePoint(s)
2. Aspen Relay Database
3. Protection Suite
4. SAP Master Data
5. TDBU26 ELAN Shared Drive
6. Test Smart Form Tool (TSFT) and associated TDBU1 TSFT Shared Drive
7. TDBU1 SAS point list

[1/] Medium Impact BES Cyber Assets or Protected Cyber Assets can be identified using the Test Smart Form Tool's (TSFT's) "View SAP Inventory" selection. Typically, Medium Impact BES Cyber Systems are associated to 500 kV, most 220 kV substations, and many Remedial Action Scheme (RAS) and Under Frequency Load Shedding (UFLS) equipment. Protected Cyber Assets are associated to Medium Impact BES Cyber Systems that are on the same SA-2 network.

8. TDBU2 SAS point list

6.2 Handling of BESCSI

BESCSI is subject to strict controls. Users of BESCSI data must adhere to the following guidelines:

A. BESCSI cannot be shared with unauthorized personnel.

B. BESCSI cannot be sent over email as an attachment. Authorized personnel should refer to the BESCSI Data Repository to retrieve the applicable information. Otherwise, SharePoint sites can be used for collaboration with authorized personnel that also have access to the SharePoint.

C. BESCSI must only be used as required for the performance of job duties.

D. Physical documents that contain BESCSI are not to be left unattended while in use. Appropriate protections (i.e., locked in a cabinet or other location) must be in place when not in use. Preference should be to maintain electronic copies of BESCSI versus physical copies of BESCSI.

E. BESCSI shall be returned, shredded, or electronically destroyed when no longer needed or when requested by the Information Owner.

F. Users are responsible for identifying new BESCSI and applying the appropriate protections until the information is moved to a repository.

G. If a new BESCSI document is created, the creator is responsible for protection of the documents and ensuring proper controls for handling the documents are in place while the documents are in their possession.

H. The NERC CIP Cyber Asset Chain of Custody Form must be used for Cyber Assets that are removed from the Physical Security Zone (PSZ) or Physical Security Perimeter (PSP) which is the physical location (with NERC CIP security controls such as card readers and cameras) where the Cyber Asset resides. Failed Cyber Assets that are unresponsive or where their default settings cannot be removed are sent to SC&M TS&S at Pomona Innovation Village or vendors for further analysis. Please refer to the NERC CIP Requirements in the SC&M Maintenance & Inspection Manual (MIM) for specific details.

6.3 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

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RC9: NERC CIP Exceptional Circumstances Policy

1.0 General

This policy is intended to support SCE's compliance with the NERC Reliability Critical Infrastructure Protection (CIP) Standards which apply to the protection of Cyber Assets. These Cyber Assets are programmable electronic devices that support the Bulk Electric System (BES) and include relays, programmable logic controllers, human machine interfaces, etc. The purpose of the NERC CIP Exceptional Circumstances Policy is to detail the appropriate steps in declaring, assessing, and terminating a CIP Exceptional Circumstance. A CIP Exceptional Circumstance allows for a suspension of NERC CIP policies, processes, and procedures (i.e., bypass card readers and/or anti-tailgating devices, modify Cyber Assets without RFCs, etc.) in various instances. See Attachment A for instances of CIP Exceptional Circumstances.

2.0 Definitions

Definitions are modified versions adapted from the NERC Glossary of Terms.

- BES Cyber Asset (BCA)/BES Cyber System (BCS) – A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one of more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Also known as a BES Cyber System which is defined as one or more BES Cyber Assets logically grouped to perform one or more reliability tasks is considered a BES Cyber System.
- CIP Exceptional Circumstance – A situation that involves or threatens to involve one or more of the following, or any similar conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability. See Attachment A for instances of CIP Exceptional Circumstances.

3.0 Applicability

This policy applies to the Organizational Units (OU) and Business Lines impacted by any of the NERC CIP Reliability Standards, including, but not limited to:

- Substation Construction and Maintenance
- Grid Operations

4.0 Roles and Responsibilites

4.1 CIP Exceptional Circumstance Initiator

Though any SCE employee, contractor or vendor can identify and respond to a CIP Exceptional Circumstance, it is the responsibility of a senior on-site person (e.g. supervisor or manager) to officially declare or initiate a CIP Exceptional Circumstance. If the CIP Exceptional Circumstance is for an unmanned site, this role can be performed at the site where the issue has been discovered. This responsibility may be the acting operator, test supervising test technician, system operator, station chief, SC&M field S3, or field M2. The Initiator is responsible in declaring the CIP Exceptional Circumstance and contacting the SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274-1700 to provide necessary details and rationale. SC&M RC will document all relevant information to provide to external organizations.

4.2 Support Personnel

Personnel on site whom are required to respond to the CIP Exceptional Circumstance. This role can be held by additional personnel from other sites depending on the need for support.

4.3 Emergency Responder

Emergency responders are outside of SCE such as police, EMTs, and firefighters. They won't have authorization into our facilities and would need authorized unescorted physical access due to immediate emergency response from the identified CIP Exceptional Circumstance. Due to the emergency response, emergency responders must bypass SCE's NERC CIP visitor control procedure.

4.4 Primary Responder

Primary Responder include all SCE employees, contractors or vendors called on to respond directly to the CIP Exceptional Circumstance. While responders are primarily at the site, they may also be at other sites, especially when responding to a Cyber Security Incident.

4.5 CIP Exceptional Circumstance Terminator

Role is typically held by the senior person on-site. Usually is a supervisor or manager. This responsibility may be the test supervising test technician, system operator, station chief, SC&M field S3, or field M2. Once the impact has subsided and all appropriate actions has been completed, the CIP Exceptional Circumstance Terminator may end the CIP Exceptional Circumstance. When the CIP Exceptional Circumstance has ended, the terminator must notify SC&M RC who will document all relevant information to provide to external organizations.

5.0 Policy Statements

5.1 An event occurs which has significant impact to safety and/or the BES Reliability. The CIP Exceptional Circumstance Initiator assesses the alert and contacts the SC&M Regulatory Compliance (SC&M RC) Hotline Number at (909) 274-1700. See Attachment A for instances of CIP Exceptional Circumstances.

5.2 The CIP Exceptional Circumstance Initiator declares the alert and notifies the appropriate primary responder and support personnel to respond. For unmanned stations, the CIP Exceptional Circumstance Initiator can declare CIP Exceptional Circumstance on their current location.

5.3 Emergency response may already be on site of the declared CIP Exceptional Circumstance. The primary duties of support Personnel, in case of an injured or suspected impact to the BES reliability, will be to escort the Emergency responders through the facilities. In case of fire or threat to safety, the supporting personnel will be given monitoring duties in order to support the Emergency Response team.

5.4 Primary Responders and support personnel assigned will conduct appropriate action for the removal of BES Cyber Asset Information if deemed safe. Once removed, they shall place the BES Cyber Asset Information into a temporary storage container or an assigned repository.

5.5 When the impact has subsided, the CIP Exceptional Terminator shall terminate the CIP Exceptional Circumstance and contact SC&M RC who will document all relevant information to provide to external organizations.

5.6 Failure to comply with NERC Cyber Security policies and standards will be subject to disciplinary action, up to and including, termination and civil or criminal penalties as provided by law.

Attachment A - CIP Exceptional Circumstances Instances

CIP exceptional circumstances allow for a suspension of NERC CIP policies, processes, and procedures. The following are instances where CIP exceptional circumstances are applicable:

- Conditions that significantly impact safety or BES reliability
- A risk of injury or death
  - — Hazardous Material Release
  - — Loss of Hazardous Material
  - — Radiation Release
  - — Loss of Irradiated Material
  - — Fatality
  - — Injury
- A natural disaster: such as earthquake, or wildfire causing
  - — Transportation Disruption
  - — Fuel Shortage
  - — Natural Gas Shortage
  - — Electrical Grid Material Shortage
  - — Dam Severely Damaged
- Civil unrest
- An imminent or existing hardware, software, or equipment/apparatus failure
  - — 500 kV substations damaged
  - — 220 kV substations damaged
  - — 100% Customer Outage
  - — Critical Customer Outage
- A Cyber Security Incident requiring emergency assistance causing
  - — Interruption to or Loss of Network Hardware or Computing Infrastructure
- A response by emergency services
- The enactment of a mutual assistance agreement
- An impediment of large scale workforce availability
  - — 40% Employee Absenteeism
  - — Loss of Decision Making Authority
  - — Loss of Operational Communication Methods