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Purpose

The FirstEnergy (FE) Utilities' "System Performance Excellence Methodology" ("methodology") is a multi-year grid evolution program, focused on investments that delivers power our customers depend on today while also meeting the challenge of tomorrow.

Under this plan, FE is enhancing the high-voltage transmission system to help grid operators respond more swiftly to variable conditions, implementing grid management solutions, automation, and emerging technologies to help protect against power outages and minimize the impact of outages if they occur.

Our methodology will improve the health, reliability, capacity, and operational flexibility of the FE transmission system for existing and new customer loads. It is designed to:

- Fulfill the obligations of the FE companies under the PJM Regional Transmission Expansion Planning (RTEP) process.
- Upgrade condition of equipment.
- Enhance system performance.
- Improve operational flexibility.
- Improve Information Technology (IT) network infrastructure.
- Upgrade system cyber and physical security.
- Evaluate the health and inventory of the transmission system.

Applicability

Our methodology and guidelines contained within this document serve to help Transmission engineers and personnel identify potential projects and programs, to achieve the overall desired results of improving the health, reliability, capacity, and operational flexibility of the FE transmission system for existing and new customer loads. Projects are identified based on guidelines provided in one of, or multiples of, the project types described below.

Overview of the 6 Types of Projects

The sections in this document outline guidelines for six project types:

- *Section 1: System Condition Projects*
- *Section 2: System Performance Projects*
- *Section 3: Operational Flexibility Projects*
- *Section 4: Communications: Reliability, Capability, and Resilience Projects*
- *Section 5: Security Projects*
- *Section 6: Transmission Asset Health and Inventory Programs*

These project types were determined based on the unique benefit they provide to the FE transmission system. Each type plays a critical role in achieving results of our methodology.

Projects identified through the PJM RTEP process are not within the scope of this document. However, where appropriate, projects identified through the methodology and guidelines contained within this document may be submitted to PJM as Supplemental Projects.

1. System Condition Projects

Improving the health and increasing the reliability of the FE transmission system is one of the core objectives of the methodology. Strategically reviewing the present system by performing condition-based assessments is important to achieving this objective.

1.1. Substation Condition Rebuild/Replacement

The health of FE transmission facilities can be improved by rebuilding and/or replacing substation equipment where appropriate. To determine whether a substation or its assets should be rebuilt or replaced based on its condition, the following global characteristics may be considered:

- Level of criticality to system performance and operations
- Equipment installation times (long lead and/or extended)
- Negative impact on equipment health and/or system reliability
- Outage frequency and/or durations
- Increasing negative trend in maintenance findings and/or costs
- Failure risk, to the extent caused by asset design characteristics, historical industry/company performance data, or application design error.
- Limited availability of spare parts, software obsolescence and/or compatibility, or vendor technical support
- Environmental considerations
- Expected service life (at or beyond) or obsolescence
- Operation, design, or installation limitations
- Space constraints in the control enclosure or substation yard
- Manufacturing date and In-service date
- Known design deficiency
- Obsolescence

The review may also consider the following operational information, maintenance history, and ancillary equipment performance associated with the asset types listed in the Index table, summarized below and further described within this document. The lists of components and operational/maintenance history described within this document are not a fully inclusive list of considerations.

Index	Asset Type
1.1.1	Circuit Breakers and Other Fault Interrupting Devices
1.1.2	Power Transformers and (LTCs)
1.1.3	Station Service Transformers and Emergency Generators
1.1.4	Capacitor Bank Installations
1.1.5	Reactive Power Support Systems
1.1.6	Switches
1.1.7	Station DC Systems
1.1.8	Station System Protection and Controls
1.1.9	Devices Used for Panel, Telemetry, and Revenue Metering
1.1.10	Current Transformers (CTs), Control Cables, and Cable Trays
1.1.11	Carrier Sets and Associated Wave-Traps
1.1.12	Ground Grid
1.1.13	Perimeter Fencing, Station Lighting, and Other Security Technology
1.1.14	Steel Structural Components and Their Associated Foundations
1.1.15	Line Arresters
1.1.16	Riser and Connections
1.1.17	Conduits and Junction Boxes
1.1.18	Facilities
1.1.19	Meters, Transducers, and Other Measuring Devices
1.1.20	Intelligent Electronic Devices (IEDs)
1.1.21	Gas Insulated Substation (GIS) and Other Support Equipment
1.1.22	Capital tools

1.1.1. Circuit Breakers and Other Fault Interrupting Devices

The following components and operational/maintenance history may be considered to determine if circuit breakers and other fault interrupting devices should be rebuilt or replaced:

- Fault operations history
- Compressor
- Condition of interrupting media (e.g., oil, gas, etc.)
- Contact resistance
- Contact timing
- Bushings
- Insulation power factor
- On-line timing
- Operating mechanism
- Synchronous close control units
- Tank heater
- Time travel analysis
- Trip and close coils
- Include oil circuit breaker or other obsolete breaker types replacement in the scope of projects, where feasible to upgrade to newer technologies

1.1.2. Power Transformers and Load Tap Changers (LTCs)

The following components and operational/maintenance history may be considered to determine if power transformers and load tap changers should be rebuilt or replaced:

- Alarm and device testing, including thermometers, pressure devices, and nitrogen systems
- Bushings
- Core ground
- Dissolved gas analysis
- Insulation power factor
- Internal inspection of the clamping, blocking, steel core, and core/coil support structure
- Load tap changer
- Loading and fault history
- Moisture content
- Oil dielectric
- Oil screen
- Oxygen content
- Pumps/fans
- Radiators
- Surge arresters
- Total combustible gas
- Turns ratio
- Upgrade oil containment
- Oil Containment Pump
- Winding resistance
- De-energized tap changer
- Furan Testing
- Software Analytics Tools Scoring
- Frequency/severity of oil leaks

1.1.3. Station Service Transformers and Emergency Generators

The following components and operational/maintenance history may be considered to determine if station service transformers and emergency generators should be rebuilt or replaced:

- Capacity
- Engine generator and controls:
  - Battery
  - Cathodic protection testing
  - Engine coolant/heating systems
  - Transfer switch/control
  - Fuel source
- Panel boxes, associated conduits, and wiring
- Physical condition
- Throw-over scheme

1.1.4. Capacitor Bank Installations

The following components and operational/maintenance history may be considered to determine if capacitor bank installations should be rebuilt or replaced:

- Capacitor can
- Capacitor configuration
- Capacitor switching device (breaker or cap switcher)
- Control system
- Current transformers (CT)
- Neutral and series capacitance checks
- Panel boxes and wiring
- Potential transformers (PT)
- Reactors
- Unbalanced voltage conditions
- Fault history
- Structural integrity
- Bus work condition

1.1.5. Reactive Power Support Systems

The following components and operational/maintenance history may be considered to determine if reactive power support systems should be rebuilt or replaced:

- Static VAR Compensator (SVC)/Statcom:
  - Building condition
  - Capacitors
  - Control systems
  - Controller Software
  - Communications Systems
  - Reactors
  - Thyristor/IGBT switching circuit
  - Thyristor/IGBT cooling system
- Synchronous condenser:
  - Bearings and lubricating systems
  - Building condition
  - Control systems
  - Field circuit breaker
  - Hydrogen cooling system
  - Rotor
  - Stator
  - Supporting systems such as cooling pumps and heat exchangers

1.1.6. Switches

The following components and operational/maintenance history may be considered to determine if switches should be rebuilt or replaced:

- Gang-operated or motor operated switches:
  - Blade and jaw assembly
  - Control system
  - Mounting assembly
  - Operating mechanism
  - Switching capabilities (load, charging current, and parallel isolation)
  - Switch degradation
  - SCADA Radio/Cellular Communication (e.g., failure/obsolescence)
  - Load break system
- Stick-operated line and/or bus switch:
  - Blade and jaw assembly
  - Mounting assembly
  - Switching capabilities (load, charging current, and parallel isolation)
  - Switch degradation

1.1.7. Station DC Systems

The following components and operational/maintenance history may be considered to determine if station DC systems should be rebuilt or replaced:

- Batteries:
  - Capacity
  - Discharge test data
  - Electrolyte (i.e., specific gravity and excessive hydration)
  - Excess sediment
  - Impedance test data (i.e., Intercell, battery strap)
  - Jar/cell condition (i.e., container, cover, flame arrester, and seals)
  - Plate condition
  - Rack condition
  - Terminal Post
  - Consider replacement when a battery monitor is added to the battery
- Chargers:
  - AC ripple voltage and current
  - Capacity
  - Condition (i.e., damage, overheating, and excessive deterioration)
  - Control system
- Panels and wiring

1.1.8. Station System Protection and Controls

The following components and operational/maintenance history may be considered to determine if station system protection and controls should be rebuilt or replaced:

- Electromechanical relays
- Solid state relays
- Microprocessor relays:
  - Capability
  - Case
  - Control board
  - Input/output module
  - Isolation
  - Software compatibility
  - Test data

1.1.9. Devices Used for Panel, Telemetry, and Revenue Metering

The following components and operational/maintenance history may be considered to determine if panel, telemetry, and revenue metering devices should be rebuilt or replaced:

- 138 kV breakers with bushing potential devices
- Capability (i.e., accuracy, measurements, and data retention)
- Capacity
- Coupling capacitor voltage transformers (CCVTs)
- Potential transformers (PTs)
- Readability
- Transducers
- Refer to *Section 1.1.11 – Carrier Sets and Associated Wave-Traps*

1.1.10. Current Transformers (CTs), Control Cables, and Cable Trays

The following components and operational/maintenance history may be considered to determine if current transformers, control cables, and cable trays should be rebuilt or replaced:

- Cable capability (size and thermal rating)
- Cable insulation
- Cable tray loading
- Cable tray condition
- Cable trench
- Contingency exposure
- CT accuracy
- CT burden
- CT insulation
- CT ratio
- Insulation power factor

1.1.11. Carrier Sets and Associated Wave-Traps

The following components and operational/maintenance history may be considered to determine if carrier sets, and associated wave-traps should be rebuilt, replaced, expanded, or enhanced:

- Carrier set communication signals
- Carrier set spark gap
- Carrier tuning units
- Carrier tuning unit spark gap
- CCVT
- CCVT spark gap
- Coax cable
- Electrical/communication performance
- Wave trap and filter
- Replace manual check back carrier devices

1.1.12. Ground Grid/Ground Conductor

The following components and operational/maintenance history may be considered to determine if the ground grid should be rebuilt or replaced:

- Ground grid network
- Ground rods
- Point copper contact grounding devices
- Swage, cadweld, brazed, and bolted connections
- Step/touch potential issues
- Ground grid test results
- Ground settling

1.1.13. Perimeter Fencing, Station lighting, and Other Security Technology

The following components and operational/maintenance history may be considered to determine if perimeter fencing, station lighting and other security technology should be rebuilt or replaced:

- Cyber security issues and concerns
- Perimeter Fencing
  - Broken or missing barbed wire
  - Fence height
  - Gaps in fabric
  - Gate misalignment
  - Holes in fabric
  - Non-cut proof fabric
  - Personnel safety with manual gate
  - Rusted or damaged posts
- Physical security issues and concerns
  - Access control
  - Audio response
  - High-definition CCTV
  - Object oriented analytics technology
  - Thermal imaging
  - High Speed Avenues of Approach
  - Elevated topography
  - Lines of sight to critical components

- Station lighting (i.e., mercury and incandescent)
  - Illumination level
  - Obsolete technology (i.e., mercury and incandescent)
  - Additional lighting to enhance security posture
- Ground Setting

1.1.14. Steel Structural Components and Associated Foundations

The following components and operational/maintenance history may be considered to determine if steel structural components should be rebuilt or replaced:

- Concrete foundations
  - Crumbling concrete
  - Exposed or compromised rebar
- Grillage style foundations
  - Crumbling concrete
  - Exposed or compromised plate
  - Exposed or compromised steel beam
  - Rusted or damaged steel
  - Ground Setting

1.1.15. Line Arresters

The following components and operational/maintenance history may be considered to determine if line arresters should be rebuilt or replaced:

- Damaged insulation layer
- Insulation meg-ohm
- Insulation power factor
- Maximum Continuous Operating Voltage (MCOV) rating

1.1.16. Risers and Connections

The following components and operational/maintenance history may be considered to determine if risers and connections should be rebuilt or replaced:

- Conductor core/strands
- Connector
- Corrosion
- Heat damage on riser or connector
- Length
- Metal type
- Ground Setting

1.1.17. Conduits and Junction Boxes

The following components and operational/maintenance history may be considered to determine if conduits and junction boxes should be rebuilt or replaced:

- Control, power, potential transformer cables
- Current transformer cables
- Holes in conduit
- Holes in junction boxes
- Separation of conduit from junction boxes
- Temporary junction box installation
- Tripping hazards related to conduit
- Ground Setting

1.1.18. Facilities

The following components and operational/maintenance history may be considered to determine if facilities should be rebuilt or replaced:

- Access control
- Comingled/Third party equipment
- Constructability and maintenance
- Overall condition (i.e., foundation, walls, and roof)
- Physical security
- Safety and human performance
- Space constraints
- Station lighting
- HVAC
- Access roads and driveways
- Rail spurs/sidings

1.1.19. Meters, Transducers, and Other Measuring Devices

The following components and operational/maintenance history may be considered to determine if meters, transducers, and other measuring devices should be rebuilt or replaced:

- Capabilities
- Communication upgrades
- Consolidation of components
- Deteriorated transducers
- Accuracy
- Digital fault recorder (DFR)
- RTU upgrades
- Software compatibility

1.1.20. Intelligent Electronic Devices (IEDs)

The following components and operational/maintenance history may be considered to determine if intelligent electronic devices should be rebuilt or replaced:

- Controls
- Microprocessor devices
- Monitors
- Software compatibility

1.1.21. Gas Insulated Substation (GIS) and Other Support Equipment

The following components and operational/maintenance history may be considered to determine if gas insulated substation and other support equipment should be rebuilt or replaced:

- Breakers
- Bushings
- Disconnect/grounding switches
- Gas leakage
- Gas quality
- Monitoring system
- Obsolete technology
- Partial discharge
- PTs and CTs
- Support steel

1.1.22. Capital Tools

The following types of capital tools purchases are made to support the safe and reliable maintenance of the electric system. Several examples are listed below:

- Relay Test Sets
  - SF6 Gas Filling and Analysis Tools
  - Breaker Timing
  - PF Test Sets
  - Portable DGA Test Sets
  - Ground Grid Test Sets

1.2. Line Condition Rebuild/Replacement

The health of the FE transmission facilities can be improved by rebuilding and/or replacing transmission lines where appropriate.

FE will review and assess existing transmission facilities for equipment characteristics that are near or beyond their existing service life, contain components that are obsolete, or pose reliability risk to the system.

The following global characteristics may be considered to determine whether lines should be rehabbed, rebuilt, or replaced based on their age, performance, system criticality, risk and condition-based assessment:

- Unplanned outage frequency and/or durations
- Contingency risk
- Negative impact on equipment health and/or system reliability
- Increasing negative trend in maintenance findings and/or costs
- Failure risk, to the extent caused by asset design characteristics, or historical industry/company performance data.
- Operation, design, maintenance, or installation limitations
- Age/condition of wood pole transmission line crossarms, and braces may be considered for replacement beginning at 40 years of average age for a line segment.
- Must pass a hammer sound test.
- Age/condition of transmission line conductors and hardware may be considered for replacement beginning at 40 years of average age for a line segment.
- Age/condition of transmission line conductors and hardware typically replacement is considered, beginning at 40 years of average age for a line segment.
- System characteristics including lightning and grounding performance, conductor motion including overlap, insulation coordination, structural capacity needs, and future needs (e.g., fiber path, additional circuit, etc.)
- Current FE design criteria, applicable codes, and industry best practices
- Environmental factors parameter impacts
- Lack of resiliency or system-hardening attributes

When evaluating the replacement of in-service transmission line assets, the review may also consider maintenance operating experience, manufacturer and accepted industry practices, and current engineering design standards associated with the asset types listed in the Index table, summarized below and further described within this document. The lists of components and operational/maintenance history described within this document are not a fully inclusive list of considerations.

Index	Asset Type
1.2.1	Transmission Steel Tower, Wood and Steel Poles
1.2.2	Transmission Line Hardware
1.2.3	Transmission Line Switches
1.2.4	Transmission Line Conductor
1.2.5	Transmission Power Cable and Support Equipment

1.2.1. Transmission Steel Tower, Wood and Steel Poles

The following components and operational/maintenance history may be considered to determine if transmission steel towers and wood/steel poles should be rebuilt or replaced:

- Access to the structure
- Structural steel
  - Anchor bolts
  - Joints and flanges
  - Tubular steel
  - Lattice
  - Bolts/fasteners
  - Insulator attachment points
- Foundations
  - Direct embedded
  - Grillage
  - Concrete
- Weathering steel structures
  - Members
  - Material loss
  - Pack out at joints
  - Hardware
- Wood components
  - Poles
  - Phase raisers
  - C-truss reinforced
  - Pole top extensions
  - General condition and remaining strength
  - Crossarms
  - Braces
- Grounding system

1.2.2. Transmission Line Hardware

The following components and operational/maintenance history may be considered to determine if transmission line hardware should be rebuilt or replaced:

- Insulators
  - Polymer
  - Porcelain
  - Glass
  - NESC required loads for replacement insulator applications.
- Clamps
- Armor rod
- Dampeners
- Splices and/or splice shunts
- Corona rings

1.2.3. Transmission Line Switches

The following components and operational/maintenance history may be considered to determine if transmission line switches should be rebuilt or replaced:

- Accessibility
- Manually operated switches
- Motor-operated switches
- Switch configuration (e.g. high velocity whips, vacuum bottles, full load break capability)
- Switch structure (e.g. multiple wood pole configuration, 2-way or 3-way switches)
- Availability of replacement parts
- Ability to perform maintenance.
- Switches approaching 40 years of service life
- SCADA Radio/Cellular Communication (failure/obsolescence)

1.2.4. Transmission Line Conductor

The following components and operational/maintenance history may be considered to determine if transmission line conductors should be rebuilt or replaced:

- Conductor between 50-60 years of service life
- Multiple splices per phase per mile
- Conductor core/strands
- Connector
- Corrosion
- Heat damage
- Span length
- Metal type
- Shield wires (including OPGW)

1.2.5. Transmission Power Cable and Support Equipment

The following components and operational/maintenance history may be considered to determine if transmission power cable and support equipment should be rebuilt or replaced:

- Flexible power cable
  - Conduit
  - Impulse test
  - Insulation
  - Shielding
  - Terminators
  - Material availability
- High pressure oil insulated pipe type cable
  - Conduit
  - Impulse test
  - Insulation
  - Monitoring and protection system
  - Nitrogen gas system
  - Oil preservation system
  - Pressure system
  - Shielding
  - Terminators
  - Material availability

When additional reliability can be realized from system condition improvements, the system performance, operational flexibility, and communications methodologies should be considered to further improve the transmission grid.

2. System Performance Projects

Improving the health and increasing the reliability and flexibility of the FE transmission system is one of the core objectives of the methodology. Strategically reviewing the present system reliability and performance is important to achieving this objective. Planning analysis will include expanding the Bulk Electric System (BES) planning criteria to non-BES transmission system elements for purposes of identifying potential areas of concern in improving the overall system reliability and performance.

Identified projects are designed to enhance or improve overall reliability to customers and improve the operational flexibility for the transmission system control centers under maintenance and system restoration efforts.

When evaluating potential System Performance projects, consider these global factors, applicable to many types of system performance projects. These factors include:

- System reliability and performance
- Substation/line equipment limits
- Reliability of Non-Bulk Electric System (Non-BES) facilities
- Load at risk in planning and operational scenarios
- System losses
- Load and/or customers at risk on single source transmission lines
- Area load growth and load density
- Hardening system configuration

2.1. Equipment/Technology/Design Upgrades

As the transmission system developed over time, additions to the system were designed and built to the standards and state of the technology in place during construction. Retrofitting older equipment to present technology standards is not done automatically and there are types of legacy equipment and design that may present a reliability risk to the transmission system. Addressing legacy equipment and design within the methodology will provide reliability benefits to the transmission system. Which includes the following:

- BES ungrounded capacitor banks
- Ground switches replacement with Direct Transfer Trip
- On-off peak voltage band
- Power quality
- Circuit breaker configuration
- Circuit switcher limitations
- Line switch limitations
- FE-owned equipment located in non-FE affiliated facilities.

2.1.1. System characteristics:

- Clearance margins
- Future needs (e.g., fiber path)
- Galloping overlap
- Insulation coordination
- Lightning and grounding performance
- Structural capacity needs

2.2. System Conversion

Reviewing present transmission lines and substation system performance is an important step in improving system reliability and realizing the benefit of converting existing operating voltages.

Typically, a system is converted to a higher operating voltage to improve overall reliability and/or capacity of the system.

The following may be evaluated to determine if a system may be considered for conversion:

- Utilization factors
- Power flows on lines causing high system losses
- Stakeholder feedback
- Potential low voltage conditions
- Lines being operated with normally open points due to system flows or short circuit availability.
- Condition-based rebuilds

2.3. Network Radial Lines

Strategically reviewing the present system configurations of the transmission lines is an important step in improving system reliability.

The transmission system has existing radial lines, subject to more outages and of longer duration than those that are networked and fed from two different sources. Good engineering judgment should be applied to strategically determine the feasibility of looping lines.

Consider the following in determining the selection of radial transmission lines candidates for networking:

- Single sourced radial lines total load exposure
- Customer impact
- Radial lines defined by normally open points
- Proximity to other networked facilities
- Cost and constructability

2.4. Reconductor/Rebuild Transmission Lines

Strategically reviewing the system operations, performance, and condition of transmission lines is an important step in improving system reliability.

Consider past reliability, performance (including extended outages and/or extended outage durations), total customer or load interrupted, along with the following in determining the selection of transmission lines for reconductor/rebuild:

- Transmission line that cannot be utilized for operational switching
- Transmission lines that frequently require operational switching
- Transmission lines that are presently six-wired
- Transmission lines with concerns due to system fault characteristics
- Transmission lines with high loading
- Transmission lines with three or more terminals transmission lines
- De-energized/abandoned/un-utilized transmission lines
- High voltage underground or underwater cable
- Double circuit construction to a delivery point

2.5. Add/Replace Transformers

Strategically reviewing the present system performance and the addition or replacement of power transformers is important to improving reliability.

The following may be considered in determining whether a power transformer needs to be added or replaced on the system:

- System concerns related to loss of an existing transformer or other contingency scenarios at a specific voltage level(s)
- Transformers with normal loading approaching rating limits
- Transformers that frequently require operational switching

2.6. Add/Expand Bus Configuration

Strategically reviewing the current system configuration of the substations is an important step in improving system reliability.

The following may be considered in determining whether a substation could be selected for modification:

- Loss of substation bus adversely affects transmission system performance
- Eliminate simultaneous outages to multiple networked elements
- Accommodate future transmission facilities, constructability, and expansion
- Capability to provide operational flexibility to perform substation maintenance
- Substation elements that frequently require operational or transitional switching

2.7. Build New Transmission Line

An important step in improving system reliability is strategically reviewing the ability to utilize existing transmission line corridors and building transmission lines in new corridors to reinforce system configuration.

The following may be considered in determining whether a new transmission line should be constructed:

- Contingency constrained facilities
- Elevated loading on adjacent circuits
- Eliminated three or more terminal lines
- Opportunity to network radial facilities
- Reduction in the amount of FE load/customers served from external entities during contingency conditions
- Viability of an alternative resource such as large-scale storage
- Reduce customers/load loss during contingency conditions
- Improve reliability for non-BES facilities beyond N-1

2.8. Generation Switching Stations

Strategically reviewing present switchyard connection configurations for generation units (FE and Non-FE Generation) is an important step in improving system reliability.

The following may be considered in determining whether generation switching station configurations could be evaluated for reconfiguration:

- Evaluation of the primary protection for each power system element
- Prevention of the loss of a substation bus
- Elimination of simultaneous outages of multiple networked elements

2.9. Upgrade Relay Schemes

Strategically enhancing fault protection relay schemes will reduce the number of transmission system elements removed from service for a particular fault, reduce relay mis-operations, and increase the availability of transmission system elements.

Instead of replacing individual relays, relay schemes are generally replaced in their entirety with new FE standard relay designs. Benefits include reducing the complexity and increasing the speed of relay replacement projects, and providing for relay scheme standardization across the entire FE footprint. These provide additional reliability improvements to the transmission system, including test switches and installing newer auxiliary relays.

The following may be considered in determining whether relay schemes are candidates for replacement:

- Legacy capacitator bank schemes
- Communications technology
- Ancillary benefits (i.e., broken conductor detection, health monitoring, automated fault location or increased oscillography)
- Bus protection schemes
- Bus protection schemes which rely on remote clearing
- Protection system with single points of failure
- Relay schemes that have a history of mis-operation
- Obsolete and difficult to repair communication equipment (i.e., Pilot wire, Power line Carrier, etc.)
- Obsolete firmware or software
- Inadequate remote backup for circuit breaker failure to trip
- Relays with their Potential source located on a different line exit/ring bus position

2.10. Automatic Sectionalizing Schemes

Increasing the reliability of the FE transmission system is one of the objectives of the methodology, including changing network switches at some substations so their switches are automated to open or close during system events.

- Projects are developed under the methodology by evaluating load at risk and/or customers impacted.

2.11. Add SCADA Control

Strategically reviewing the current system application of SCADA control is an important step in improving system reliability and performance.

The following may be considered in determining whether the addition of SCADA control could be considered:

- Transmission capacitor banks
- Line exposure and potential outage duration
- Remote switch location
- Transmission through flow
- Relay control required for switching operations

2.12. Improve Fault Recorder Communications

Selectively improving the communications channels used to query existing fault recording equipment will improve fault location capability and improve event analysis.

Downloading information from existing fault recording equipment at some substations can cause a disruption of communication used by the backup Emergency Management System (EMS). The cause of this problem has been identified as insufficient bandwidth on the network connection to these locations.

Existing mitigation of this problem is to manually and infrequently poll these devices.

Before manually downloading fault recorder data, permission must be obtained from FE Transmission System Operators (TSO). This request for permission will cause delay in obtaining data.

The following may be considered in determining whether to undertake a project to improve fault recorder communications:

- Communication channels where bandwidth is limited
- Fault recorder condition

3. Operational Flexibility Projects

Increasing the system capacity (i.e., loading margin) of the FE transmission system is one of the core objectives of the methodology. Strategically reviewing the present system configuration and its capabilities is important to achieving this objective. Planning analysis will include expanding the BES planning criteria to non-BES transmission system elements to identify potential areas of concern for improving the overall system reliability and performance.

Identified projects are designed to enhance or improve overall reliability to customers. They also improve the operational flexibility of the transmission system control centers under maintenance and system restoration efforts.

3.1. Permanent Reactive Device Installations

Strategically reviewing reactive devices' availability and utilization is an important step in improving operational flexibility.

The following may be considered in determining whether to install a reactive device:

- Mobile reactive devices required for continued operational voltage support
- Non-BES transmission systems facilities evaluation identifies the need for a permanent reactive device
- Reactive devices with multiple trips in recent years
- Transients during capacitor switching
- Reactive devices to reduce high voltage
- Reactive devices to reduce transients and/or out rush currents during switching and fault conditions
- System losses

3.2. Circuit Breakers and Other Fault Interrupting Devices

Replacing breakers that limit the operation of the transmission system allows extra flexibility in system operations. The following may be considered in determining whether to replace breakers:

- Breakers/devices where operation is blocked for certain fault conditions
- Breakers/devices that cannot interrupt available fault current
- Breakers/devices that have a reduced ability to auto-reclose due to available fault current
- Breakers/devices with high fault duties along with its condition assessment
- Breakers/devices with a single trip coil
- Replace breakers/devices on tapped transformers that are not fully rated to clear faults on the transformer and require clearing the remote line ends to clear the transformer fault.

3.3. Transmission EMS Power Network Analysis (PNA) Enhancements

The State Estimator (SE) solution quality used for contingency analysis can be improved by strategically installing metering at select locations. This allows improved analysis for real-time switching capabilities and scheduling next day outages, long-term outages, and system restoration.

Consider the following when determining whether to install metering for Transmission EMS PNA Enhancements:

- Transmission lines with multiple tapped load connections
- Transmission lines with multiple tapped load connections and a normally open tie point
- Distribution transformers that have the potential of back-feeding into the transmission system
- Distribution transformers where metering would enhance Operator situational awareness or Transmission EMS PNA solution quality

3.4. System Upgrades

Strategically reviewing Relay functionality against changing Generation mix, System loading, and System conditions, including maintenance and system restoration efforts, is an important step in maintaining and improving operational flexibility including consideration of the benefits of conversion to a digital substation.

The following may be considered when determining whether System modifications may be required to maintain operational flexibility in light of changing System conditions:

- Capability to perform line/substation maintenance due to system flows or short circuit availability
- Transmission lines that frequently require operational switching, resulting in significant load at risk and/or customers affected
- Load areas with only two sources that loss of one element results in a radial load pocket greater than 100 MW

4. Communications: Reliability, Capability, and Resilience Projects

A number of key investments in the reliability of the transmission system are driving the scoping and prioritization of sites for communications system reliability, compliance, and security projects.

4.1. Transmission Substation Communication Network

The core of the methodology Network and Security (N & S) scope centers on the design and implementation of a transmission substation network that will provide secure and resilient communications for data, voice, and SCADA/EMS traffic.

The Transmission Substation Network leverages a combination of transport technologies – including fiber, digital microwave, licensed 700 MHz, unlicensed 900 MHz, leased MPLS, and cellular.

The following components are evaluated for the development of the transmission substation network:

4.1.1. High Capacity Backhaul

Fiber and digital microwave provide the backhaul across a redundant and diverse network, using Multi-Protocol Label Switching (MPLS) as the key underlying transport technology. The following should be considered when evaluating the high capacity backhaul:

- Bandwidth and latency requirements of substation data
- Diverse and redundant paths to Control Centers and Data Centers
- Generators and DC backup power systems
- Single points of failure on the backhaul network.

Installation of fiber, [OPGW, All-Dielectric Self-Supporting (ADSS)], or underground, should be considered for all designed transmission line projects, except where there is clearly no future use for high-bandwidth communications to the site and the site does not provide a diverse path for other transmission sites. Due to its inherently higher reliability, resilience to storms, and independence from outage scheduling, underground fiber is preferred over aerial construction wherever it is not cost prohibitive or requires excessive delays in project execution.

4.1.2. High Bandwidth Substations

Individual sites may also warrant high bandwidth connections from the backbone to outlying substations. These high bandwidth requirements are driven by substation classification and include Tier 1, Tier 2, and selected Tier 3 sites.

4.1.3. Low Bandwidth Substations

Individual sites that are classified as low bandwidth or remote locations may be connected by a wireless solution to provide the communications from the backbone to remote transmission substations and line devices.

4.1.4. Remote Terminal Unit (RTU)

RTUs at selected transmission substations should be upgraded to the latest FE equipment and protocol standards, therefore improving SCADA/EMS reliability. Key considerations for prioritization of RTU upgrades include:

- Equipment and SCADA protocol obsolescence
- Equipment end-of-life and end of vendor support
- Historical reliability

4.1.5. Fiber Replacement

A large portion of the existing fiber network and optical transport systems on which the Transmission Substation Network is built is approaching end-of-life. These assets provide the transport for critical communications that are used for the monitoring, control, protection, security, and asset health of transmission substations. Key considerations for prioritization of fiber replacements include:

- Age of installed fiber
- Dark fiber availability
- Failure frequency on fiber route
- Fiber cable obsolescence

Optical Ground Wire (OPGW) fiber replacement projects must be closely coordinated with transmission line rebuild and/or reconductor projects that are planned for the same route. This ensures that costs are optimized, structural impacts are minimized, and outages are well-planned to meet existing and future electrical and communications requirements.

4.2. Transmission Protection Scheme Communications

Legacy equipment that currently provides transmission line primary protection communications should be evaluated for replacement, migration to the SONET tele-protection system, or migration to protection communications over direct fiber. Key considerations for prioritization of primary protection communications upgrades include:

- Historical reliability
- Communications technology obsolescence
- Equipment end-of-life and end of vendor support

4.3. Transmission EMS and Distribution ADMS/OMS Decoupling

A strategy has been implemented to decouple the Energy Management System (EMS), Advanced Distribution Management System (ADMS), and Outage Management System (OMS) from each other. Separate operational systems (EMS vs ADMS/OMS) allow transmission operators to manage the transmission system without the complexity and operational impact introduced by distribution-related applications. A purpose-built transmission EMS also supports EMS changes independent of distribution applications to address specific operational needs of the transmission organization, such as new NERC Requirements.

5. Security Projects

SECTION NOTE

Due to the security sensitivity of this information, the specific criteria used in the transmission substation classification, along with the security protections at those sites, are not published.

5.1. Transmission Substation Physical Security Upgrades

A key component of the methodology Network & Security investments includes enhanced physical security protections for assets that are critical to BES reliability. The physical security protections at each site are determined by an evaluation utilizing a substation classification.

5.1.1. Substation Classification

- Transmission Planning & Protection determines the substation tier level based upon criticality to the BES
- Security risk assessments (threat and vulnerability)
- Consideration of local factors

5.1.2. Physical security upgrade selections are guided by their ability to deter, detect, assess, delay, and respond to events. Principles of Crime Prevention Through Environmental Design (CPTED) are implemented to identify emergent threats and develop mitigation strategies.

5.2. Transmission Substation Cyber Security Upgrades

The Transmission Substation Network is designed around a segmented architecture that isolates less critical substations with fewer physical protections from more critical substations, thereby reducing overall risk to the BES. Enhancing the security framework at critical substations also provides a mechanism to meet new reliability requirements under the NERC CIP Standards. MPLS extends security services to edge devices in the transmission substations (e.g., access control, encryption, intrusion prevention). New and emerging cyber vulnerabilities will continue to be assessed and mitigated to further harden the EMS/SCADA environment.

5.3. Transmission Security Operations Center (TSOC)

A TSOC was implemented to monitor and protect transmission system assets. This 24x7 staffed facility integrates and correlates multiple alarms and events from Cyber Security, Physical Security, Information Technology (IT), and Operational Technology (OT). Specific alerts and information are shared with national entities (e.g., Department of Energy, Department of Homeland Security, and Electricity Sector Information Sharing and Analysis Center). Emerging tools and technologies will be evaluated and implemented to enable faster response to Indicators of Compromise and proactive threat hunting to protect critical systems.

6. Transmission Asset Health and Inventory Programs

The objective of this program is to collect data and perform analytics to provide an assessment of asset health, predict failures, and determine actions required for proactive asset management.

6.1. Asset Health Systems

The Asset Performance Management System (APM) desires to bring together the full range of disparate asset information, asset management algorithms based on subject-matter expertise, and intelligent software solutions, all on a single platform that can cover all asset types.

Data can come from any source, online or offline, real time or batch. It leverages its existing infrastructure and designs to deliver digital equipment history records, online monitoring, and operational data acquisition data to the asset. There, asset condition monitoring and performance algorithms (e.g., asset performance and risk of failure) can be applied and a full spectrum of business intelligence tools and techniques (e.g., drill-down capabilities, key performance indicators, and real-time information dashboards) will be used on data sets to provide visibility for driving decision processes, both strategic and operational.

6.2. Remote Monitoring of Assets

Remote and real-time monitoring of assets will be considered for deployment and implementation via local assets monitoring devices, the transmission network communication system (being enhanced/expanded for the transmission system), and the new AHMS. Transformer and Breakers on-line monitoring are being implemented. Monitoring data are being collected and analyzed by APM system.

Remote assets monitoring may include:

- Substation Protection and Control Intelligent Electronic Devices (IED)
- DC system status/condition monitoring
- CCVTs and PTs
- Power transformer on-line status/condition monitoring
- EHV circuit breakers status/condition monitoring
- Synchronous condensers
- Static VAR compensators
- Station service
- Emergency generators
- Protective relaying/DFR status
- Substation physical security alarms
- Weather sensor/stations

6.3. Asset Inventory Program and Data Governance

The objective of this program is to ensure substation asset data and characteristics are robust and sufficient to meet all NERC requirements.

Acronyms

Acronym	Definition
ADMS	Advanced Distribution Management System
ADSS	All-Dielectric Self-Supporting
APM	Asset Performance Management System
BES	Bulk Electric System
CCVT	Coupling capacitor voltage transformers
CPTED	Crime Prevention Through Environmental Design
CT	Current Transformers
DFR	Digital fault recorder
EMS	Emergency Management System
FE	FirstEnergy
GIS	Gas Insulated Substation
IED	Intelligent Electronic Devices
IT	Information Technology
LTC	Load Tap Changers
MCOV	Maximum Continuous Operating Voltage
N&S	Network and Security
Non-BES	Non-Bulk Electric System
OMS	Outage Management System
OPGW	Optical Ground Wire
OT	Operational Technology
PNA	Power Network Analysis
PT	Potential transformers
RTEP	Regional Transmission Expansion Planning
RTU	Remote Terminal Unit
SE	State Estimator
SPE	System Performance Excellence
SVC	Static VAR Compensator
TSO	Transmission System Operators
TSOC	Transmission Security Operations Center

Related Documents

Title
N/A

Revision History

Rev	Effective Date	Preparer	Comments
3	04/28/2025	R. Shultz	SMEs System Condition Projects D. Kibler C. Richards R. Grady R. Preslan System Performance Projects S. Sun D. Barber R. Solic Operational Flexibility Projects M. McGuire Communications: Reliability, Capability, and Resilience Projects G. McDonald Security Projects K. Schick A. Rossetti Transmission Asset Health and Inventory Programs K. Fickey B. Dinh Updated format of all multilevel lists to comply with template. To be in compliance with template, changed first section title from “FE Utilities Transmission SPE Program Overview” to “Purpose”. Conformed doc to template by adding Applicability section. Language for section was created by repurposing second paragraph of Purpose statement. **1.1 Substation Condition Rebuild/Replacement** Updated per user comments (space constraints…obsolescence) **1.1.1** Updated circuit break/fault interrupting devices list to user comments **1.1.2. Power Transformers and Load Tap Changers (LTCs)** updated operation, analysis, and containment pump descriptions assessment criteria. **1.1.3. Station Service Transformers and Emergency Generators** updated panel box and scheme descriptions. **1.1.4 Throw-over Schemes Capacitor Bank Installations** updated fault history, Structural integrity, Bus work condition assessment criteria. **1.1.5 Reactive Power Support Systems** added controller and comms assessment criteria and qualified Thyristor criteria. **1.1.6 Switches** added load break system criteria. **1.1.7 Station DC Systems** removed system monitoring, updated and added battery review criteria. **1.1.8 Station System Protection and Controls** removed most electromechanical relay review criteria details.

Rev	Effective Date	Preparer	Comments
			1.1.10 Current Transformers (CTs), Control Cables, and Cable Trays added cable tray and trench and power factor review criteria. **1.1.12 Ground Grid** added ground grid review criteria **1.1.13 Perimeter Fencing, Station lighting, and Other Security Technology** added physical security and station lighting review criteria. **1.1.14 Steel Structural Components and Their Associated Foundations** added ground setting review criteria. **1.1.15 Line Arresters** removed porcelain and SiC review arrester criteria. **1.1.16 Risers and Connections** added ground setting review criteria. **1.1.17 Conduits and junction Boxes** added ground setting review criteria and removed station lighting criteria. **1.1.18 Facilities** added ground added facility space, lighting, access, HVAC, access roads and rail review criteria. **1.1.19 Meters, Transducers, and Other Measuring Devices** updated accuracy and software compatibility review criteria. **1.1.20 Intelligent Electronic Devices (IEDs)** updated software compatibility review criteria. **1.1.22 Capital Tools** added this section. **1.2 Line Condition Rebuild/Replacement** significant updates to wood pole, conductor and hardware, system characteristics, environmental factors, and outage frequency/duration review criteria. **1.2.2 Transmission Line Hardware** updated armor and spice review criteria. **1.2.3 Transmission Line Switches** updated switch configurations. **1.2.5 Transmission Power Cable and Support Equipment** updated cable review criteria. **2 System Performance Projects** updated description and added and removed evaluation factors. **2.2 System Conversion** significantly updated description. updated **2.4 Reconductor/Rebuild Transmission Lines** updated customer selection criteria, and updated high voltage criteria description. **2.6 Add/Expand Bus Configuration** removed customer impact criteria and updated capability selection criteria. **2.7 Build New Transmission Line** minor updates to descriptions. **2.9 Upgrade Relay Schemes**

Rev	Effective Date	Preparer	Comments
			minor updates to criteria descriptions. **2.11 Add SCADA Control** minor updates to criteria descriptions. **3.2 Circuit Breakers and other Fault Interrupting Devices** minor updates to criteria descriptions, added breaker replacement review criteria. **3.4 System Upgrades** updated system upgrade selection criteria description and added load area criteria description. **5.1 Security Projects** minor updates to selection criteria. **6.1 Asset health** minor updated to description. **6.2 Remote monitoring of assets** added transformer and breaker monitoring language.
2	11/09/2023	L. Koshar	Updated language throughout document. Added paragraphs 3.4, 3.5 and 4.3. Additional paragraphs inserted into Section 4. Updated format.
1	12/04/2020	M. Barnes	Updated format to new standard and additional detail added to the System Conditions Projects section for clarity.
0	11/2018	David Tates	Initial Procedure Creation.

Approvals

This document was reviewed and approved electronically. Records are available upon request through the Transmission Operations Support Compliance & Procedures group.

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