FirstEnergy Utilities - Transmission

Energizing the Future (EtF) Project/Program Methodology

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FirstEnergy Utilities Transmission EtF Program Overview

The FirstEnergy Utilities' "Energizing the Future" (EtF) program is the current program for identifying and making the needed investments in FirstEnergy transmission systems. EtF will improve the health, reliability, and capacity of the FirstEnergy transmission system for existing and new customer loads. It is designed to fulfill the obligations of the FirstEnergy companies under the PJM Regional Transmission Expansion Planning (RTEP) process, upgrade the condition of equipment, enhance system performance, improve operational flexibility, improve the Information Technology (IT) network infrastructure, upgrade system cyber and physical security, and evaluate the health and inventory of the transmission system.

The methodology and guidelines contained within this document serve to identify potential projects and programs to achieve the overall desired results of improving the health, reliability, and capacity of the FirstEnergy transmission system for existing and new customer loads. Projects are identified based on guidelines provided in one or multiple of the project areas described below.

Overview of the 6 types of projects

This document outlines guidelines for 6 different types of projects:

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 & Inventory Programs

Each project type plays a critical role in achieving the desired results of the EtF program. These project categories were determined based on the unique benefit they provide to the FirstEnergy transmission system.

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 FirstEnergy transmission facilities is one of the core objectives of the EtF program. 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 the FirstEnergy transmission facilities can be improved by rebuilding and/or replacing substation equipment where appropriate. In order 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
- Customer outage frequency and/or durations
- 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, 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

The review may also consider the following operational information, maintenance history, and ancillary equipment performance associated with the asset types listed in the Index 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 load tap changers (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 and other support equipment (GIS)

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:

A. Compressor
B. Condition of interrupting media (oil, gas, etc.)
C. Contact resistance
D. Contact timing
E. Insulation power factor
F. On-line timing
G. Operating mechanism
H. Synchronous close control units
I. Tank heater
J. Time travel analysis
K. Trip and close coils

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:

A. Alarm and device testing (includes thermometers, pressure devices, and nitrogen system)
B. Bushings
C. Core ground
D. Dissolved gas in oil
E. Insulation power factor (Doble^{TM})
F. Internal inspection of the clamping, blocking, steel core, and core and coil support structure shall be performed
G. Load tap changer
H. Loading and fault history
I. Moisture content
J. Oil dielectric
K. Oil screen
L. Oxygen content
M. Pumps/fans
N. Radiators
O. Surge arresters
P. Total combustible gas
Q. Turns ratio

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:

A. Capacity
B. Engine generator and controls:
   B.1 Battery
   B.2 Cathodic protection testing
   B.3 Engine coolant/heating systems
   B.4 Transfer switch/control
C. Panel boxes and associated conduits
D. Physical condition
E. Throw-over schemes

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:

A. Capacitor can
B. Capacitor configuration
C. Capacitor switching device (breaker or cap switcher)
D. Control system
E. Current transformers (CT)
F. Neutral and series capacitance checks
G. Panel boxes and wiring
H. Potential transformers (PT)
I. Reactors
J. Unbalanced voltage conditions

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:

A. Static VAR Compensator (SVC):
   A.1 Building condition
   A.2 Capacitors
   A.3 Control systems
   A.4 Reactors
   A.4 Thyristor switching circuit
   A.6 Thyristor cooling system
B. Synchronous condenser:
   B.1 Bearings and lubricating systems
   B.2 Building condition
   B.3 Control systems
   B.4 Field circuit breaker
   B.5 Hydrogen cooling system
   B.6 Rotor
   B.7 Stator

1.1.6 Switches

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

A. Gang-operated or motor operated switches:
   A.1 Blade and jaw assembly
   A.2 Control system
   A.3 Mounting assembly
   A.4 Operating mechanism
   A.5 Switching capabilities (load, charging current, and parallel isolation)

- A.6 Switch degradation

B. Stick-operated line and/or bus switch:
- B.1 Blade and jaw assembly
- B.2 Mounting assembly
- B.3 Switching capabilities (load, charging current, and parallel isolation)
- B.4 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:

A. Batteries:
- A.1 Capacity
- A.2 Discharge test data
- A.3 Electrolyte (specific gravity and excessive hydration)
- A.4 Excess sediment
- A.5 Impedance test data
- A.6 Intercell connection
- A.7 Jar/cell (container, cover, flame arrester, and seals)
- A.8 Monitoring system
- A.9 Plate
- A.10 Rack condition
- A.11 Terminal Post

B. Chargers:
- B.1 AC ripple voltage and current
- B.2 Capacity
- B.3 Condition (damage, overheating, and excessive deterioration)
- B.4 Control system

C. 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:

A. Electromechanical relays:
- A.1 Capability
- A.2 Case
- A.3 Component condition (coils, contacts, resistors, capacitors, and thyristors)
- A.4 Isolation

C. Microprocessor relays:
    - C.1 Capability
    - C.2 Case
    - C.3 Control board
    - C.4 Input/output module
    - C.5 Isolation
    - C.6 Software compatibility and/or obsolescence
    - C.7 Test data

B. Solid state relays:
    - B.1 Capability
    - B.2 Case
    - B.3 Input/output module
    - B.4 Isolation

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:

A. 138 kV breakers with bushing potential devices
B. Capability (accuracy, measurements, and data retention)
C. Capacity
D. Coupling capacitor voltage transformers (CCVTs)
E. Potential transformers (PTs)
F. Readability
G. Transducers
H. Also see section K – 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:

A. Cable capability (size and thermal rating)
B. Cable insulation
C. Cable tray loading
D. Contingency exposure
E. CT accuracy
F. CT burden
G. CT insulation
H. CT ratio

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 or replaced:

A. Carrier set communication signals
B. Carrier set spark gap
C. Carrier tuning units
D. Carrier tuning unit spark gap
E. CCVT
F. CCVT spark gap
G. Coax cable
H. Electrical/communication performance
I. Wave trap and filter

1.1.12 Ground grid

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

A. Ground grid network
B. Ground rods
C. Point copper contact grounding devices
D. Swage, cadweld, brazed, and bolted connections

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:

A. Cyber security issues and concerns
B. Perimeter Fencing
   - B.1 Broken or missing barbed wire
   - B.2 Fence height
   - B.3 Gaps in fabric
   - B.4 Gate misalignment
   - B.5 Holes in fabric
   - B.6 Non-cut proof fabric
   - B.7 Personnel safety with manual gate
   - B.8 Rusted or damaged posts
C. Physical security issues and concerns
   - C.1 Access control
   - C.2 Audio response
   - C.3 High definition CCTV
   - C.4 Object oriented analytics technology
   - C.5 Thermal imaging
D. Station lighting (mercury & incandescent)
   - D.1 Illumination level

D.2 Obsolete technology (mercury & incandescent)

1.1.14 Steel structural components and their associated foundations

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

A. Concrete foundations
   - A.1 Crumbling concrete
   - A.2 Exposed or compromised rebar
B. Grillage style foundations
   - B.1 Crumbling concrete
   - B.2 Exposed or compromised plate
   - B.3 Exposed or compromised steel beam
C. Rusted or damaged steel

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:

A. Damaged insulation layer
B. Insulation meg-ohm
C. Insulation power factor
D. MCOV rating
E. Porcelain style arresters
F. Silicone Carbide (SiC) arresters

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:

A. Conductor core/strands
B. Connector
C. Corrosion
D. Heat damage on riser or connector
E. Length
F. Metal type

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:

A. Control, power, potential transformer cables
B. Current transformer cables
C. Holes in conduit
D. Holes in junction boxes
E. Separation of conduit from junction boxes
F. Station lighting
G. Temporary junction box installation
H. Tripping hazards related to conduit

1.1.18 Facilities

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

A. Access control
B. Comingled/Third party equipment
C. Constructability and maintenance
D. Overall condition (foundation, walls, and roof)
E. Physical security
F. Safety and human performance

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:

A. Capabilities
B. Communication upgrades
C. Consolidation of components
D. Deteriorated transducers
E. Digital fault recorder (DFR)
F. RTU upgrades
G. Software compatibility and/or obsolescence

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:

A. Controls
B. Microprocessor devices
C. Monitors
D. Software compatibility and/or obsolescence

1.1.21 Gas Insulated Substation and other support equipment (GIS)

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:

A. Breakers
B. Bushings
C. Disconnect/grounding switches
D. Gas leakage
E. Gas quality
F. Monitoring system
G. Obsolete technology
H. Partial discharge
I. PTs and CTs
J. Support steel

1.2 Line Condition Rebuild/Replacement

The health of the FirstEnergy transmission facilities can be improved by rebuilding and/or replacing transmission lines where appropriate. FirstEnergy will review and assess existing transmission facilities for equipment characteristics that are near or beyond their existing service life or contain components that are obsolete. In order to determine whether lines should be rebuilt or replaced based on their condition, the following global characteristics may be considered:

- Level of criticality to system performance and operations
- Negative impact on equipment health and/or system reliability
- Customer outage frequency and/or durations
- 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, or application design error
- Limited availability of spare parts and/or vendor technical support
- Operation, design, or installation limitations
- Age/condition of wood pole transmission line structures
- Age/condition of steel tower or steel pole transmission line structures
- Age/condition of transmission line conductors and compression fittings
- System characteristics including lightning and grounding performance, galloping overlap, insulation coordination, structural capacity needs, clearance margins, and future needs (e.g. fiber path)
- Current design criteria, applicable codes, and industry best practices

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 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 & 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 & 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:

A. Cost to access the structure
B. Foundations
C. Steel members
D. Steel structural components and their associated foundations:
   D.1 Grillage style foundations
E. Steel structure fasteners
F. Wafering of Corten steel members
G. Wood cross arm and brace
H. Wood pole reinforcements:
   G.1 Steel C-Truss
   G.2 Wood cross arms
   G.3 Wood stub pole
I. Wood poles with phase raisers
J. Wood poles with pole tops

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:

A. Cross arms and hardware
B. NESC required loads for replacement insulator applications
C. Polymer insulators
D. Porcelain insulators
E. Shunt splices

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:

A. Accessibility
B. Manually-operated switches
C. Motor-operated switches
D. Switch configuration (e.g. HV whips, vacuum bottles)
E. Type KPF switches

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:

A. Conductor core/strands
B. Connector
C. Corrosion
D. Heat damage
E. Length
F. Metal type
G. Shield wires

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:

A. Flexible power cable
   - A.1 Conduit
   - A.2 Impulse test
   - A.3 Insulation
   - A.4 Shielding
   - A.5 Terminators
B. High pressure oil insulated pipe type cable
   - B.1 Conduit
   - B.2 Impulse test
   - B.3 Insulation
   - B.4 Monitoring and protection system
   - B.5 Nitrogen gas system
   - B.6 Oil preservation system
   - B.7 Pressure system
   - B.8 Shielding
   - B.9 Terminators

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 of the FirstEnergy transmission system is one of the core objectives of the EtF program. 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 to identify potential areas of concern to be considered for improving the overall system reliability and performance.

Projects that are identified are designed to enhance or improve the 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, the evaluator will take into account a number of global factors that may apply to many types of projects. These global 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 transmission lines

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. Although retrofitting older equipment to the present technology standard is not something which is done automatically, there are several specific types of legacy equipment and design that may be considered to present a particular risk to the reliability of the transmission system. Addressing these within the EtF program will provide reliability benefits to the transmission system.

2.1.1 BES ungrounded capacitor banks
2.1.2 Ground switches
2.1.3 On-off peak voltage band
2.1.4 Power quality
2.1.5 Circuit breaker configuration
2.1.6 Line switch limitations
2.1.7 FirstEnergy-owned equipment located in non-FirstEnergy affiliated facilities
2.1.8 System characteristics:
- A. Clearance margins
- B. Future needs (e.g. fiber path)
- C. Galloping overlap
- D. Insulation coordination
- E. Lightning and grounding performance
- F. Structural capacity needs

2.2 System Conversion Methodology

Strategically reviewing the present system performance of transmission lines and substations and the benefit of converting existing operating voltages is an important step in improving system reliability.

A system is typically converted to a higher operating voltage to improve the overall reliability and/or capacity of the system. The following may be considered to determine if a system may be considered for conversion:

2.2.1 Utilization factors
2.2.2 Flows on lines causing high system losses
2.2.3 Customer feedback
2.2.4 Potential low voltage conditions
2.2.5 Lines being operated with normally open points due to system flows or short circuit availability
2.2.6 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 that are 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.

The following may be considered in determining the selection of the radial transmission lines that may be considered for networking:

2.3.1 Load at risk and/or customers affected
2.3.2 Proximity to other networked facilities
2.3.3 Radial lines defined by normally open points

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. Past reliability performance, including extended outages and/or extended outage durations and the following may be considered in determining the selection of the transmission lines that may be considered for reconductor/rebuild:

2.4.1 Transmission line that cannot be utilized for operational switching
2.4.2 Transmission lines that frequently require operational switching
2.4.3 Transmission lines that are presently six-wired
2.4.4 Transmission lines with concerns due to system fault characteristics
2.4.5 Transmission lines with high loading
2.4.6 Three or more terminal transmission lines
2.4.7 De-energized/abandoned transmission lines
2.4.8 High Voltage underground cable

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:

2.5.1 System concerns related to loss of an existing transformer or other contingency scenarios at a specific voltage level(s)
2.5.2 Transformers with normal loading approaching rating limits
2.5.3 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:

2.6.1 Loss of substation bus adversely affects transmission system performance
2.6.2 Eliminate simultaneous outages to multiple networked elements
2.6.3 Accommodate future transmission facilities
2.6.4 Capability to perform substation maintenance

2.7 Build New Transmission Line

Strategically reviewing the ability to utilize existing transmission line corridors as well as building transmission lines in new corridors to reinforce the system configuration is an important step in improving system reliability.

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

2.7.1 Contingency constrained facilities
2.7.2 Loading on adjacent circuits
2.7.3 Three or more terminal lines
2.7.4 Network radial lines
2.7.5 Reduction in the amount of FE load/customers served from external entities during contingency conditions

2.8 Generation Switching Stations

Strategically reviewing present connection configurations of switchyards for generation units (FirstEnergy and Non-FirstEnergy 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:

2.8.1 Evaluation of the primary protection for each power system element
2.8.2 Prevention of the loss of a substation bus
2.8.3 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 misoperations, and increase the availability of transmission system elements.

In general, relay schemes will be replaced in their entirety with new FirstEnergy standard relay designs in lieu of replacing individual relays. This will have numerous benefits, including reducing the complexity and increasing the speed of relay replacement projects, providing for relay scheme standardization across the entire FirstEnergy footprint, as well as providing additional reliability improvements to the transmission system (such as including test switches and installing newer auxiliary relays).

The following may be considered in determining whether relay schemes could be selected as candidates for replacement:

- **2.9.1** Legacy capacitor bank schemes
- **2.9.2** Communications technology upgrades
- **2.9.3** Ancillary benefits (i.e. automated fault location or increased oscillography)
- **2.9.4** Bus protection schemes
- **2.9.5** Bus protection schemes which rely on remote clearing
- **2.9.6** Protection system with single points of failure
- **2.9.7** Relay schemes that have a history of misoperation
- **2.9.8** Obsolete and difficult to repair communication equipment (DTT, Blocking, etc.)
- **2.9.9** Obsolete firmware or software

2.10 Automatic Sectionalizing Schemes

Increasing the reliability of the FirstEnergy transmission system is one of the objectives of the EtF program. The network switches at some substations may have their switches automated to open or close during system events.

- **2.10.1** Projects are developed under this 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:

2.11.1 Transmission Capacitor banks
2.11.2 Potential outage duration
2.11.3 Remote switch location
2.11.4 Transmission through flow

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. The cause of this problem has been identified to be insufficient bandwidth on the network connection to these locations.

The existing mitigation for this problem has been to infrequently poll these devices manually.

Permission must be obtained from FirstEnergy Transmission System Operators before manually downloading fault recorder data. This results in a longer delay in getting usable information from these devices.

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

2.12.1 Communications channels where bandwidth is limited
2.12.2 Fault recorder condition

3 OPERATIONAL FLEXIBILITY PROJECTS

Increasing the system capacity (i.e. loading margin) of the FirstEnergy transmission system is one of the core objectives of the EtF program. Strategically reviewing the present system configuration and its capabilities are 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 to be considered for improving the overall system reliability and performance.

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

3.1 Permanent Reactive Device Installations

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

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

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

3.2 Replace Breakers

Replacing breakers that limit the operation of the transmission system will allow for more flexibility in system operations. The following may be considered in determining whether to replace breakers:

- **3.2.1** Breakers where operation is blocked for certain fault conditions
- **3.2.2** Breakers that cannot interrupt available fault current
- **3.2.3** Breakers that have a reduced ability to auto-reclose due to available fault current
- **3.2.4** Breakers with high fault duties along with its condition assessment.
- **3.2.5** Breakers with a single trip coil

3.3 Operational Metering

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

The following may be considered in determining whether to install operational metering:

- **3.3.1** Transmission lines with multiple tapped load connections
- **3.3.2** Transmission lines with multiple tapped load connections and a normally open tie point
- **3.3.3** Distribution transformers that have the potential of back-feeding into the transmission system

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 EtF 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:

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

4.1.2 High Bandwidth Substations

Individual sites may also warrant high bandwidth "spurs" from the backbone to outlying substations. These high bandwidth requirements are driven by the substation classification methodology 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, improving SCADA/EMS reliability. Key considerations for prioritization of RTU upgrades include:

A. Equipment and SCADA protocol obsolescence
B. Equipment end-of-life and end of vendor support
C. 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 are approaching end-of-life. These assets provide the "bulk 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:

A. Age of installed fiber
B. Dark fiber availability
C. Failure frequency on fiber route
D. Fiber cable obsolescence

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:

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

4.3 Transmission EMS and Distribution ADMS/OMS Decoupling

A strategy is being developed surrounding the future platforms for the Energy Management System (EMS), Advanced Distribution Management System (ADMS), and Outage Management System (OMS). Separate operational systems (EMS vs ADMS/OMS) will allow transmission operations to be completed without the complexity and operational impact introduced by distribution. As part of this strategy, transmission & distribution RTUs will be assessed for potential decoupling as well. A purpose-built transmission EMS will allow adaptations for transmission's specific operational needs to be addressed more efficiently, including future NERC Requirements.

5 SECURITY PROJECTS

5.1 Transmission Substation Physical Security Upgrades

A key component of the EtF Network & Security investments includes enhanced physical security protections for assets that are critical to the reliability of the Bulk Electric System (BES). The physical security protections at each site are primarily based on an evaluation utilizing a substation classification methodology.

5.1.1 Substation Classification Methodology

A. Consideration of local factors
B. Prioritized "tiers" based on criticality to the Bulk Electric System
C. Site security vulnerability assessments

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

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 Bulk Electric System. 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 the transmission system assets. This 24x7 manned facility integrates and correlates multiple alarms & 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 actions required for proactive asset management.

6.1 Asset Health Systems

The Asset Health Monitoring System (AHMS) implementation 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 is able to cover all asset types. Data can come from any source, online or off-line, real time or batch. It is leveraging its existing infrastructure and designs to deliver digital equipment history records, on-line monitoring and operational data acquisition data to the asset health center. There, asset condition monitoring and performance algorithms (for example, asset performance and risk of failure) can be applied and a full spectrum of business intelligence tools and techniques (for example, drill-down capabilities, key performance indicators, and real-time information dashboards) will be put to use 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 that is being enhanced/expanded for the transmission system, and the new Asset Health Monitoring System (AHMS).

Remote monitoring of assets may include:

- **6.2.1** Substation Protection and Control Intelligent Electronic Devices (IED)
- **6.2.2** DC system status/condition monitoring
- **6.2.3** CCVTs and PTs
- **6.2.4** Power transformer on-line status/condition monitoring
- **6.2.5** EHV circuit breakers status/condition monitoring
- **6.2.6** Synchronous condensers
- **6.2.7** Static VAR compensators
- **6.2.8** Station service
- **6.2.9** Emergency generators
- **6.2.10** Protective relaying/DFR status
- **6.2.11** Substation physical security alarms
- **6.2.12** 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.

7 REVISION PROCESS

All major and minor revisions of this document are reviewed and approved by the applicable Directors and the Director, Transmission Planning & Protection. The revision process is as follows:

1. The revisions/clarification are determined as major or minor by the Director, Transmission Planning & Protection.
2. The document changes are maintained by a redline version.
3. The date, type, and description of the revision are recorded in the Revision History Table.

Revision History

Rev.	Date Revision Started	Revision Effective Date	Name	Review / Revision Comments