Network Model and SCADA Maintenance Process

Version 5

February 2025

Revision History

Version	Date	Reviewer	Revisions
1	2/23/17	Heidi Mansion Tony Hudson	Initial Document
2	5/1/2024	Hans Tang Falon Dostal	Process updates
3	5/30/2024	Hans Tang Vincent Roberts	Review, approve, implemented
4	9/15/2024	Hans Tang Vincent Roberts	Added section 5.2.7.3 c and 5.3.2 associated with CFR changes. Also provided editorial updates.
5	2/6/2025	Hans Tang Tao Xia	Review, approve, implemented

Contents

1. Document Review

- This document shall be reviewed annually for completeness
- Reviews shall be coordinated by the SCADA Engineering Department and shall include all relevant personnel.
- Revisions to this plan will be tracked using MS Word track changes feature and noted as applicable in the revision history table on page 1. If no changes are made, the annual review shall be reflected in the Revision History and the document will be re-executed by the Director of System Engineering
- This document shall be approved by the Director of System Engineering by signing and dating below.
- A DocMinder notification shall be used as an internal control to ensure timely reviews are conducted of this document.
- The latest signed copy of this page can be found in *Appendix 10 – SIGNED DOCUMENT REVIEW PAGE*

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Director, System Engineering	**Approval Date**	**Implementation Date**

2. Definitions

Approval to Energize - ERCOT approval of energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

Connectivity Nodes – Points where terminals of conducting equipment are connected together with zero impedance. A Connectivity Node is created under a Connectivity Node Group.

Connectivity Node Group – Group created under a voltage level in IMM that contains Connectivity Nodes used to connect together model elements under one substation. Connectivity Node Group number is equal to the Planning PTI Bus Number

Dynamic Rating – The current-carrying capability of a Transmission Element adjusted to take into account the effect of ambient weather conditions.

ERCOT Outage Scheduler – A web-based database and scheduling application used to create, view and edit transmission outage scheduling information.

Field Energization Date – Date that a new or modified piece of equipment will be placed in service in the field.

Good Utility Practice - Any of the practices, methods, and acts engaged in, or approved by, a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

In-Service Date – The date that new or modified equipment will be energized and placed in service in the field.

Interim Update – A NOMCR that is submitted outside of the normal 90-day submission timeline is considered an Interim Update.

Production Load Date – It is the date that the new piece of equipment first appears in the ERCOT production environment. It is a date corresponding with the energization date associated with a NOMCR and the date that new piece of equipment can initially be outaged in the ERCOT Outage Scheduler (Synonymous with Energization Date).

MultiSpeak – Standard application used to interface the SCADA system to the Distribution Outage Management System

Network Model Topology - Arrangement of electrical branches and nodes.

Node – A point at which two or more circuit elements have a common connection.

NOMCR Energization Date – The date that new or modified equipment will first appear in the ERCOT production model. Should correspond to the date the equipment will be placed in service (Synonymous with Model Ready Date).

NOMCR Request Form – A checklist used to consolidate and validate the data needed for the NOMCR finalization process. It is also used as a guide to add and configure ICCP points in SCADA.

NOMCR Outage – An outage entered in the ERCOT Outage Scheduler that is used to coordinate the energization of all new equipment in the production Environment.

NOMCR Submission Deadline – The time by which NOMCRs should be submitted in accordance with the ERCOT published schedule for model loads

Outage – The condition of a Transmission Facility or a portion of a Facility, or Generation Resource that is part of the ERCOT Transmission Grid and defined in the Network Operations Model that has been removed from its normal service, excluding the operations of Transmission Facilities associated with the start-up and shutdown of Generation Resources.

Outage Scheduler – The application that TSPs use to submit Notification of Outages or requests for Outages to ERCOT for approval, acceptance, or rejection.

Planned NOMCR Outage – Any major or minor transmission or resource facility equipment outage (other than a defined Maintenance outage) that is planned and scheduled in advance

Portmon – OpenView Port Monitor

Pseudo Point – Non-telemetered SCADA point that receives data manually through user input from OpenView.

Rating

Conductor/Transformer 2-Hour Rating

The two-hour MVA rating of the conductor or transformer only, excluding substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The conductor or transformer can operate at this rating for two hours without violation of National Electrical Safety Code (NESC) clearances or equipment failure.

Emergency Rating

The two-hour MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating for two hours without violation of NESC clearances or equipment failure.

15-Minute Rating

The 15-minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current.

Normal Rating

The continuous MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of NESC clearances.

Real-Time – The current instant in time.

SCADA Key – Unique identifier assigned to each point in the SCADA Database

TLQ – A three character field showing the highest priority Tag, Limit and Quality respectively, which currently exists on the point

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Element - A physical Transmission Facility that is either an Electrical Bus, line, transformer, generator, Load, breaker, switch, capacitor, reactor, phase shifter, or other similar device that is part of the ERCOT Transmission Grid and defined in the ERCOT Network Operations Model.

Transmission Operator – The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

Updated Network Model - A computerized representation of the ERCOT physical network topology, including some Resource Parameters, all of which replicates the forecasted or current network topology of the ERCOT System needed by ERCOT to perform its functions.

3. Acronyms

ADC	Analog to Digital Conversion
AOR	Area of Responsibility
ASOC	**A**lvin System Operations Center/ TNMP's primary control center
CFR	Cascade Facility Ratings
C_IND	Calculated Indication Point in SCADA
CIM	Common Information Model
COMM	Communications
CRR	Congestion Revenue Rights
CTX	Central Texas Region
CT	Central Texas
CT	Current Transformer
DNP	Distributed Network Protocol
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
FEP	Front End Processor
GCR	Gulf Coast Region
GC	Gulf Coast
ICCP	Inter-Control Center Communications Protocol
IMM	Information Model Manager
KV	Kilovolt
LMP	Locations-Based Marginal Pricing
M_IND	Manual indication point in SCADA
MT	ERCOT Model Tester
MVA	Megavolt Ampere

MVAR	Mega Volt-Amperes reactive
MW	Megawatt
NAMC	Notification of Anticipated Model Change Form
MAGE/SGEM	Model and Graphics Editor/Smart Grid Engineering Manager
NOMCR	Network Operations Model Change Request
NRF	NOMCR Request Form
NTX	North Texas Region
NT	North Texas
PSS/E	Power System Simulator for Engineering
PT	Potential Transformer
PTI	Power Technologies Institute software (PSSE)
PU	Per Unit
PUCT	Public Utility Commission of Texas
RICR	Rating and Impedance Change Request Form
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SDC	SCADA Database Checklist
SE	State Estimator
SOC	System Operations Center
SOE	Sequence of Events
T_CTRL	Telemetered control point in SCADA.
T_I&C	Telemetered indication and control point in SCADA
T_IND	Telemetered indication point in SCADA
T_JOG	Telemetered jog point in SCADA
TLQ	Tag, Limit, Quality

TNMP	Texas-New Mexico Power Company
TOA	Transmission Outage Administration
TRP	Type Remote Point
TSP	Transmission Service Provider
WTX	West Texas Region
WT	West Texas
XML	Extensible Markup Language

4. Intent

The intent of this document is as follows.

- To outline TNMP's NOMCR Submission Process
- To describe TNMP's procedures for:
    - Managing ERCOT Network Operations Model topology and rating change requests
    - NOMCR submission in ERCOT MAGE/SGEM
    - Managing NOMCR outages in ERCOT Outage Scheduler and changes to project energization schedules
    - Approval to Energize process for new or relocated equipment connected to ERCOT Transmission grid.
    - Managing TNMP's CFRs to ensure modeling updates are being made within the CFR.
- SCADA Database build
- SCADA Checkout Process
- ICCP Configuration and Management

5. NOMCR INFORMATION TRACKING SYSTEM (NITS)

5.1. NOTIFICATION OF ANTICIPATED MODEL CHANGE (NAMC)

5.1.1. The Notification of Anticipated Model Change, otherwise known as the NAMC, is intended to document the initial request to ASOC for an ERCOT Network Operations Model Change Request (NOMCR) submission. The NAMC serves to document the receipt of the initial request, clarifies the anticipated in-service date of requested changes, the NOMCR project scope and how it will affect topology, completion dates of required data inputs on the subsequent NOMCR Request Form (NRF), NRF completion date and the NOMCR submission date.

5.1.2. The Responsible Project Engineer or Planning Engineer shall send to the SOC Coordinator or to the designated email address a NOTIFICATION OF ANTICIPATED MODEL CHANGE (NAMC) form with required preliminary drawing(s) and/or required documents attached for all new or relocated facilities connected to the ERCOT Transmission Grid.

5.1.3. The NAMC shall be sent to the SOC Coordinator no less than 150 days prior to the anticipated in-service date, with subsequent revisions sent as soon as practicable.

5.1.4. The designated email address TNMPNOMCRs@tnmp.com was created for all NOMCR related correspondence and is used to route all NOMCR related inquiries, forms, requests and general communications inside and outside the company.

5.1.5. The SOC Coordinator shall record the NAMC receipt date on the form and save the document in SharePoint.

5.2. NOMCR REQUEST FORM (NRF) Processing

5.2.1. Upon receipt of an NAMC, the SOC Coordinator shall initiate a NOMCR REQUEST FORM (NRF) in SharePoint that will be used to gather pertinent data required for the corresponding NOMCR.

5.2.2. The SOC Coordinator shall route the NRF form to the Planning Engineer and the Responsible Project Manager via SharePoint workflow (NOMCR Submittal Flow v.1) for detailed entry as follows:

5.2.2.1. The SOC Coordinator shall pre-populate the NRF with information derived from the NAMC, known data from the preliminary drawings and supporting documents submitted with the NAMC and save it to SharePoint.

5.2.2.2. The SOC Coordinator shall assign a Responsible Project Manager and a Responsible Protection Engineer (and route the form via the SharePoint Workflow to the Planning Engineer for initial evaluation.

5.2.2.3. In support of compliance with NERC Reliability Standards associated with System Coordination, a notification of upcoming changes shall be sent to Protection Engineering for their review. These standards may include but not limited to PRC-023-6, PRC-025-2, and PRC-027-1.

5.2.2.4. The SOC Coordinator shall assign data input due dates to all contributors for the required NRF data based upon the desired in-service date and the NOMCR submission deadline.

5.2.2.5. The SharePoint Workflow process will automatically send email notifications to recipients when a Workflow Task has been assigned and data input is required.

5.2.2.6. NOMCR progress is available in SharePoint at any time to see what stage the NOMCR request is in the process.

5.2.3. The Planning Engineer reviews the initial NRF and completes the assigned task in SharePoint thereby routing the form to the Responsible Project Manager and the Responsible Protection Engineer for data input as follows:

5.2.3.1. The Planning Engineer compares the change request with the current TNMP Planning Model configuration determining what, if any, additional information is required.

5.2.3.2. The Planning Engineer shall add and highlight any additional fields and/or additional data requests in the NRF that require input by the Responsible Project Manager.

5.2.3.3. The Planning Engineer shall complete the assigned task in SharePoint and the NRF will route automatically to the Responsible Project Engineer(s) as a request for data input.

5.2.4. The Responsible Project Manager and the Responsible Protection Engineer shall complete the data inputs requested in the NRF and assigned tasks in SharePoint thereby routing the form back to the Planning Engineer for final review as follows:

5.2.4.1. The Responsible Project Manager and Responsible Protection Engineer(s) populates the required data in the sections marked Engineering Inputs

5.2.4.2. The Responsible Project Manager and Responsbile Protection Engineer attaches the required drawing package to supplement the initially supplied drawing. Required drawings may include any or all the following:

a. General 1-line
b. Electrical Plan and Section Drawing
c. Relaying 1-line
d. Transmission 3-line drawing
e. Transformer Nameplate data
f. Capacitor Nameplate data

g. Plan and Profile Drawings for all lines being added or modified

5.2.4.3. The Responsible Project Manager and the Responsible Protection Engineer completes the assigned task in SharePoint automatically routing the NRF back to the Planning Engineer for final review.

5.2.5. The Protection Engineer shall receive notification of the pending NOMCR request and will review the NRF and the attached drawings for changes in transmission, load or operating conditions that could require changes in the Protection Systems of neighboring Transmission Operators.

5.2.5.1. If changes are required the Protection Engineer will notify all associated parties of the changes required.

5.2.6. The Planning Engineer shall review the NRF and any attached supplemental drawings and finalize the required Planning Data Inputs. The Planning Engineer completes the assigned task in SharePoint thereby routing the form back to the SOC Coordinator for NOMCR submission as follows:

5.2.6.1. All required data and supporting drawings provided by the Responsible Project Manager and the Responsible Relay Engineer are reviewed by the Planning Engineer.

5.2.6.2. If additional data is required, clarification of data is needed, or if data inputs are incomplete the Planning Engineer shall attempt to reconcile the discrepancies.

a. The needed information may be collected utilizing one or more of the following methods:
   i. Verbal requests via phone conversation.
   ii. Written requests via email.
   iii. The NRF may be routed back to the Responsible Project Manager or Relay Engineer via the “Additional Data Required” Work Flow

5.2.6.3. The Planning Engineer shall update the NRF to include any data corrections, additions or clarifications.

5.2.6.4. The Planning Engineer completes the assigned task in SharePoint and the NRF is routed back to SOC Coordinator automatically for NOMCR finalization and submission.

5.2.7. Upon request, the SOC Coordinator may be requested to initiate the “Additional Data Required” Workflow in SharePoint to route a request for additional NRF data to the Responsible Project Manager or Relay Engineer..

5.2.7.1. The SharePoint Workflow process will automatically send email notifications to the designated recipients when a Workflow Task has been assigned and will specify what additional data inputs are required.

5.2.7.2. The Responsible Project Manager or Relay Engineer shall complete the Additional Data Required inputs and assigned tasks in SharePoint thereby routing the form back to the Planning Engineer for final review as follows:

a. The Responsible Project Manager or Relay Engineer updates the NRF form to include the requested data inputs
b. The Responsible Project Manager or Relay Engineer completes the assigned task in SharePoint automatically routing the NRF back to the Planning Engineer for final review.

5.2.7.3. The Planning Engineer shall review the additional data provided and shall complete the Additional Data Required task in SharePoint thereby routing the form to the SOC Coordinator for NOMCR finalization as follows:

a. The Planning Engineer shall update the NRF to include any data corrections, additions or clarifications.
b. The Planning Engineer updates the NRF with remaining equipment parameters and calculates applicable ratings and/or impedances for ERCOT modeling and NOMCR submission.
c. The Planning Engineer shall review any Facility material changes that may impact the most limiting element and update the CFR to reflect the material change.

   Note: *Facility Ratings to not apply until energization of new or modified facility changes.*

5.2.8. The SOC Coordinator receives the NRF for review, finalization and NOMCR submission.
   5.2.8.1. The SOC Coordinator reviews the NRF to ensure all data needed for ERCOT modeling is complete and either APPROVES or REJECTS the NRF.
   5.2.8.2. If the NRF is incomplete or additional data is required, the SOC Coordinator shall REJECT the form and submit a list of data requirements. The NRF will automatically route back to the Planning Engineer for the needed updates.
   5.2.8.3. If the NRF is complete the SOC Coordinator shall APPROVE the form and initiate a NOMCR with ERCOT in MAGE/SGEM.

5.2.9. The SOC Coordinator models the proposed topology changes in ERCOT MAGE/SGEM, submits the NOMCR, and completes the assigned tasks in SharePoint (See NOMCR Entry in ERCOT MAGE/SGEM section)

5.2.10. Upon completion of the NOMCR submittal the SOC Coordinator will be prompted via the workflow to input the final NOMCR submittal information.

5.2.11. The workflow will generate a notification email containing the final NOMCR submittal information and will send it to the Planning, the Responsible Project Manager and Relay Engineer indicating that the NOMCR Submission has been completed and finalized.

5.2.12. The SOC Coordinator finalizes the NRF with final comments, the NOMCR Reference Number, submission date, and the ERCOT Model Load Date.

5.2.13. The SOC Coordinator moves the NRF to the Submitted NOMCRs folder in SharePoint.

5.2.14. The SOC Coordinator updates the NAMC form with data input completion dates for each workflow stop, the NOMCR Reference Number, submission date, ERCOT model load date and change log file name.

5.2.15. The SOC Coordinator logs the submitted NOMCR information in the NOMCR Tracker on SharePoint.

5.3. RATING AND IMPEDANCE CHANGE REQUEST (RICR)

5.3.1. The Rating and Impedance Change Request form, otherwise known as the RICR, is initiated by Transmission Planning and is used to request ERCOT NOMCR submissions to align data maintained in the Planning Model and Most Limiting Series Element (MLSE) Facility information within CFR with the ERCOT Operations Model. Change requests may include Transformer and Line Impedance and Ratings, PSSE Bus Names and Numbers and Transmission Line Lengths. The form contains calculations to converts impedance values from PSSE PU to OHMs as is required by ERCOT.

5.3.2. When the Planning Engineer identifies a model change that impacts a Facility rating based on new information, the Planning Engineer will update the CFR and prepare a NAMC to reflect the model change and submit to the SOC coordinator.

5.3.3. The Planning Engineer shall notify the SOC Coordinator by submitting a NAMC with an attached RICR indicating that a change is required in the Operations model. (See Section 5.1 NAMC)

5.3.3.1. The SOC Coordinator receives and reviews the NAMC and the attached RICR and saves it in the NAMCs folder in SharePoint.

5.3.3.2. The SOC Coordinator initiates a NOMCR request with ERCOT and completes the required changes in MAGE/SGEM.

5.3.3.3. The SOC Coordinator submits the NOMCR and sends an e-mail to the Planning Engineer when the NOMCR Submission has been completed and finalized.

5.3.3.4. The SOC Coordinator updates the NAMC form with the NOMCR Reference Number, submission date, ERCOT model load date.

5.3.3.5. The SOC Coordinator moves the RICR to the Submitted NOCMR folder in SharePoint.

5.4. NOMCR Request Form (NRF)

5.4.1. The NOMCR Request form, otherwise known as the NRF, is a multi-purpose Excel form used to gather, and track required data needed for ERCOT NOMCR submissions for network model topology and rating changes. It serves as a checklist for updating, adding, configuring and validating, in SCADA and ICCP, ERCOT Operations Model changes contained in the NOMCR submission.

5.4.2. The NRF contains multiple worksheets (tabs) for where equipment data relating to specific modeled data types can be collected. A separate worksheet for the following equipment is included: Stations, Breakers/Switches, Temporary Switches and Jumpers, Lines, Loads, Capacitors, Static Var Compensators, and Transformers (DG and Auto Power Transformers). Additional worksheets for model retirement information, form revisions, notes and outage information are also included.

5.4.3. General Data

5.4.3.1. The NRF is populated with the following data:

a. Project Data
   - i. Project Form Initialize Date
   - ii. NOMCR Project Name
   - iii. ERCOT Station/Line Name
   - iv. Project Engineer
   - v. Requested Energize Date
   - vi. Targeted Model Load Date
   - vii. Project Description

b. NOMCR Submission Data
   - i. NOMCR Content Description
   - ii. NOMCR No
   - iii. NOMCR Submission Date
   - iv. Interim Update Y/N
   - v. NOMCR Model Load Date

c. Station Data
   - i. TNMP Substation Name
   - ii. ERCOT Substation Long Name
   - iii. ERCOT Station Name
   - iv. Owner/Operator

d. Planning Input
   - i. Planning PSSE Bus Number
   - ii. Planning PSSE Bus Name
   - iii. Planning Area
   - iv. Planning Zone
   - v. Latitude/Longitude
   - vi. County

5.4.4. Notes and Attachments

5.4.4.1. The Notes and Comments and Attachment section is utilized to add progress notes, log when data has been updated on the NRF and to attach related project drawings and documents. An embedded macro makes it easy to locate and attach files as needed.

a. Notes and Comments

i. Date
ii. Quick Comment Drop Down
iii. Comments

a. Attachments
   i. Date
   ii. Quick Comment Drop Down
   iii. Comments
   iv. Attachment Description
   v. Attached File Icon

5.4.5. Breakers & Switches

a. Modification to be performed
   i. Add
   ii. Chg
   iii. Del
   iv. Verify
b. Energize/Effective Date
c. Substation name where breaker or switch is located.
d. Device Owner/Operator
e. Device Number
f. ERCOT Device Number
   i. ERCOT device names are subject to ERCOT naming conventions and MAGE/SGEM character limitations. This may result in differences in device names between TNMP and ERCOT. Differences should be noted here.
g. Device Operating Type
   i. BKR
   ii. BKR-CUST OWNED
   iii. CAP SWITCHER/IPO
   iv. SWITCH
   v. SWITCH-CUST OWNED
   vi. MOTOR OPERATED CKT SW
   vii. MOTOR OPERATED DS
   viii. FUSED DS
   ix. SECONDARY DS
   x. SECONDARY FUSE
h. ERCOT Device Type is used to construct ICCP names.
   i. “CB” is pre-populated for all Breakers and Cap Switchers
   ii. “SW” is pre-populated for all Switches
i. Voltage
j. Operating Voltage (i.e. 69kv operating at 66kv)
k. Device Normal Operating State
   i. Normally Open
   ii. Normally Closed
l. Continuous Switch/BKR Rating (Amps)
m. Breaker CT Rating Factor
n. Breaker CT Max Ratio
o. Breaker CT Connected Ratio

p. ERCOT ICCP Name to be configured or verified for each switch or breaker

5.4.6. Jumpers & Temporary Switches (For Modeling Purposes Only)

a. Modification to be performed
   i. Add
   ii. Chg
   iii. Del
b. Energize/Effective Date
c. Substation name where jumper or temporary switch will be modeled.
d. Device Owner/Operator
e. ERCOT Device Number
f. ERCOT Device Type is used to construct ICCP names.
   i. "SW" is pre-populated for all jumpers and temporary switches.
g. Voltage
h. Device Normal Operating State
   i. Normally Open
   ii. Normally Closed
i. Manual Contingency Association (optional)
j. ERCOT ICCP Name to be configured or verified for each jumper or temporary switch

5.4.7. Lines

a. Modification to be performed
   i. Add
   ii. Chg
   iii. Del
   iv. Verify
b. Energize/Effective Date
c. TNMP Line Name
d. ERCOT Line Name
   i. ERCOT line names are subject to ERCOT naming conventions and MAGE/SGEM character limitations. This may result in differences names between TNMP and ERCOT. Differences should be noted here.
e. Line Owner/Operator
f. ERCOT Device Type is used to construct ICCP names.
   i. "LN" is pre-populated for all lines.
g. Line Voltage
h. ICCP Voltage
i. To Station Information
   i. To Station Name
   ii. To Station Switching Device
   iii. To Station ICCP Owner/Operator
j. From Station Information
   i. From Station Name
   ii. From Station Switching Device
   iii. From Station ICCP Owner/Operator
k. Is line Already Modeled?
   a. Current Owner Share Rating in ERCOT Model

        i. ERCOT Rating Type (Static/Dynamic)
        ii. COND Rating
        iii. 15min Rating
        iv. NORM Rating
        v. EMERG Rating
        vi. RLR Rating
    b. Current Impedance in ERCOT Model
        i. R - Resistance (in Ohms)
        ii. X - Reactance (in Ohms)
        iii. Bch-Susceptance/Charging
        iv. Length in Miles

l. Additional Owner Share Ratings
    i. OwnerShare Owner

m. OwnerShare Ratings
    i. ERCOT Rating Type (Static/Dynamic)
    ii. COND Rating
    iii. 15min Rating
    iv. NORM Rating
    v. EMERG Rating
    vi. RLR Rating

n. POI (Point of Interconnect information)
    i. Interconnecting Utility
    ii. Name of Entity
    iii. Interconnection/POI Type

o. Bus Type
p. Conductor Size and Type
q. Tower Configuration
r. Common Tower Confirmation
s. Line Length (miles)
t. TO STATION Planning Data
    i. TO STATION PSSE Line ID
    ii. TO STATION PSSE Bus No.
    iii. Most Limiting Series Element (MLSE)
    iv. TO STATION MLSE Rating
u. FROM STATION Planning Data
    i. FROM STATION PSSE Line ID
    ii. FROM STATION PSSE Bus No.
    iii. Most Limiting Series Element (MLSE)
    iv. FROM STATION MLSE Rating
v. Line Parameters
    i. Line Amp Rating
    ii. ERCOT Line Rating Type (Dynamic or Static)
    iii. Line Ratings
        1. Normal Rating
        2. Emergency (2hr) Rating
        3. Conductor Rating

4. 15-minute Rating

iv. Line Impedances
1. S Base MVA
2. Resistance – R (pu) which will be calculated to ohms
3. Reactance – X (pu) which will be calculated to ohms
4. Susceptance/Charging – B (pu) which will be calculated to ohms

w. Jointly Rated Equipment Coordination
i. Joint Equipment Company
ii. Notification sent to Interconnecting Utility
iii. Notification Method
iv. Notified Party email
v. Notification Attachment

x. TO STATION ERCOT ICCP Name to be configured or verified for each LN MW & MVAR

y. TO STATION ERCOT ICCP Name to be configured or verified for each LN MW & MVAR

5.4.8. Loads

a. Modification to be performed
i. Add
ii. Chg
iii. Del
iv. Verify

b. Energize/Effective Date

c. Substation name

d. Load Owner/Operator

e. TNMP Load Name

f. ERCOT Load Name
i. ERCOT load names are subject to ERCOT naming conventions and MAGE/SGEM character limitations. This may result in differences names between TNMP and ERCOT. Differences should be noted here.

g. ERCOT Device Type is used to construct ICCP names.
i. “LD” is pre-populated for all loads.

h. Load ICCP Voltage (used for ICCP name assignment)

i. Operating Voltage (i.e. 69kv operating at 66kv)

j. Switching device connected to the load

k. Load Type

l. Distribution Bitcoin connection
a. Addition Bitcoin Load to be Added

m. TRF Nameplate MVA xx/yy/zz

n. Planning Data
i. PSSE Bus No.
ii. PSSE Load ID
iii. Planning Load Area
iv. Planning Load Zone

o. Load Type
    i. Conforming Load-Load that varies over time
        1. Projected Average Nominal Load MW
        2. Projected Average Nominal Load MVAR
        3. Initial Load MW at Time of Energization
        4. Initial Load MVAR at Time or Energization
        5. Anticipated Date to Reach Peak Load
    ii. Non-Conforming Load-Fixed Load
        1. Initial Load MW at Time of Energization
        2. Initial Load MVAR at Time or Energization
        3. Anticipated Date to Reach Peak Load
    iii. Load Shed w/o Transmission Interruptions? (y/n)
p. ERCOT ICCP Name to be configured or verified for Load MW & MVAR

5.4.9. Capacitors and Reactors (Shunt Compensator)

a. Modification to be performed
    i. Add
    ii. Chg
    iii. Del
    iv. Verify
b. Energize/Effective Date
c. Substation name
d. Device Owner/Operator
e. TNMP Cap/Reactor Name
f. ERCOT Cap/Reactor Name
    i. ERCOT Shunt Compensator names are subject to ERCOT naming conventions and MAGE/SGEM character limitations. This may result in differences names between TNMP and ERCOT. Differences should be noted here.
g. Device Type
    i. Capacitor
    ii. Reactor
h. ERCOT Device Type is used to construct ICCP names.
    i. “CP” is pre-populated for all Capacitors
    ii. “SH” is pre-populated for all Reactors
i. ICCP Voltage (used for ICCP name assignments)
j. Switching Device Connected to the Shunt Compensator
k. SCADA MVARs to ASOC?
l. Automatic Voltage Regulation Enabled (y/n)
m. Device/Terminal Shunt Compensator is to be regulated to
n. Nominal Voltage KV
o. Nominal MVAR
p. Reactive Capability MVAR
q. Max KV to Operate
r. Min KV to Operate
s. Capacitor Sections
    i. Nominal MVAR per section
    ii. Nominal No. of Sections Switched in

iii. Max No. Sections Switched in
iv. Total No. Sections
v. Control Mode
1. Locked
2. Discrete ADJ
3. Continuous ADJ
vi. Percent Reactive Power Transfer

t. Regulating Voltage
i. Min Regulating Voltage (KV)
ii. Max Regulating Voltage (KV)
iii. Voltage Deviation Percentage
iv. Desired Regulating Voltage (KV)

u. Planning Data
i. Voltage Sensitivity – PU Voltage/MVAR
ii. PSSE Bus No.
iii. PSSE ID

v. ERCOT ICCP Name to be configured or verified for Shunt Compensator MVAR

5.4.10. Power Transformers

a. Modification to be performed
i. Add
ii. Chg
iii. Del
iv. Verify

b. Energize/Effective Date
c. ERCOT Substation Name
d. TNMP Transformer Name
a. ERCOT Transformer Name
i. ERCOT Transformer names are subject to ERCOT naming conventions and MAGE/SGEM character limitations. This may result in differences names between TNMP and ERCOT. Differences should be noted here.

b. ERCOT Device Type is used to construct ICCP names.
a. " XF" is pre-populated for all TRFs.

c. ICCP HS Voltage (used for ICCP name assignment)
d. ICCP LS Voltage (used for ICCP name assignment)
e. Current Ratings and Impedances in ERCOT if previously Modeled
f. TRF 65c rating
g. TRF 55c rating
h. SCADA TRF MW/MVAR to ASOC?
i. Where Metered
a. High Side - HS
b. Low Side - LS)

j. TRF High Side Information
i. High Side Voltage
ii. High Side Switch Name
iii. High Side Switch Rating
iv. High Side Breaker Name

v. High Side Breaker Rating
vi. High Side Jumper Type
vii. High Side CT Ratio
viii. High Side switching device contingency component flag

k. TRF Low Side Information
   i. Low Side Voltage
   ii. Low Side Switch Name
   iii. Low Side Switch Rating
   iv. Low Side Breaker Name
   v. Low Side Breaker Rating
   vi. Low Side Jumper Type
   vii. Low Side CT Ratio
   viii. Low Side switching device contingency component flag
l. LTC – Load Tap Changer
   i. LTC (y/n)
   ii. LTC KV Voltage Level
   iii. LTC Tap Position at Center of Tap Range
   iv. LTC Per Unit Step Size
   v. Step Voltage Increment (in % PU)
   vi. TRF Winding Connection Type
      1. Wye
      2. Delta
      3. Tertiary
   vii. Initial Delay for Tap Chg Operation (in sec) First Step Change
   viii. SCADA LTC Tap Position Analog to SOC (y/n)
   ix. SCADA Control LTC Raise/Lower to SOC (y/n)
   x. Automatic Voltage Regulation Enabled (y/n)
m. Regulating Voltage
   i. Min Regulating Voltage
   ii. Max Regulating Voltage
   iii. Voltage Deviation Percentage
   iv. Desired Regulation Voltage
n. Tap Changers
   i. Low Side Tap
      1. Min KV
      2. Neutral KV
      3. Max KV
      4. Normal KV
      5. Neutral Angle
   ii. High Side-No Load Tap
      1. Min KV
      2. Neutral KV
      3. Max KV
      4. Normal KV
      5. Neutral Angle
o. Transformer Step Positions
   i. Neutral Step Position

            1. Neutral Step Position Voltage
        ii. Normal Step Position
            1. Normal Step Position Voltage
        iii. Low Step Position
            1. Low Step Position Voltage
        iv. Highest Step Position
            1. Highest Step Position Voltage

p. Transformer Impedances Reflected to the LOW Side
    i. S Base MVA
    ii. Resistance – R (pu) to be converted to ohms
    iii. Reactance – X (pu) to be converted to ohms
    iv. Susceptance/Charging – B (pu) to be converted to ohms
q. Transformer Ratings
    i. A – Normal Rating
    ii. B – Emergency Rating
    iii. C – Conductor Rating
    iv. 15 – Minute Rating
    v. TRF Nameplate MVA (xx/yy/zz)
r. Planning Information
    i. TRF PSSE ID
    ii. High Side PSSE Bus No.
    iii. Low Side PSSE Bus No.
s. ERCOT ICCP Name to be configured or verified for TRF MW & MVAR
t. SCADA Keys to be linked to TRF MW & MVAR ICCP point
u. ERCOT ICCP Name to be configured or verified for TRF TAP Position
v. SCADA Keys to be linked to TRF TAP ICCP point

5.4.11. Static Var Compensator (SVC/STATCOM)

a. Modification to be performed
    i. Add
    ii. Chg
    iii. Del
    iv. Verify
b. Energize/Effective Date
c. Substation name
d. Device Owner/Operator
e. TNMP Device Name
f. ERCOT Device Name
    i. ERCOT line names are subject to ERCOT naming conventions and MAGE/SGEM character limitations. This may result in differences names between TNMP and ERCOT. Differences should be noted here.
    ii. When modeling an STATCOM the ERCOT name should indicate it is a STATCOM as opposed to an SVC. i.e. STATCOM1
    iii. When modeling an SVC the ERCOT name should indicate it is an SVC i.e. SVC1
g. ERCOT Device Type is used to construct ICCP names.

i. "SVC" is pre-populated for all STATCOMs and Static Var Compensators

h. Device ICCP Voltage (used for ICCP name assignment)
i. Switching Device Connected to SVC/STATCOM
j. SCADA MVARs to ASOC?
k. Contingency Component Flag
l. SVC/STATCOM Fixed MVAR
m. Voltage Level
n. Maximum KV
o. Minimum KV
p. Automatic Voltage Regulation Enabled (y/n)
q. Device/Terminal SVC/STATCOM is to be regulated to
r. Regulating Voltage
    i. Min Regulating Voltage (KV)
    ii. Max Regulating Voltage (KV)
    iii. Voltage Deviation Percentage
    iv. Desired Regulating Voltage (KV)
s. Capacitive Rating – Maximum available capacitive reactive power
t. Inductive Rating – Maximum available inductive reactive power
u. Shunt Admittance – B Charging (MVAR)
v. High Voltage Change Threshold
w. Low Voltage Change Threshold
x. Ramp Delay
y. Ramp Duration Threshold
z. SVC/STATCOM Control Mode
aa. Slope
bb. Percent Reactive Power Transfer
cc. Percentage Slope
dd. Voltage Set Point Voltage
ee. Post Contingency Maximum MVAR Limit
ff. Post Contingency Minimum MVAR Limit
gg. Max Time Steady State
hh. Min Time Steady State
ii. Planning Model Equivalent
jj. Planning Data
    i. PSSE Bus No.
    ii. PSSE ID
kk. ERCOT ICCP Name to be configured or verified for SVC/STATCOM MVAR
ll. SCADA Key to be linked to SVC/STATCOM MVAR ICCP point
mm. ERCOT ICCP Name to be configured or verified for SVC/STATCOM Switching Device ST
nn. SCADA Key to be linked to SVC/STATCOM Switching Device Status ICCP point

5.4.12. Electrical Bus

a. Modification to be performed
    i. Add
    ii. Chg
    iii. Del

iv. Verify

b. ERCOT Substation name where bus is located
c. Owner/Operator
d. EBUS Name - ERCOT Electrical Bus Bar Section Name
    i. An Electrical Bus must be defined at the same connectivity node that a Load is connected when:
        1. When three or more switches are attached to a single connectivity node and the node has a voltage reading
        2. When a Resource Node is associated with a connectivity node
        3. When an EPS meter is associated with a connectivity node
    ii. Electrical Bus names must be all uppercase letters
    iii. Electrical Bus names must be 12 characters or less.
e. ERCOT Device Type is used to construct ICCP names.
    i. "BS" is pre-populated for all Electric Buses
f. Bus Voltage
g. ERCOT ICCP Name to be configured under the ERCOT BusbarSection or verified for BUS KV if telemetered

5.4.13. Connectivity Nodes and Connectivity Node Groups

a. Connectivity Node Groups
    i. Connectivity Node Groups contain multiple Connectivity Nodes and must be unique.
    ii. Are assigned by Transmission Planning and represent a Planning PSSE Bus Number
    iii. Are associated with and assigned a Planning PSSE Bus Name that corresponds with the Planning PSSE Bus Number
    iv. Are separately defined for each voltage level within a substation. More than one Connectively Node Group may be assigned under the same voltage level in the same substation.
    v. Cannot span multiple substation
    vi. Must be assigned to a Planning Area
        1. "TNMP_TSP" is the Planning Area for all TNMP Connectivity Node Groups
    vii. Must be assigned to one of the following TNMP Planning Zones:
        1. TNP_BELS
        2. TNP_CLIF
        3. TNP_CLMX
        4. TNP_COGN
        5. TNP_FS
        6. TNP_GEN
        7. TNP_HC-F
        8. TNP_KTRC
        9. TNP_LEW
        10. TNP_PMWK
        11. TNP_TC
        12. TNP_VROG
        13. TNP_WC

14. TNP_WLSP

b. Connectivity nodes are points used in modeling where Terminals of Conducting Equipment are connected together with zero impedance.
    i. A unique connectivity node must be created for each terminal point of connection between modeled devices
    ii. Connectivity Node name must be limited to 4 characters
    iii. Connectivity Nodes must be associated to at least 2 terminals.
    iv. Use the one-line diagram to determine the appropriate number of connectivity nodes.

5.4.14. Retirements

5.4.14.1. The Retirement worksheets populate automatically as data is marked for deletion on other Equipment Worksheets in the NRF. The information contained in these worksheets is used as a checklist and guide for Retirement NOMCRs submittals.

a. Substation Name
b. ERCOT Device Names affected
c. ICCP Names to be removed
    i. Status ICCP Name
    ii. MW ICCP Name
    iii. MV ICCP Name
    iv. KV ICCP Name
d. Projected Retirement Date
e. Validation checkbox indicating ICCP has been removed from SCADA
f. Model Load Date retirement is effective
g. Validation Date that devices were removed from SCADA

5.5. NOMCR DRAWINGS

NOMCR Drawings are engineering drawings used to corroborate current and modified network topology and electrical designs in support of a NOMCR project.

5.5.1. NAMC Preliminary Construction Drawing

5.5.1.1. Preliminary Construction Drawings attached to the NAMC are issued by Engineering. Because the drawings are preliminary in nature, design changes up to energization may result in drawing changes. Topology changes are rare and seldom deviate from the original configuration. However, if they do occur, NOMCR changes may be necessary.

5.5.1.2. Upon receipt, the SOC Coordinator saves copies of the preliminary drawings to NOMCR Sharepoint.

5.5.1.3. The SOC Coordinator reviews the drawings for content and accuracy, playing close attention to device numbers, line names, and geographic orientation.

5.5.1.4. Drawings received for changes to existing Substations, are closely compared to existing topology modeled in ERCOT and on SCADA one-line displays.

5.5.1.5. If there are errors or omissions on the preliminary drawings the SOC Coordinator notifies the Responsible Project Engineer and Drafting

a. An email detailing the discrepancies is sent to the Responsible Project Engineer and Drafting with a request for a corrected drawing.
b. NRF Processing is suspended until a corrected drawing is received.

5.5.1.6. Once approved, the drawings can be used for NOMCR submission and SCADA Display build.

5.5.1.7. ERCOT Drawing requirements include the following for each NOMCR submission:

a. A “before” drawing depicting the existing substation configuration as seen in the ERCOT Operations Model.
b. An “after” drawing depicting the proposed Final configuration of the substation as modeled in the NOMCR.
c. Newly added devices should be clearly marked and differentiated from existing equipment also included in the drawing.
d. Future equipment can be omitted from the drawing or should be clearly marked as future.

5.5.1.8. To meet ERCOT’s drawing requirements for NOMCR submittals a copy of the preliminary drawings submitted with the NAMC shall be subsequently marked up by the SOC Coordinator to include all required ERCOT nomenclature. Drawing Markups should include the following information prior to NOMCR submission or the NOMCR may be subject to delays and/or rejection:

a. ERCOT Station Name
b. ERCOT Device Names where different from TNMP
c. All Line Names clearly indicated
d. Temporary Switch Locations, where applicable, with the normal operating state indicated
e. All Normally Open Devices Identified
f. All Points of Interconnect clearly indicated to include all Interconnecting Company Station and Line Names where applicable

5.5.2. NRF Supplemental Drawings

5.5.2.1. The following is a list of required drawings issued by Engineering that are needed to prepare the NOMCR for submission. Data contained in the drawings will be used to model and configure new equipment in MAGE/SGEM, calculate impedances and rating and to update the MLSE (Most Limiting Series Element) database maintained by Transmission Planning:

a. General 1-line drawing
b. Electrical Plan & Section Drawing
c. Relaying 1-line
d. Transmission 3 Line Drawing
e. Transformer Nameplate Data
f. Capacitor Nameplate Data
g. Plan and Profile Drawings for all Lines

5.5.2.2. It is preferred that required drawings be attached electronically to the NRF on the Notes worksheet, but can be emailed separately at any time during workflow process.

5.5.2.3. The SOC Coordinator and the Planning Engineer shall review the attached drawings for content and accuracy

5.5.2.4. If there are errors or omissions in the drawings the Project Engineer and Drafting Department are notified.

a. An email is sent detailing the discrepancies to the Project Engineer and Drafting with a request for a corrected drawing.
b. NRF Processing is suspended until a corrected drawing is received.

5.5.2.5. Once approved, the drawings are used to prepare required calculations and model new equipment in MAGE/SGEM .

5.5.3. As-Built Drawings

5.5.3.1. A notification email is sent by the Engineering Contractor to the SOC Coordinator and Transmission Planning indicating As-Built drawings are available for download from the Engineering Contractor's FTP site. In addition, an email is sent by Drafting indicating when the As-Built drawings are available for download from the Master_Cad file server in Texas City.

5.5.3.2. The Planning Engineer downloads and reviews As-Built Drawings for potential MLSE changes.

5.5.3.3. The Planning Engineers perform a True-Up procedure to account for any ratings, impedances and MLSE changes needed to previously submitted model changes.

5.5.3.4. The SOC Coordinator downloads and reviews As-Built Drawings for potential topology changes.

5.5.3.5. Any topology differences are verified with the Responsible Project Engineer and subsequently field verified.

5.5.3.6. All verified topology differences are submitted to ERCOT via the NOMCR process as a model correction for the next available Model Load.

5.6. NOMCR ENTRY IN ERCOT MAGE/SGEM

5.6.1. Model additions and changes must be coordinated with ERCOT to accurately represent the ERCOT Transmission Grid. The Network Model Change Request (NOMCR) entry process in ERCOT MAGE/SGEM begins when all data in the NRF is complete and has been finalized or upon receipt of a RICR from Transmission Planning.

5.6.2. The SOC Coordinator receives notification from SharePoint indicating the NRF is ready for finalization and NOMCR submission

5.6.3. The SOC Coordinator shall update the Operations model in ERCOT MAGE/SGEM through a NOMCR submission to reflect additions and changes submitted in NRF or RICR using the following process:

5.6.3.1. A change request summary is created in MAGE/SGEM where a NOMCR number is automatically assigned by ERCOT for a requested model load date (anticipated field energization date).

5.6.3.2. Detailed modeling is performed in MAGE/SGEM using the information from the NOMCR Request Form, Drawings, NRF and/or RICR

5.6.3.3. Planned energization dates and ERCOT model load schedule must be carefully considered when creating, modeling and submitting all NOMCRs.

a. ERCOT expects the NOMCR energization date to precede the field energization date in all circumstances.
b. ERCOT NOMCR Energization date is the earliest planned start date that can be entered for an outage on that same piece of equipment in the outage scheduler.
c. ERCOT suggests the model-ready date precede the field energization date by approximately two weeks to allow for bringing new equipment into service earlier than anticipated.
d. ERCOT suggests that field-retirement date precede the model-retirement date by approximately two weeks to allow for keeping the equipment in service past the expected field-retirement date.
e. NOMCR energization or model-ready dates for new equipment and model retirements should coincide with scheduled model loads.
f. There are 4 types of ERCOT model loads.

i. Scheduled Loads are listed in the published model load schedule located on the ERCOT web site. Scheduled loads occur weekly, usually on occurring on the first of the month. The day of the week will vary. Loads occur at 12:00 AM (00:00) on Tuesday, Wednesday or Thursday.
ii. Supplemental Loads are model loads that ERCOT deems as necessary in order to represent Network Model changes that cannot be modeled using the weekly scheduled model load. Supplemental Loads must be coordinated with ERCOT prior to submission. They are utilized at sole discretion of ERCOT. Loads occur at 12:00 AM (00:00) on agreed upon date.
iii. Emergency Loads are necessary model loads requiring modification after model has been placed into production. Emergency loads are typically used for the correction of unintentional modeling inconsistencies and are utilized at sole discretion of ERCOT. They are also used for model system restoration configurations after a storm or

hurricane that cannot be replicated with outages. Emergency loads are sometimes used for System monitoring to manage recurring congestion due to a recurring cause and to implement additional operation intervention. Emergency loads are reported to the PUCT and IMM and will be more difficult to grant and are evaluated by ERCOT in light of the following risks:

1. System conditions
2. Staffing
3. Volume of change request
4. Potential protocol obligations

iv. Downstream Production Change (DPC) is a change made to the model currently being used in Production without loading a new model. A DPC does not have to have a NOMCR energization date corresponding to a scheduled or supplemental database load.

1. DPC loads are subject to ERCOT approval and are discouraged unless absolutely necessary.
2. A NOMCR must be submitted with a DPC change
3. Requested date and comments in the description are required clearly requesting DPC consideration.
4. An email sent to NetworkModelCoordinators@ercot.com is required after NOMCR submission so that ERCOT Model Coordinators know to look for the DPC eligible NOMCR.
5. DPCs are limited to the following:
    a. Static Line Rating Changes
        i. Changes to existing ratings
        ii. Changes from static to dynamic ratings provided the new ratings are based on static temperature tables using ERCOT temperature telemetry.
        iii. Cannot add a second owner
        iv. Cannot add any new telemetry information
6. Dynamic Ratings
    i. Changes to existing ratings
    ii. Changes from dynamic to static ratings
    iii. Cannot add a second owner
    iv. Cannot add any new telemetry information
7. Breaker and Switch Status
    i. Subject to ERCOT discretion.
    ii. Cannot add any new telemetry.
8. Contingency definitions
    i. Subject to ERCOT discretion.
    ii. Each request will be examined to determine feasibility.
9. RAP and SPS Changes or Additions
    i. Subject to ERCOT discretion
    ii. Each request will be examined to determine feasibility.
10. Net Dependable and Reactive Capability values

5.6.3.4. Interim updates are NOMCRs submitted with project energize dates that are less than the required 90-day submission deadline. Requested interim updates are approved at the discretion of ERCOT. Their use should be limited to correct unintentional modeling inconsistencies, to account for system restoration conditions after a storm or to correct previously submitted impedance or rating changes. Interim updates are reported to the Public Utility Commission of Texas (PUCT) and Independent Market Monitor (IMM)

5.6.3.5. The Responsible Engineer must complete Interim Update Approval Request forms and provide the following justification for a requested Interim update if it falls under the interim update restrictions list.

a. Project Description
b. Project Scope
c. Reliability Risks for Consideration
d. Potentially Affected Entities
e. Reason for need to include Supporting documentation of a reliability risk for consideration, involving the requested change items, that demonstrates the change relieves a reliability concern. Supporting documentation may include:
    i. Reports
    ii. One-Lines
    iii. Power Point Presentations
    iv. Contingency Analysis Results
    v. Cases etc.

5.6.3.6. Interim updates shall not be approved for the following:
a. New Substations with Line-Breakers and Contingencies
b. New physical lines and Contingencies
c. New Transformers and Contingencies
d. Existing Substation with Line-Breaker and contingency reconfiguration
e. New Generation and Synchronous Condensers
f. Items requiring Resource Node additions or modification
g. New Tap Stations
h. New Shunt Compensators
i. New SVCs

5.6.3.7. Approved and annotate drawing as described in Section 5.5 corresponding to the changes modeled must be attached with the NOMCR submission.
a. Current and planned configurations must be attached to the NOMCR for each phase of the project.
b. Drawings are uploaded in the Additional Attachments section of the NOMCR change request summary in MAGE/SGEM

5.6.3.8. The MAGE/SGEM Model Editor is launched.
a. The SOC Coordinator combines the information from the NRF, RICR and NOMCR Drawings to complete the changes in ERCOT MAGE/SGEM.
b. Changes are input, viewed and validated using MAGE Tree View Panel, Schematic Diagram Panel, Attribute Panel or through ERCOT created templates.
    i. The Tree View is used to model or edit a single instance or to launch a template.
    ii. The Schematic Diagram Panel is used to view and model object layout and their respective connectivity in a one-line diagram format.
c. Changes can also be made by importing CIM XML files into MAGE/SGEM.

i. TNMP currently does not produce model changes in CIM XML format. However, ERCOT may provide an XML file when requesting special NOMCR submissions for batch changes and model corrections.

d. ERCOT developed Templates can be utilized to simplify the editing process.

i. Copies of the ERCOT developed templates can be customized with TNMP specific data and saved to the desktop for convenient reuse.

5.6.3.9. Model changes are saved and validated in MAGE/SGEM.

a. All model revisions must be saved before they can be validated.
b. All changes must be validated before the NOMCR can be submitted.

5.6.3.10. Model changes are subject to 5 levels of validation before they are loaded into production.

a. Level 1 Validation automatically occurs within the MAGE/SGEM software during data entry
   i. Verified for Accuracy
   ii. Values within range
   iii. Unique Values – no duplicates
   iv. Checks dependent attributes
   v. Topology is correct
   vi. Verified for Completeness
   vii. Associated relationships between types are satisfied
   viii. Required links are complete
   ix. Required attribute fields are completed
   x. Verified for Data Consistency
      a. Consistent naming convention
      b. Consistent schema (instance added under right parents)
b. Level 2 Validation occurs within the MAGE/SGEM software before NOMCR submission
   i. User Defined Validation
   ii. Verifies if the data as a whole is correct
   iii. Cardinality checks are performed
   iv. If validation errors occur a validation log is generated to assist with troubleshooting.
   v. All validation errors must be corrected before the NOMCR can be submitted.
c. Level 3 Validation occurs after NOMCR submission.
   i. An ERCOT Model Tester (MT) validates topology to ensure that the NOMCR is power flow ready.
d. Level 4 Validation is performed by ERCOT MT through AREVA EMS software
   i. MT will generate AREVA save cases from CIM/XML model using AREVA CIM Importer.
   ii. MT transfers it to AREVA EMS and validates that NOMCRs under test with the same energize date will pass AREVA Validation, the Powerflow and Contingency Analysis and that the changes will not corrupt any other portion of the model.
   iii. NODAL MT performs LMP Verification checking for unexpected price changes before Market Validation.

iv. CRR Auction corresponds with the completion of the Market Validation Final Validation performed by ERCOT's Energy and Market Management System group. It is the final check before the model is placed into production.

v. ERCOT checks that all final ICCP object name changes are present
   a. ICCP is re-verified by ERCOT.
   b. Failure to provide ICCP could result in emergency model loads and notification to the PUCT and IMM.

5.6.3.11. The completed NOMCR is submitted to ERCOT. ERCOT will either approve or reject the submission within 15 days from the receipt of the NOMCR

5.6.3.12. Upon successful submission to ERCOT the SOC Coordinator shall document the NOMCR submission for record retention with an attached copy of the NAMC or RICR and submitted drawings.

5.6.3.13. The SOC Coordinator shall complete the assigned task in SharePoint.

5.6.3.14. The SOC Coordinator shall input final NOMCR information as prompted by the SharePoint workflow to generate email notification to the Responsible Engineers and the Planning Engineer that the requested NOMCR has been submitted.

5.6.3.15. The SOC Coordinator shall update the required information on the NRF and RICR that was saved to SharePoint by recording the following information:

i. NOMCR number
ii. NOMCR Submission date
iii. Model load date
iv. NOMCR Submission notes

5.6.3.16. The SOC Coordinator shall update the associated NAMC form that was saved in SharePoint upon receipt by recording the following information:

i. NRF Initiation date
ii. NRF Completion Date
iii. NOMCR Submission Date
iv. ERCOT Model Load Date
v. NOMCR reference number

5.7. FINALIZATION OF NOMCR REQUEST DOCUMENTS

5.7.1. Once the NOMCR process is complete and the NOMCR has been submitted to ERCOT, finalization of the NOMCR Request Forms and supporting documents is necessary for compliance purposes.

5.7.1.1. The SOC Coordinator shall move the NRF and RICR to the Submitted NOMCRs folder in SharePoint

5.7.1.2. The SOC Coordinator shall update the NOMCR Tracker in SharePoint by recording the following information for metrics tracking:

a. Change Log File Name
b. NOMCR Number
c. Energize Date
d. Station or Line Name

e. Description of submitted NOMCR
f. BES Y/N
g. FAC-008 Y/N
h. Change Type
i. Requesting Engineer
j. Date NAMC and Initial Drawing or Email Received
k. Earliest available Energize Date based on requested energize date
l. NRF Routing Process Start Date (if NO Workflow was used)
m. Date NRF was routed to Planning for Initial Review
n. Date NRF was routed to Project Engineer for Inputs
o. Date NRF completed and Routed to SOC for finalization
p. Start Date for Coordination of POI with Interconnecting Utility (if applicable)
q. End Date for Coordination of POI with interconnecting Utility (if applicable)
r. NOMCR submission date
s. Model Load Date for Submission as requested on NAMC
t. Interim Update Y/N
u. Interim Update Exemption Y/N
v. Reason for Interim Update Exemption
w. Reason for Delays and/or Interim Update
x. PUC Reportable Interim Update (Y/N)

5.7.1.3. The following information is calculated in the NOMCR Tracker based upon the information entered for each NOMCR submission.

a. Calculated Number of Days for Planning to Complete Initial Review
b. Calculated Number of Days for Engineering to Provide Required Data
c. Calculated Number of Days for Planning to Complete Final Review
d. Calculated Number of Days Submission for Routing Time
e. Calculated Number of Days to Coordinate POI with Interconnecting Utility
f. Calculated Number of Days for the SOC Coordinator to Prepare and Model in MAGE/SGEM
g. Average Number of Days the SOC Coordinator requires for Workflow Preparation, Workflow Routing and Modeling
h. Average Number of Days the SOC Coordinator NOMCR Prepare and Route Workflow
i. Average Number of Days the SOC Coordinator to Complete Modeling in Mage/SGEM
j. Average Number of Days NOMCR submitted before Model Load Date
k. Average Number of Days NOMCR Routing Time
l. Average Number of Days Planning Initial Review
m. Average Number of Days Engineering Inputs
n. Average Number of Days Planning Final Review
o. Average Number of Days for POI Coordination with Interconnecting Utility
p. Percentage of Interim Update Violations Reported to PUC
q. Percentage of NOMCRs submitted within the 90 Day Requirement
r. Total Number of NOMCRs submitted for the year

5.8. NOMCR OUTAGES

5.8.1. NOMCR Outages are used to coordinate field construction schedules and the model-ready date for new and retired equipment.

5.8.1.1. The ERCOT Outage Scheduler serves as the primary tool for entry of NOMCR Outages.

5.8.1.2. The field energization date is the date new equipment is energized in the field and is ready for normal service.

5.8.1.3. The field retirement date is the date that a device is de-energized in the field in order to be permanently removed from service.

5.8.1.4. The model-ready date is the date that a device first appears in the ERCOT production environment and is the earliest planned start date that can be entered for an outage on that same piece of equipment in the Outage Scheduler.

5.8.1.5. The SOC Coordinator shall enter Planned NOMCR outages in the ERCOT Outage Scheduler for all new and retired equipment. If multiple outages are required, each outage must be clearly identified including sequence of Outage and estimate of Outage duration. New equipment should be outaged in its normal operating state. Telemetry is not required prior to the Approval to Energize, but if status is provided, then it must reflect the normally modeled state (that is expected to result in similar power flows between the physical & modeled state). Any modeled future equipment must have a telemetered status state that doesn't cause the ERCOT model to be significantly different from the physical flows.

5.8.1.6. Planned NOMCR outages on new equipment are possible only after the new equipment is modeled in MAGE/SGEM. Future equipment will be available in the Outage Scheduler seven calendar days after the NOMCR is submitted.

5.8.1.7. Relocated equipment that is moved from one location to another, or is re-energized in a new configuration in the same substation is subject to the Approval to Energize process and must be entered in the Outage Scheduler

5.8.1.8. Lack of planned outages in association with new equipment energization may result in the increased withdrawal of approval for previously approved outages.

5.8.1.9. If a project is delayed (not more than 45 days), and model corrections are not possible and/or desired, ERCOT will review the differences expected between the Phyiscal vs Modeled power flows. If there is less than 10 MVAR flow differences, then it is possible to allow for the physical single line to be represented in the model as the two future lines. ERCOT's model of flow on future lines is used as an equivalent to the physical line. Modeled flow (that might include effects of the non-connected future conductor between a new substation) does not constitute an Approval to Energize on this future equipment. Rather, it is ERCOT's determination that differences are acceptable for a time period of the project delay.

5.8.2. ERCOT will send an email indicating any New Equipment that needs to be entered in the Outage Scheduler. The email is a courtesy notification indicating the NOMCR has been completed and provides a list of equipment that will be added to the ERCOT model.

5.8.3. The SOC Coordinated submits a Planned Outage in the Outage Scheduler for each device listed in the email using the following parameters:

a. Nature of work indicated as "New Equipment Energization"
b. Planned Start as Midnight (00:00) on the in-service date

c. Planned End as the expected field energization date.

5.8.4. The SOC Coordinator will document the NOMCR outage for record and file it in a reminder folder for the month in which the NOMCR outage will expire.

5.8.5. The SOC Coordinator will set a reminder in Outlook to review the NOMCR outage 3 to 7 days prior to expiration.

5.8.5.1. Upon reminder the SOC Coordinator will contact the Project Engineer (3 to 7 days prior to expiration) to request an updated project status.

a. If the project is on schedule to energize the SOC Coordinator shall contact ERCOT for preliminary Approval to Energize (see Approval to Energize process)

b. If the project is not on schedule to energize the SOC Coordinator will requests an updated field energization date from the Project Engineer. (see Change in Energization Schedule process)

5.9. CHANGE IN ENERGIZATION SCHEDULE

5.9.1. Any changes in the project Field Energization Schedule shall be communicated to the SOC Coordinator as soon as practicable.

5.9.2. Each time a change in the NOMCR energization schedule occurs the Project Engineer shall notify the SOC Coordinator and provide a new anticipated in-service date and the reason for the change.

5.9.3. Upon receipt of the information the SOC Coordinator reviews the state of the pending NOMCR to determine what course of action is available to adjust the energize date.

5.9.4. ERCOT tracks each NOMCR submittal in accordance with Nodal Protocols and will notify via email when each requested NOMCR is processed and at each stage it is being implemented. A NOMCR will be in one of the following states:

a. Received – ERCOT has received the submitted NOMCR
b. Approved for Testing – NOMCR has enough information to begin testing
c. Incomplete – NOMCR does not have enough information to begin testing
d. Additional Data Required – ERCOT is waiting for more data from SOC before the NOMCR can be Approved for Testing
    i. If there are any deficiencies in the submittal for changes in system topology or telemetry, ERCOT will notify the SOC Coordinator.
    ii. ERCOT will contact the SOC Coordinator by email or phone requesting addition data.
    iii. The SOC Coordinator will provide additional data as soon as possible upon request
e. MP Test Period Complete – The NOMCR has been submitted in the Market Test Model and it has survived the Market Test as well as the Level 4 test. The timeline is now 15 days from the 1st day of the moth in which the NOMCR energization date occurs.
f. Approved for Production – The changes have been tested and if all things go according to plan, the NOMCR should not cause any issues when going in to production.
g. In Production – The change has actually made it to the Production Model
h. Closed – The NOMCR has been added to Production and was “energized” successfully. The NOMCR is no longer active. Any changes in the field energization schedule after this point are managed in the outage scheduler (See section on NOMCR Outages).

5.9.5. The SOC Coordinator shall update the NOMCR energization date contingent on the current state of NOMCR

5.9.5.1. NOMCR can be updated with a new NOMCR energization date in MAGE/SGEM when it is in the following states:

i. NOMCR Received – The SOC Coordinator is able to change the energize date and resubmit the NOMCR. Changes at this point may result in an interim update if submitted less than 90 days from NOMCR energization date.
j. NOMCR Approved for Testing – The SOC Coordinator may contact ERCOT presenting required changes needed for the NOMCR. If possible, ERCOT will change the status to Received so changes to the NOMCR can be made and resubmitted. Otherwise, the SOC Coordinator will update the NOMCR outage in ERCOT Outage Scheduler to reschedule the field energization date.

5.9.5.2. The related NOMCR outage must be updated with new field energization date by submitting a new Planned Outage End Time in ERCOT Outage Scheduler based on information provided by the Project Engineer when in the following states:

a. NOMCR MP Test Period Complete – Changes have been tested and the NOMCR cannot be changed.
b. NOMCR Approved for Production – Changes have been tested and the NOMCR cannot be changed.
c. NOMCR In Production – The model has been updated to production and changes to the NOMCR cannot be made. A new NOMCR will need to be submitted or the outages scheduler needs to be updated.
d. NOMCR Closed – Changes have been added to the production model. A new NOMCR will need to be submitted or the outage scheduler needs to be updated.

5.10. APPROVAL TO ENERGIZE PROCESS

5.10.1. Approval to Energize is the process by which ERCOT verifies and grants authorization to energize and place in service new and relocated equipment.

5.10.2. Prior to energizing and placing into service any new or relocated facility connected to ERCOT Transmission Grid, Model Coordinator shall coordinate with and receive approval from ERCOT.

5.10.3. Energization of new equipment in the ERCOT production environment will be preceded by two conditions. First, the equipment must be modeled in its normal state. Secondly, a Planned Outage whose end time corresponds with the energization of the new equipment must be entered in the Outage Scheduler.

5.10.4. ERCOT Operations will check the outage scheduler on a daily basis for equipment that is to be energized within seven days.

5.10.5. Equipment that is reported ready for energization will be verified for connectivity and ICCP communications.

5.10.6. ERCOT shall perform the following before granting approval to energize:

5.10.6.1. ERCOT checks for and investigates equipment that is reported as ready for field energization within seven days.

5.10.6.2. If no problems are anticipated and the verified equipment meets Approval to Energize standards, ERCOT will send an Approval to Energize Notification email stating that the Approval to Energize is expected to occur as scheduled and that no problems are anticipated.

5.10.6.3. If upon investigation a problem is found ERCOT will send an Approval to Energize Notification email detailing the problem and will indicate that the Approval to Energize could be delayed if problems are not fixed prior to field energization date. ERCOT must be notified when the problems have been corrected

5.10.6.4. If the new equipment is not found in the current production model the Approval to Energize notification email will indicate Approval to Energize may be delayed. ERCOT must be notified with details as to when the equipment is expected to be loaded into production.

5.10.6.5. ERCOT Operations will notify ERCOT Shift Supervisor of expected field energization dates and recommended actions. If ERCOT Shift supervisor or designee and ERCOT Operations are in agreement approval will be granted.

5.10.7. Written Notice of Approval from ERCOT must be received before placing equipment in service.

5.10.8. In addition, System Operator approval by phone from the ERCOT Shift Supervisor for the activation of any new or relocated transmission facility is required on the day of field energization.

5.11. PROJECT ENERGIZATION

5.11.1. Field Energization can only occur once ERCOT has issued approval and SCADA checkout has been completed. See section Approval to Energize for details.

5.11.2. Upon energization the Outage Coordinator shall end NOMCR outages in ERCOT Outage Scheduler

5.11.2.1. The Outage Coordinator provides required Actual Outage End Time

5.11.2.2. The Outage Coordinator provides required supporting statement.

5.11.3. "As Built" drawing notifications from drafting and Engineering Contractors are sent to Planning Engineer for final MLSE Verification and True UP

5.11.4. SCADA Analog values on all affected equipment are re-verified for accuracy after field energization.

5.12. CONTINGENCY MANAGEMENT

5.12.1. Contingencies Definitions

5.12.1.1. A Contingency is defined as "An event threatening system reliability, consisting of one or more Contingency Elements". A Contingency element is an element of a system event to be studied by contingency analysis, representing a change in status of a single piece of equipment. Breakers and switches are examples of contingency elements.

5.12.1.2. Contingencies are modeled to study the "What-if" situations. They are defined on Lines, Power Transformers and generating units which are likely to affect the system reliability in case of a forced outage. ERCOT's Network Security Analysis application is used to gauge contingency impacts before they occur and alert the ERCOT operator to any potential overloads or serious voltage violations.

5.12.2. Base Contingencies

5.12.2.1. The initial set of Base Contingencies are loaded by ERCOT and programmatically generated breaker-to-breaker between "seed" Equipment. i.e. Auto Transformers, Non-radial AC transmission lines, Shunts, SVCs, Series Compensators or between a generator and it's high-side breaker.

5.12.2.2. It is assumed that Breakers are the only devices in the model which can break current, and under steady state isolate a faulted element or elements. In certain situations, however the typical criteria may not be how the topology is represented under steady state conditions. In these cases, special modeling considerations must be made in order to properly represent steady-state configuration of the grid under contingency.

5.12.2.3. The Contingency Component Flag (CCF) in the ERCOT Operations Model identifies how a modeled transmission element should be handled during contingency analysis.

5.12.2.4. The CCF is used to modify the contingency definition. If the default flag assignment on a new breaker or switch device does not correctly simulate the expected contingency, Market Participants are expected to set the flag to a state where the correct contingency can be built.

a. Breakers – The CCF is set to true if the breaker is controlled by relay action and will open in the event a fault. A false setting for the flag indicates the breaker will not operate in response to a fault
b. Disconnects and Switches – The CCF is set to true to indicate a switch will not operate in the event of a fault. The flag should be set to false if the switch will operate in response to a relevant fault. ERCOT defines switch action that occurs automatically, within 60 seconds of the fault to be modeled with the CCF set to false. Operator switching is not considered to be automatic

5.12.2.5. Normal Open Flags and Initially Open Flags combined with the CCF affect how a modeled transmission element should be handled during contingency analysis.

a. Breakers that are defined as Normally Open (N.O.) that have the CCF set to true indicate the breaker will not operate under fault.
b. Disconnects and Switches defined as Normally Open (N.O.) that have the CCF set to true or false indicate the it will not operate under fault. A normally closed disconnect or switch with CCF set to false will indicate a fault isolating device.

5.12.2.6 SOC Coordinator is expected to work with ERCOT to identify equipment that should be added to or deleted from a contingency. Since ERCOT's programmatic contingency generator has the capability to exclude contingencies on previously identified equipment, the SOC Coordinator is expected to notify ERCOT of any changes to defined contingences.

5.12.3. Manual Contingencies

5.12.3.1. Manual Contingencies are Special modeling considerations made in order to support downstream systems' contingency analysis processes and are needed to cover situations in which future equipment won't energize on a database load.

5.12.3.2. When Temporary Switches are modeled in a NOMCR to isolate new equipment until energization, a Manual Contingency definition is required to change the list of base auto-traced contingencies. A Manual Contingency definition ensures that the Temporary Switch statuses are used by the Contingency Analysis software when determining the steady-state configuration of the grid.

5.12.3.3. Manual Contingencies are submitted by Market Participants using CAMRs. ERCOT will coordinate with the SOC Coordinator to define the list of single elements for a new Manual Contingency.

5.12.3.4. The SOC Coordinator will submit a CAMR to request the new Manual Contingency be added to the Operations Model. ERCOT will approve or reject the CAMRs and notify the SOC Coordinator. The approved changes will be modeled by ERCOT in the Network Operations Model.

5.12.3.5. The SOC Coordinator will submit a CAMR to request a Manual Contingency be Enabled. The CAMR must clearly communicate what Manual Contingency is to be enabled and if applicable which Base Contingency is to be disabled until the new equipment is energized.

5.12.3.6. When the new equipment is energized the SOC Coordinator will submit a CAMR to request a Manual Contingency be Disabled. The CAMR must clearly communicate what Manual Contingency is be disabled and if applicable which Base Contingency is to be re-enabled.

5.12.3.7. The SOC Coordinator will submit a CAMR requesting a Manual Contingency be Removed when equipment has been energized, a clean-up NOMCR has been submitted to remove associated temporary switches and it is no longer needed. The CAMR should be submitted with the same production load date as the submitted clean-up NOMCR. ERCOT will remove the Manual Contingency from the Operations Model.

5.12.3.8. Requests to add, enable or disable contingencies should be submitted for the next available database load. If a Manual Contingency is required within one to three days to mitigate model changes that have already loaded or equipment that has already energized a DPC (Down Stream Production Change) may be requested.

5.12.3.9. ERCOT Operations must be notified at least one hour prior to enabling or disabling a Manual Contingency that has been submitted for DPC. Notification in writing to the ERCOT Shift Supervisor is expected to include the name of the contingency and action required.

5.12.3.10. If the implementation of a Manual Contingency is delayed or postponed, the SOC Coordinator will notify the ERCOT Control Room and work with ERCOT Modeling to reschedule any CAMRs/NOMCRs needed.

5.12.3.11. If a DPC CAMR is required after normal business hours (evenings, weekend or holidays) the SOC Coordinator must submit the DPC request and notify the ERCOT Control Room of the submitted CAMR number and follow-up the next business day with ERCOT Modeling.

5.12.4. Double Element Contingencies

5.12.4.1. A Double Element Contingency is required for lines that share a common structure for more than or equal to one half mile.

5.12.4.2. SOC Coordinator shall proactively communicate to ERCOT which equipment should be included in a double circuit contingency. Any model changes that result in the creation or removal of one or more new double contingencies should be submitted with identification of which elements create each of the new double contingencies. The information will be used to update the contingency list in the ERCOT Operations Model.

5.12.4.3. An annual agenda item is added to the Network Data Support Working Group (NDSWG) meetings to review the current list of double elements and verify that the list is complete.

5.12.4.4. ERCOT will distribute the list to Market Participants of all identified Double Element Contingencies on an annual basis. The SOC Coordinator will review and confirm the list of Double Element Contingencies and if required submit a CAMR for any updates to the list. If there are no changes required, an ICR is submitted stating that no updates are needed.

5.12.4.5. A CAMR can be submitted to ERCOT to update Double Element Contingencies at any time. Updates should include only “seed elements” and should not include temporary switches or any other devices.

6. SCADA DATABASE

6.1. SCADA DATABASE

6.1.1. SCADA Database Configuration is the functional arrangement by which monitored equipment on the TNMP electrical system is stored in the SCADA Database to facilitate effective and accurate monitoring, control and situational awareness of TNMPs transmission and distribution system by System Operators. All new equipment added to the transmission and distribution system requires configuration in SCADA database and on SCADA displays.

6.1.2. Required data for SCADA database configuration data is combined from two primary sources; Communications Point List and ASOC SCADA DB Standards.

6.2. SCADA POINT LIST

6.2.1. Communications will provide initial and updated configuration data needed to achieve and maintain proper communications and connectivity with all remote field devices. Initial database information is provided in the form of a points list containing required information for a Database Build. Communications provides the following information in a spreadsheet form referred to as the SCADA Points List.

6.2.2. RTU Information

a. Protocol Type
   i. The following Protocols are used by TNMP:
      1. DNP
      2. SERIES 5
      3. TELEGYR
   ii. Protocol Sub Type is assigned as follows:
      1. Series 5 subtype = standard
      2. Telegyr subtype = 8979
      3. DNP subtype = none
b. RTU Type
c. IP address
   i. The RTU IP address is assigned by Communications.
d. TCP/UDP Port Number
e. Master Station Address
f. Station Hardware (RTU) Address
g. ADC count for min/max signal
   i. The following are assigned for each protocol:
      1. DNP = +/- 32767
      2. Series 5 = +/-2000
      3. Telegyr = +2048/-2047
h. Comments

6.2.3. Points Information

a. Telemetered Status Point configuration data for SCADA mapping of all configured points.
   i. Status point count
   ii. Point hardware mapping
   iii. Point name
   iv. States names (i.e. open/closed)

- v. Normal point state
- vi. RTU Mapping Data
  1. Device Type
  2. Port
  3. Comm Type

b. Telemetered Analogs Point configuration data for SCADA mapping of all configured points:
- i. Analog point count
- ii. Point hardware mapping
- iii. Point name
- iv. Engineering units
- v. Max Range (reasonability)
- vi. OSI Multiplier based on max range, CT and PT ratios
- vii. RTU Mapping Data
  1. Device Type
  2. Port
  3. Comm Type

c. Telemetered Accumulator Point configuration data for SCADA mapping of all configured points:
- i. Accumulator point count
- ii. Point hardware mapping
- iii. Point name
- iv. Engineering units
- v. Units per pulse ratio
- vi. RTU Mapping Data
  1. Device Type
  2. Port
  3. Comm Type

d. Telemetered Control Point configuration data for SCADA mapping of all configured points:
- i. Control point count
- ii. Control point address
- iii. Control point name
- iv. Control types
  1. Latch
  2. Pulse
  3. Jog

6.3. SCADA DATABASE CHECKLIST (SDC)

6.3.1. The SCADA Database Checklist (SDC) provides a check-list for database and display configuration activities associated with SCADA on new or relocated transmission and distribution field equipment.

6.3.2. Upon receipt of a SCADA point list from Communications the SCADA DBA will initiate a SCADA Database Checklist for the project.

6.3.3. If needed, the SCADA DBA will assign the following:

a. OSI RTU Name
b. OSI RTU Number
c. OSI Station Name

d. OSI Station Number
e. RTU Type
f. Protocol
g. IP Address
h. Port Number
i. OSI Channel #
j. Station Hardware Address
k. Database Build in Explorer Checkbox
l. Database Rollout Checkbox
m. Project/Change Description
n. Completion check boxes verification for old and new configurations on the following:
    i. FEP Configuration Data
    ii. RTU Configuration Notes
    iii. Status Configuration
    iv. Analog Configuration
    v. Accumulator Configuration
    vi. Control Configuration
    vii. MVA & Power Factor Configuration
    viii. TOA/MultiSpeak Configuration
    ix. Display Configuration
    x. Bus Net Points
    xi. Flat Line Points
    xii. Alternate Data Source Points
o. Distribution CKT Trip Setting Notes
p. MultiSpeak Configuration Notes
q. ICCP Configuration Notes
r. ICCP Pts Verified Updating with ERCOT check box
s. Date ICCP Verified with ERCOT
t. Notes/Action Items/Follow-Up Notes
u. Model Data SCADA line ratings verification check box
v. Model Data SCADA Limits Updated verification check box
w. Model Data SCADA Limits Updated Date

6.4. FEP CONFIGURATION

6.4.1. RTU Configuration

6.4.1.1. The SCADA DBA combines the information provided by Communications in the points list with the following additional information established through internal standards and builds the SCADA database.

a. RTU Number
    i. The RTU is a microprocessor-controlled device that interfaces field devices to the SCADA system by transmitting telemetry data to the OSI master allowing for the remote control and monitoring of connected devices. The RTU may be interfaced to multiple Intelligent Electronic Devices (IEDs) (i.e. Relays) to poll information. For SCADA purposes all devices used to poll information for monitoring and control is categorized and referred to as an RTU.

   ii. RTU Number is assigned by the SCADA DBA from the list of blank available RTU Numbers.
   iii. There can be more than one RTU assigned to a SCADA Station, however the RTU Name should be unique.
   iv. Unique record number in FEP

b. RTU Name
   i. A unique RTU Name is assigned to an RTU Number and represents a single polling device.
   ii. The unique RTU Name is used for log files and alarms
   iii. Names should be between 1 – 12 characters in length.
   iv. If there is more than one RTU assigned to a SCADA Station, the second and subsequent RTU Names assigned will have the same name as the first RTU but with "_2", "_3" etc. appended to the end of the name (i.e. Heights, Heights_2). The appended "_2" notation at the end satisfies the unique naming requirement.

c. RTU Abbreviation – currently not used; do not implement.
   i. Optional. If provided the FEP keys generated for the RTU will use the abbreviation instead of the one generated from the RTU record number

d. RTU Protocol
   i. Defines the message format used to communicate with an RTU (provided by Communications)
      1. DNP
      2. Series 5
      3. Telegyr
   ii. Protocol Sub Type may be required for some protocols.
      1. DNP subtype = none
      2. Series 5 subtype = standard
      3. Telegyr subtype = 8979

e. Station Address
   i. Numeric address the protocol uses to uniquely identify each RTU on a channel.

f. RTU Point Definitions (corresponds to point counts provided on Communications Point List)
   i. Point type = Protocol specific parameter that indicates the type of points in the given block
   ii. Start = First point number defined in the block
   iii. Count = The number of points defined in the block

g. Error History Percentage-Determines the thresholds at which an RTU is considered ONLINE or FAILED
   i. Good =5%
   ii. Fail=75%
   iii. No. of scans = 100 (To base the percentage calculations on)
   iv. Consecutive Error Limit Definition=30
   v. RTU is considered failed when the percentage failure limit is reached or when the consecutive error limit is reached, whichever occurs first.
   vi. The RTU will be considered ONLINE again when BOTH percentage failure limit AND the consecutive error limit recover.

h. Delay Unit definitions
    i. Request Delay = 0 for all protocols
    ii. Response Delay varies for each protocol and installation
        1. DNP = 500
        2. Series 5 = 1000
        3. Telegyr = 1500
i. IP Manager Connection timeout setting for RTUs assigned to a channel managed by the IP Manager.
    a. Conn timeout = 250
j. Internal indications
    i. Class 1 Data Available = yes
    ii. Class 2 Data Available = yes
    iii. Class 3 Data Available = yes
    iv. Time Sync Required = no
    v. Some Controls in Local State = no
    vi. Device Trouble = yes
    vii. Device Restart = yes
    viii. Invalid Function Code = yes
    ix. Invalid Object = yes
    x. Invalid Message Format = yes
    xi. Event Buffer Overflow = yes
    xii. Request already executing = yes
    xiii. Corrupt Configuration = yes
k. Initialization Scan Definition
    i. Scan Type/GSD
        1. DNP
            a. 4=Class 0 Scan
            b. Datalink Service = 65535
        2. Series 5
            a. 1=Analog Scan
            b. 3=Status Point Scan
            c. 12=RTU Config Request
            d. 29=SOE Time Sync
        3. Telegyr
            a. 15=Time Synch
            b. 6=Indication Force Report
            c. 3=Analog Force Report
            d. 8=SOE Force Report
            e. 10=Accumulator Freeze
                i. Count
                ii. Retries=1
l. Demand Scan Definition
    i. Scan Type/GSD
        1. DNP
            a. 11=DNP Restart
        2. SERIES 5
            a. 1=Analog scan

b. 3=Status point scan
3. Telegyr
   a. 15=Time Synch
   b. 6=Indication Force Report
   c. 3=Analog Force Report
   d. 8=SOE Force Report
   e. 10=Accumulator Freeze
   f. Count
   g. Number of retries

m. Periodic and Idle Scan Definitions
   i. Scan Type/GSD
      1. DNP
         a. 29=Status Binary SOE
         b. 32=Status Class 0 Data
         c. 28=Analog [16bit]
         d. 3=Accums
      2. Series 5
         a. 1=Analog Scan
         b. 3=Status Point Scan
         c. 12=RTU Config Request
         d. 29=SOE Time Sync
      3. Telegyr
         a. 6=Indication Force Report
         b. 3=Analog Force Report
         c. 8=SOE Force Report
         d. 15=Time Sync
         e. 10=Accumulator Freeze
            i. Count
            ii. Number of retries

n. Global Scan Definition is preconfigured for each Scan type
   a. Retries
   b. Attempts

6.4.2. Scan Definitions

6.4.2.1. Scans have traditionally been defined independently on each RTU on a scan-by-scan basis. Standard and Enhanced scan definitions are used at TNMP.

a. Standard Method of Defining Scans
   i. Requires each scan to be defined individually for each scan type.
   ii. Telegyr and Series 5 Protocol Specific at TNMP
   iii. Initialization, periodic and scan parameters must be entered independently on each of the corresponding displays for the specified RTU.
      1. Scan Type
      2. Function Code
      3. Retries-The number of additional, immediate scans that must fail before the openfep process marks the associated point as bad quality. Retries go out immediately and add additional traffic on the channel.

4. Attempts-The number of successive periodic scans that must fail before openfep marks the associated point as bad quality. Attempts do not add additional traffic on the channel.
5. Start-The openfep process begins reading data from the starting address
6. Count-The number of points to read
7. Global Scan Group
8. Parameters

b. Enhanced Method of Defining Scans
   i. Global Scan Definition records are created to link each desired scan to it.
   ii. DNP Protocol Specific at TNMP
   iii. Initialization, Periodic and scan parameters are entered once on the Global Scan Definition and linked to each of the Scan Types
   iv. A single Global Scan Definition record contains all possible scan options for the specified protocol
      1. Protocol
      2. Name
      3. Function Code
      4. Object/Variation
      5. Normal Scan Parameters
         a. Global Scan Group
         b. Attempts
         c. Retries
      6. Post-Ctrl Scan Parameters
         a. Delay
         b. Duration
         c. Period
      7. Point Parameters
         a. Start
         b. Count
      8. Misc. Parameters
      9. Datalink Service
      10. Analog Output Export Groups
      11. Link – Allows multiple scans to be issued in sequence. Maximum number of linked scans is 10. Only applies to scans issued via an RTU action or channel action. (not used)
      12. Parameters for Reads for Static Data
         a. Prefix reads for Class 1 Events
         b. Prefix reads for Class 2 Events
         c. Prefix reads for Class 3 Events
      13. File Parameters
         a. File Name

6.4.2.2. TNMP Global Scan Definitions (see FEP System Config for details on each definition)

a. DNP Analog Scans : 4 seconds
b. DNP Status Scans : 3 minutes
c. DNP-Binary Counter [16bit]-VAR 2 – Rate 5 min
d. DNP Class 0 Scan : Initialization

e. DNP Osiris Analog Scan : 4 seconds
f. DNP Osiris Accumulator Scan : 5 minute
g. DNP-Binary Counter [32bit]-VAR 2 – Rate 5 min
h. DNP Restart Cmd
i. DNP Read Internal Indications
j. DNP Enable USM Class 1 Data – Sage 1330: 1 min
k. DNP Accumulator Scan – Sage 1330 : 5 minutes
l. DNP Read Internal Indications – 4 seconds
m. DNP Disable USM: Class 1 Data
n. DNP-Analog in [16bit] – VAR 2-Rate 10 sec
o. DNP-Binary Input [SOE] – VAR 2 – Rate 4 sec
p. DNP-Binary Input [IND] – VAR 2 – Rate 4 sec
q. DNP-Binary Input [ANY] – VAR ALL – Rate 4 sec
r. DNP-Binary Input [ANY] – VAR ALL – Rate 1 min
s. JEMStar Integrity Scan – Rate 1 min
t. JEMStar Analog Scan – Rate 10 sec
u. JEMStar Accum Scan – Rate 5 min

6.4.3. SCADA Channel Configuration

6.4.3.1. A channel is defined as a single communication path to an RTU. Channels are primarily configured and maintained from the Channel Configuration display. Every OpenFEP process uses a hostname and a port number to establish a socket connection for communication. Typically, the socket connects to a single port on a communication server, but it is possible for the socket to connect directly to a TCP/IP ready RTU.

a. If the channel is a single port on a communication server (FEP) a FEP record number corresponding to a defined Host Name is assigned. The PORT field entered is the physical port number on the communication server used to create a TCP/IP socket number that is appropriate for the type of communication server in use.
b. If a communication server (FEP) is not defined a TCP/IP address can be entered directly in the Hostname field. The PORT field then becomes the TCP/IP socket number needed to create the socket connection.
c. Channel can have multiple RTUs assigned but all RTUs being polled on the same channel must be the same protocol.

6.4.3.2. OpenFEP Channels – Channel that runs on one instance of the OpenFEP process and is responsible for servicing a single channel. OpenFEP schedules and formats all scan and control messages from the master station. It sends the messages over the channel to the proper field device. It reads replies from the field devices, extracting the replies of field devices and updating the FEP and SCADA databases with the new data. OpenFEP Channels are defined as follows:

a. Hostname = IP address or OpenFep host name of the associated FEP record number of the communication server.
    a. If a FEP is not defined for a channel you can enter the hostname directly into the field on the Channel Detail display.
b. Port # = physical port number on the communications server or a TCP/IP socket number that is appropriate for the type of communication server that is in use.
c. Protocol

        i. DNP
        ii. Series 5
        iii. Telegyr
    d. Channel timing
        i. Request Delay = 0 ms
            1. Configures a delay between receiving a response and issuing the next request.
        ii. Response Timeouts = 200 ms
            1. Determines timeouts for scan attempts
        iii. Connection Timeout = 250 ms
            1. Maximum amount of time to wait for a connection request to succeed when attempting to establish an IP connection.
        iv. No Reply Limit = 120 scans
            1. Determines the maximum number of successive failed scan attempts before it takes corrective action.
        v. Baud Rate = 9600 or 1200
            1. Defines the speed of the slowest link in the serial communication path on the channel. (data provided by Communications)
        vi. Data Bits = 8
            1. Defines the number of data bits in a byte. Typically, there are eight data bits in a byte, but it varies by protocol.
        vii. Stop Bits = 1
            1. The number of bits that are appended to a byte for framing
        viii. Parity = OFF
            1. The parity bit is an extra bit appended to a byte which detects byte level transmission errors.
    e. DNP Parameters
        i. Connection Type = TCP/IP Client
        ii. UDP Listen Port = 0

6.4.4 SCADA Channel Group Configuration

6.4.4.1 A channel group ties channels and RTUs together to encapsulate the redundancy that exists for a communication path to the field. Currently only a single channel is assigned to a channel group, there is only one connection to a RTU. OpenFep Channel Groups are defined as follows:

    a. Name (used for log files and alarms
    b. Protocol
        i. DNP
            1. Master Addres = 10
            2. Connection Type = TCP/IP Client
            3. APDU Sixe in Blocks = 2
            4. Max Points Per APDU = 23
        ii. Series5
            1. Channel Periodic Scan Definition
                a. 7: ACCUM FREEZE

b. 29: SOE TIME SYNCH

iii. Telegyr

1. Channel Periodic Scan Definition = 10:ACCUMULATOR FREEZE

6.5. DATABASE CONFIGURATION

6.5.1. SCADA Station Configuration

6.5.1.1. The SCADA Station Name is the full name that will appear on the point displays for the points assigned to this station. It will also appear in the alarm message when alarms are generated for points on this station. It can also be used as a filter on the alarm display. Each SCADA point needs to be assigned to a valid station.

6.5.1.2. The Station Name is assigned to a SCADA Station record number by the SCADA DBA from the list of available blank Station Numbers.

6.5.1.3. Station Number is the station record number

6.5.1.4. Abbreviation (not used)

6.5.1.5. AOR Group assignment is used to set the viewing permission for the station. Assign each station to one of the following AOR Groups:

a. GCR (Gulf Coast Region) AOR Group – 1
a. NTX (North Texas Region) AOR Group – 3
b. CTX (Central Texas Region) AOR Group – 5
c. WTX (West Texas Region) AOR Group – 7

6.5.2. SCADA KEY Configuration

6.5.2.1. SCADA point key is an 8-character unique identifier assigned to each point in the SCADA database. It follows the TRP (Type-Remote-Point) format whereas:

a. 00^{T} 000^{R} 000^{P} i.e. 01025066

i. T = Point Type (the first two numbers from the left) is used to identify SCADA point type and functionality

1. 01 = Telemetered status
2. 02 = Calculated status
3. 03 = Telemetered analog
4. 04 = Calculated analog
5. 05 = Telemetered accumulator
6. 06 = Calculated accumulator
7. 09 = Setpoint (rarely used at TNMP)

ii. R = RTU Record (the next three numbers from the left) is used for the station number.

iii. P = Point number (the last three numbers from the left) is used to identify the point number within the station.

6.5.2.2. SCADA Point types indicate the type of SCADA point and functionality.

a. T_IND - Receives telemetered data from a source such as FEP or ICCP and does not issue controls.
b. T_I&C - Receives telemetered data from a source such as FEP or ICCP and can send controls.

c. T_CTRL - Only sends breaker controls to a source such as FEP or ICCP. It does not receive any telemetered data.
d. C_IND - Receives calculated data from TNP_Calcs program or Internal Calculation program. TNMP currently does not use this point type.
e. T_JOG - Sends outbound job control to a destination, such as FEP or ICCP. It is currently used at TNMP to raise and lower taps on Auto Transformers.
f. M_IND - Receives data manually through user input from OpenView. It will not set a quality tag.
g. T_ACCUM - Receives telemetered count value over a configurable period of time to determine power quantities that have flowed over a 5-minute period.
h. C_ACCUM - Receives a calculated count value (from OpenCalc or a customer Application) over a configurable period of time to determine power quantities that have flowed over a 5-minute period.

6.5.3. Generating Point Data Records

6.5.3.1. Point data records are generated from point definitions from each RTU in the database. The records are created in order, according to RTU record number, and comprise a complete list of all the points that OpenFEP scans. Each record is assigned a FEP key based on its point type, RTU number, RTU abbreviation and point number as well as configuration in the fep.rc file.

6.5.3.2. Internal record pointers are used to generate displays. These pointers are assigned during a fep_build.

6.5.3.3. Each point data record must be linked to a SCADA key if it is needed in the SCADA database. This link is established by the Link Method parameter in the fep.rc file.

6.5.4. FEP Key Linkage to SCADA Key

6.5.4.1. Link Method 2 is the default link method and is utilized by TNMP for linking point data records to SCADA points. This method uses the present data to maintain the current link. It uses the SCADA key entered in the SCADA Key column of the Point configuration display to generate a link.

6.5.4.2. FEP Key – Is a point data record generated when an RTU is added to the FEP database from the point definitions from each RTU in the database. The keys are created in order, according to RTU number, and comprise a list of all the points that OpenFEP scans. The FEP KEY to SCADA Point mapping criteria is provided by Communications on project specific point lists.

a. Each FEP KEY must be linked to a SCADA key (point type and record number) if it is to be scanned and is needed in the SCADA database.

6.5.4.3. FEP Type – Auto populated based on protocol type

6.5.5. AOR (Area of Responsibility) Configuration

6.5.5.1. AOR groups are used to configure a set of AORs that will be used to determine view and control permission of SCADA points and their associated alarms.

a. GCR – AOR group 1
b. NTX – AOR group 3
c. CTX – AOR group 5
d. WTX - AOR group 7

6.5.6. Alarming

6.5.6.1. Alarm Groups - Many events can occur for SCADA points. These events are combined into alarm groups. The Alarm process monitors all SCADA points that have an alarm group configured for these events. Alarm groups are used to configure alarming parameters for groups of similar points

a. Alarm Groups are defined by the following parameters:
   i. Group Number – The order of the alarm group
   ii. Group Name – The name displayed in the detail and configuration displays
   iii. Group Mode – On/Off. Alarms will not be generated for this alarm group if set to off
   iv. Max Unack – The maximum number of unacknowledged alarms allowed on a SCADA point in this alarm group.
      1. 0=no limit
   v. Priority – This value suppresses lower priority alarms that occur at the same time as higher priority alarms for a particular substation.
      1. If alarms in this alarm group are below priority of their substation, alarm suppression can occur.
      2. If the alarm group priority is equal or greater than the substation priority, alarm suppression will not occur.
   vi. Delete Acknowledged on RTN
      1. ON = pre-existing acknowledged alarms on a SCADA point in this alarm group will be deleted when a Return to Normal alarm is generated on that SCADA point
   vii. Ack Unacknowledged on RTN
      1. ON = pre-existing unacknowledged alarms on a SCADA point in this alarm group will be acknowledged with a Return To Normal alarm is generated on that SCAD point.
   viii. Event No. – The number of alarm events (not configurable)
   ix. Event Description – The description of the alarm event that will generate an alarm in the associated alarm class. Events are not configurable and should not be changed.
   x. Class No. – The number of the alarm class used when the associated event occurs
   xi. Class Name – The name of the alarm class used when the associated event occurs. Configured on the Alarm Class Definition display.
   xii. Class Message/Description – The message of the alarm class used in the alarm message when the associated event occurs.
      1. Right click on the field to open a pick-list of available alarm classes to enter here.
      2. Double-click to jump to the Alarm Class Definition display for the alarm class
   xiii. Class Severity – The severity of the alarm class used when the associated event occurs.

6.5.6.2. Alarm Classes – Alarm classes determine the behavior of the alarm

a. Alarm Classes are defined by the following parameters:
   i. Class No. – Order of Alarm Class

ii. Class Name – Name of Alarm Class
iii. Message – The text used for the Event Field on Alarm Displays
iv. Severity – Alarm severity (1 (lowest) to 8 (highest) or Event
v. Color – The color the alarm will be displayed
vi. Print Group – Logger print group if sent to logger printer (not used)
vii. Volume – UNIX Only (not used)
viii. Tone – Frequency of alarm sound
ix. Pattern – Pattern of alarm sound
x. Disable Alarm – If set to ON will not generate an alarm
xi. Archive to RDBMS – Alarms will be archived
xii. Post As – State of alarm when it is issued:
    1. ACKNOWLEDGED
    2. UNACKOWLEDGED
    3. DELETED
    4. LOG
xiii. Delete on Acknowledge – Alarms will be automatically deleted when acknowledged.
xiv. Ignore Alarm Inhibit – Will ignore Alarm Inhibit and Station Inhibit flags when set to ON
xv. Deadband – Delays status and analog alarming when set to ON. To ensure proper deadbanding on STATUS points you must configure both the Change of State and the Return to Normal alarm classes to have the same number of Deadband Scans.
    1. Deadband Value – Value in engineering units that must be exceeded by SCADA analog point before an alarm is issued.
    2. Deadband Use as % - When ON Deadband value is treated as a percentage of the limit value that the SCADA analog value must exceed before an alarm is generated.
    3. Deadband Scans -The number of scans that the SCADA point must be in an alarm condition before the alarm will be generated.
xvi. Process Execution – Will execute processes specified when set to ON
    1. Processes – List of processes to execute when an alarm is used from this alarm class.
xvii. Email – Alarms in this class will send emails to the addresses specified in list.
    1. Email Addresses – Email addresses to used when an alarm is issued.
xviii. Display Call-up – Specified file name and panel name will be called up in OpenView on every console when alarm is generated.
xix. Alarm Digits – Alarms with floating point value will use the number of decimal places configured to display value on alarm display
xx. Periodic noise – Unacknowledged alarms will periodically send an audible alert rather than sending a continuous audible alert.

6.5.7. Alarm group Configuration

6.5.7.1. TNMPs primary alarm groups are as follows:

a. Analog Groups (primary groups used by TNMP)
    i. Saturation – 60
    ii. Transmission TRF MVA – 61
    iii. Distribution TRF MVA – 62
    iv. Transmission Line MVA (MLSE) – 63
    v. Transmission Voltage – 64
    vi. Distribution Voltage – 65
    vii. Distribution TRF PF – 66
    viii. Frequency – 26
    ix. Transmission Line Amps Delta – 67
    x. Distribution Circuit Amps (bank breakers) – 68
    xi. Bus Net – 69
    xii. Tap Position – 70
    xiii. Tap Imbalance – 71
    xiv. Station AC Volts – 72
    xv. Station DC Volts – 73
b. Status Groups
    i. Distribution Status – Group 1
    ii. Transmission Status – Group 4
    iii. Generic Alarms - Group 7

6.5.8. State Name Configuration

6.5.8.1. State names are configured to represent the telemetered state of a device, such as OPEN and CLOSED, and are configurable on each point.

6.5.8.2. The State Name Index assigned to a point is based on state names provided in points list (primary ones used)

a. Open/closed – 201
b. Off /on – 202
c. Trip/close – 203
d. Tap/tap – 205
e. Alarm/reset – 206
f. Local/remote – 212
g. Enable/disable – 213
h. Alarm/normal – 220
i. High/normal – 221
j. Failed/normal – 223
k. Trip/reset – 224
l. Normal/bypass – 226
m. Reset/trip – 231

6.5.9. Scale Factors

6.5.9.1. Analog points, accumulators and set points all require scale factors to be configured to convert from raw count values to engineering values. Scale Factors are typically provided in the points list supplied by Communications. Calculations are dependent on Protocol type, CT ratios, PT ratios and Max Range of Transducer outputs

6.5.9.2. The scale factors group contains a list of all scale factors currently in use.

6.5.9.3. If the scale factor needed is not already configured in the Scale Factor Group, a new Scale Factor Group Number can be added.

a. Choose an unused Scale Factor Group Number. Open records are indicated by a blank in the name field and all zeros in the scale factor value field.
b. Enter the scale factor name i.e. 105 FS / 2000 cnts
c. Enter the new scale factor value
d. Enter the Offset

6.5.9.4. Once a new record is added it is immediately available for use.

6.5.10. TOA/MultiSpeak Configuration

6.5.10.1. MultiSpeak names are assigned by the SCADA DBA when a new distribution circuit is placed in service. Distribution circuit breaker statuses are sent to the Outage Management System. MultiSpeak utilizes a specific naming convention for linking SCADA points to MultiSpeak names.

6.5.10.2. MultiSpeak Status Point Naming Convention

a. A MultiSpeak Object name is composed of 45 characters combined to form a single text string (rr_ssss_d30)
   i. rr-is the two-character region abbreviation
      1. WT = West Texas
      2. GC = Gulf Coast
      3. CT = Central Texas
      4. NT = North Texas
   ii. ssss - is the 3 to 4-character station abbreviation
      1. see list
   iii. d30 = 1-30-character device name

6.5.10.3. MultiSpeak Analog Point Naming Convention

a. Analogs are not currently being configured in MultiSpeak.

6.5.10.4. MultiSpeak points are configured in OpenDMA on the Published Status Configuration display.

6.5.10.5. The following information is used to link a point in MultiSpeak

a. SCADA Key – Enter the SCADA key for the device to be configured
b. Published name – Enter the assigned MultiSpeak name
c. PointGroup = Status Points
d. Writable = No
e. State Calculator = No
f. SourceDB = SCADA

6.5.11. SCADA Point Configuration

6.5.11.1. SCADA Points are configured in batch using Data Explorer or individually using the SCADA Database Editor.

6.5.11.2. Points represent a single input value that is monitored or controlled by the SCADA system. Points are stored as a value and a timestamp when it was recorded. A series of time stamped values gives the history of that point. TNMP uses the following point types:

a. Status Point Configuration
   i. Telemetered Status Configuration
      1. Status Type
         a. T_IND
         b. T_I&C

        2. Point Name unique within same substation
        3. Point Key
        4. Station Key
            a. Each SCADA point needs to be assigned a valid station.
        5. State Name Index based on state names provided in points list
        6. Alarm Group configuration
        7. AOR Group configuration
        8. Configured Normal State
        9. ICCP Data – See ICCP section
        10. Archive Group configuration
        11. Currently do not archive status points
    ii. Calculated Status Point Configuration
        1. Status Type
            a. Pseudo points for non-telemetered switches
            b. M_IND
        2. Point Name unique within same substation
        3. Point Key
        4. State Name Index based on state names provided in points list
        5. Alarm Group configuration
        6. AOR Group configuration
        7. Archive Group configuration
        8. Currently do not archive status points
        9. Configured Normal State
        10. ICCP Data – See ICCP section
b. Analogs Point Configuration
    i. Telemetered Analog Configuration
        1. Point Type
            a. T_ANLG
        2. Point Name unique within same substation
        3. Point Key
        4. Raw Count Format
            a. Default
            b. Unsigned
    ii. Scale Factor as provided on points list
    iii. Alarm Group configuration
    iv. Archival Group configuration
    v. AOR Group configuration
    vi. ICCP Data – See ICCP section
    vii. Flat Line Time where applicable
    viii. Alarm limit Configuration based on type of analog measurement.
        1. Reasonability limit
        2. Limit 1
        3. Limit 2
        4. Limit 3

5. Limit 4

ix. Archive group Configuration
1. MW – 000001111
2. MV – 00001111
3. KV – 00001011
4. VOLTS – 00001010
5. AMPS – 00001111
6. TAP – 00001010
7. FREQ – 00001011
8. MVA – 00001111

c. Calculated Analogs Configuration
i. Point Type
1. C_ANLG
ii. Point name unique within same station
iii. Point Key
iv. Alarm Group configuration
v. Scale Factor as provided on points list
vi. Archival Group Configuration
vii. ICCP Data – See ICCP section
viii. Calculated MVA when telemetered value not available
ix. Calculated PF when telemetered value not available
x. Bus Net Mw & MVAR
xi. Alarm limit Configuration based on type of analog measurement.
xii. Reasonability limit
1. Limit 1
2. Limit 2
3. Limit 3
4. Limit 4
xiii. Archive group Configuration
1. MW – 000001111
2. MV – 00001111
3. KV – 00001011
4. VOLTS – 00001010
5. AMPS – 00001111
6. TAP – 00001010
7. FREQ – 00001011
8. MVA – 00001111

d. Jog/Pulse Point Configuration
i. Point Type
ii. T_JOG
iii. Point Name unique within same substation
iv. Point Key
v. Configured normal Sate
vi. State Name Index based on state names provided in points list
vii. Reset Normal Sate on Control = ON
viii. Analog Key for R/L Feedback = key for Tap Analog value
ix. Default Pulse Value = 1.1 or 1.0 for DNP RTUs.

x. Pulse Value Scale Factor Group = 25
xi. Pulse value Deviation for Failure = 75%
xii. Max Pulse Width = 0
xiii. High R/L Control Limit = +16.0
xiv. Low R/L Control Limit = -16.0
xv. Alarm Group configuration
xvi. AOR Group configuration =
xvii. ICCP Data – See ICCP section
xviii. Archive Group configuration
    1. Currently do not archive JOG points

e. Telemetered Accumulator Point Configuration
    i. Point Type
        1. T_ACCUM
    ii. Point Name unique within same substation
    iii. Point Key
    iv. Scale Factor as provided on points list
    v. Accumulator Rollover Value = 65535
    vi. Freeze / Reset state
    vii. Off
    viii. Analog Comparison Type
    ix. Net Integration
        1. Display Reference
        2. Display Field 1 = 24
        3. Display Index 1 = 1
        4. Display Field 2 = 24
        5. Display Index 2 = 2
    x. Archive Group Configuration

f. Control Point Configuration
    i. Mode – enables or disables the control.
    ii. It should be left off while parameters are being changed in the control
    iii. State – provides feedback from the system and is not user-enterable
        1. OFF – The control entry is off and controls will not be sent
        2. ENABLED – Mode is ON and the entry is valid; you can send controls using this key
        3. INVALID –Entry is invalid. Verify the parameters are valid based on the protocol.
    iv. SCADA Key – Indicates the origin of the control based on the points list provided by Communications and T_C&I point defined in SCADA database.
    v. Duplicate keys apply only to Open Only and Close Only control types providing the control type compliments the first.
    vi. SCADA Type – is set based on where FEP-Build found the SCADA Key
    vii. SCADA Name – appears after FEP-Build successfully links the control to SCADA
    viii. Control Type – sets the type of control being configured. Refer to the protocol for control type specifics

1. Open only-only open control is allowed
2. Close only-only close control is allowed
3. Open/close-both open and close control is allowed
4. Auto-fep_build will try to decide which control you are trying to configure based on the SCADA key
5. Raise Only-only raise control is allowed
6. Lower Only-only lower control is allowed
7. Raise/Lower-both raise and lower controls are allowed

ix. Reverse Control – Provides the ability to reverse the logic on the control received from SCADA before it is transmitted to the RTU. It is Rarely used
x. Control Format – Directly relates to the protocol. Refer to the protocol for format type specifics
xi. Priority – not used
xii. Select and Operate Retries – the number of times the OpenFEP process should retry the control on a communication failure. Select retries are only relevant for SBO (Select Before Operate) control
xiii. RTU –FEP record number of the RTU that contains the control point configured
xiv. Point Address – the address of the point you wish to control on the RTU (provided in Communication points list)
xv. Default Execute Tick – Protocol specific value proportional to the control duration
xvi. Execute Multiplier – Protocol specific value which, when combined with the execute tick, determines the duration of the control.

6.5.12. ICCP Configuration

6.5.12.1. Export Point Configuration - The ICCP database map defines a relationship between an ICCP point and SCADA. Each ICCP point requires a key for point values to be written to. The following are configuration parameters for Points sent to ERCOT as required by protocols.

a. Status Points
   i. Database = 10
   ii. Object = 4
   iii. Field = 20
   iv. REC/Key = SCADA KEY for the Status Point being sent to ERCOT
   v. IDX = not used
   vi. Scan Class = 9 (10 seconds)
   vii. Alternate Scan Class is 13 (10 seconds with offset)
   viii. Dataset = 1 (Points_For_ERCOT)
   ix. Point Name = Unique ICCP Name as required by ERCOT Protocols. See ICCP Build Process for details.
   x. Point Type = StateQTime
   xi. State Calc = 2_to_4
b. Analog Points
   i. Database = 10
   ii. Object = 5
   iii. Field = 20
   iv. REC/Key = SCADA KEY for the Analog Point being sent to ERCOT

v. IDX = not used
vi. Scan Class = 9 (10 seconds)
vii. Alternate Scan Class is 13 (10 seconds with offset)
viii. Dataset = 1 (Points_For_ERCOT)
ix. Point Name = Unique ICCP Name as required by ERCOT Protocols. See ICCP Build Process for details.
x. Point Type = RealQTime
xi. State Calc = None

6.5.12.2. Import Point Configuration - The following points are configuration parameters for points received from ERCOT for data from neighboring utilities.

a. Status Points
   i. Database = 10
   ii. Object = 4
   iii. Field = 20
   iv. REC/Key = SCADA KEY imported value will be written to
   v. Transfer Set = Transfer Set name configured for Neighboring Utility
      1. 1 = AEP_FROM_ERCOT
      2. 2 = TXU_FROM_ERCOT
      3. 3 = BEPC_FROM_ERCOT
      4. 4 = GPLT_FROM_ERCOT
      5. 5 = AMOCO_FROM_ERCOT
      6. 7 = CNP_FROM_ERCOT
      7. 8 = ONCOR_FROM_ERCOT
   vi. Point Name = Neighboring utilities unique ICCP Name (can be obtained either from the neighboring entity or from ERCOT MAGE/SGEM)
   vii. Point Type = Specified by neighboring utility
   viii. State Calc = Specified by neighboring utility

b. Analog Points
   i. Database = 10
   ii. Object = 5
   iii. Field = 20
   iv. REC/Key = SCADA KEY imported value will be written to
   v. Transfer set = Transfer Set configured for Neighboring Utility
      1. 1 = AEP_FROM_ERCOT
      2. 2 = TXU_FROM_ERCOT
      3. 3 = BEPC_FROM_ERCOT
      4. 4 = GPLT_FROM_ERCOT
      5. 5 = AMOCO_FROM_ERCOT
      6. 7 = CNP_FROM_ERCOT
      7. 8 = ONCOR_FROM_ERCOT
   vi. Point Name = = Neighboring utilities unique ICCP Name (can be obtained either from the neighboring entity or from ERCOT MAGE/SGEM)
   vii. Point Type = Specified by neighboring utility
   viii. State Calc = Specified by neighboring utility

7. DISPLAY BUILD

7.1. Display Types

7.1.1. Transmission Overview Displays

7.1.1.1. Transmission Overview Displays are simplified drawings depicting multiple substations connected by Transmission lines as they are connected on the TNMP Transmission Grid. The overviews may also contain Point of Interconnection substations with neighboring utilities.

7.1.1.2. The TNMP overview displays are contained in one OSI Design Studio display (.ODS) that contains 6 pages for each of TNMPs 6 regions. All_Overviews.ODS is the name of the overview display file.

7.1.1.3. Regional Overview Displays

a. West TX North 138kv
b. West TX Wink to Pecos Loop
c. West TX South
d. Lewisville
e. Central
f. Gulf Coast
g. Robertson County

7.1.2. Transmission and Distribution One-line Display

7.1.2.1. Transmission and Distribution one-line displays are used to view TNMP substation network connectivity. One-line displays are made up of static and dynamic objects representing breakers, transformers, capacitors, bus bars and conductors. The diagrams are usually arranged in order of decreasing voltage levels, with the highest voltage drawn at the top and the lowest voltage at the bottom.

7.1.2.2. A one-line is drawn for each substation and is stored in a regional ODS. To reduce crowding on the displays, a separate one-line display may be built for each voltage level in the substation.

7.1.3. Station Displays

7.1.3.1. The Station Summary lists all the stations in the system. You can view the state of each station and its current alarm status.

7.1.4. Tabular Summary Displays

7.1.4.1. OpenSCADA tabular displays are used to view SCADA point details. Real-time SCADA data is shown on tabular displays accessed from OpenView main menu. Tabular displays are system configured and are not typically modified.

7.1.5. Status Point Display

7.1.5.1. Status Point Displays enable you to view and configure a single Status Points. There are three status point displays

a. Status Summary - Provides a summary of the status points within the SCADA database
b. Status Detail - Provides details for individual status points. It is used to configure status point parameters.
c. Substation Status Display - Provides list of points for one substation at a time.

7.1.5.2. Analog Point Displays - Enables you to view and configure analog points. There are three analog point displays

a. Analog summary - Provides a summary of the analog pints within the SCADA database
b. Analog Detail - Provides details for individual analog points. It is used to configure analog point parameters.
c. Substation Analog Display - Provides list of analog points for one substation at a time.

7.1.5.3. Accumulator Point Displays - Enables you to view and configure accumulator points. There are three accumulator displays

a. Accumulator summary - Provides a summary of the accumulators within the SCADA database.
b. Accumulator Detail - Provides details for individual accumulator points. It is used to configure accumulator point parameters
c. Substation Accumulator Display - Provides a list of accumulator points for one substation at a time.

7.1.5.4. Setpoint Point Displays - Enables you to view and configure setpoints. There are three setpoint displays

d. Setpoint summary - Provides a summary of the setpoints within the SCADA database.
e. Setpoint Detail - Provides details for individual setpoints. It is used to configure setpoint point parameters
f. Substation Setpoint Display - Provides a list of setpoints for one substation at a time.

7.1.6. System Displays

7.1.6.1. Numerous system displays are available for viewing and configuring SCADA system information. The system configured OSI displays are not modified. For detailed information on these displays and all OSI displays you can reference OSI documentation. Various displays for TNMP specific information are also available and must be maintained by the SCADA DBA.

7.1.6.2. SCADA Displays

a. Station Summary
b. Tag Summary
c. Limit and Abnormal Summary Displays
d. SCADA Configuration Displays
e. Quality Summary
f. SCADA process Information Displays
g. Scale Factor Display

7.1.6.3. Alarm Displays

a. Alarm Summary Display
b. Alarm Configuration Displays

7.1.6.4. OpenFEP Displays

a. RTU Displays
b. Channel Displays
c. Control Configuration
d. Point Configuration

7.2. Display Libraries

7.2.1. Symbol Libraries

7.2.1.1. OSI provides a library of composite objects (symbols) to use to create one-line drawings. TNMP maintains customized Symbol Libraries for each voltage level. While the majority of the custom libraries contain object for only one specified voltage level, there may be exceptions. Be sure to check all libraries if you do not find the desired object in its respective voltage level

a. 345KV_TNP.LIB2
b. 138KV_TNP.LIB2
c. 69KV_TIP.LIB2
d. DIST_TNP.LIB2

7.2.2. Data Binding

7.2.2.1. Data Binding connects a library object (symbol) to a SCADA point. Once assigned the item will always represent that item. To bind an object, you must link the item to a database and field. SCADA Points are typically linked to the SCADA database, Status or Analog Field, State or Value and a Key.

7.2.3. Color Binding

7.2.3.1. Color Binding overrides the symbol's default color with the color of the link. When you color bind a symbol to a States Table the system does not look at the words in the states table; it only looks at the color of the words. Color binding is used for Breakers and analog values.

a. Blinking breakers
    i. STATE NAME 207 – BLINKING BREAKERS
b. TLQ Colors
    i. STATE NAME 53 – TLQs Colors

7.2.4. Dynamic Objects

7.2.4.1. The following symbols are typically dynamically linked to a SCADA key, are two state devices and are customized in TNMP libraries.

a. BKRS – breakers (OCB, GCB, VCB, ACB)
b. MOAS – Motor Operated Air Switch
c. MOCS – Motor Operated Circuit Switch
d. GOAS – Gang Operated Air Switch
e. DS – Single Blade Disconnect Switch
f. FUSED DS – Fused Disconnect Switch
g. CIRCUIT SW – Circuit Switcher without blades
h. SUPY SW – Supy Switches
i. SUPY RCLSR – Supy Reclosers
j. MANL RCLSR – Manual Recloser Status Switch
k. TAP – Tap indications
l. Buttons
m. BLOCK CLOSE – Cap Banks
n. HOT LINE TAG RECLOSER – Distribution Supy Recloser where Hot Line Tag Functionality is configured in the relays.

7.2.5. Static Objects

7.2.5.1. The following symbols are typically static symbols. They are NOT usually dynamically linked and are customized in TNMP libraries.

a. Cap Banks
b. Transformers
c. Loads
d. Regulators
e. Arrows
f. Metering Symbol
g. Generator Symbol
h. Ground symbol
i. Potential Transformer (PT)
j. Reactor
k. STATCOM-Static Var Compensator
l. Other Static Elements
   i. Analog Unit Names
   ii. Station Names
   iii. Device Names
   iv. Device Numbers
   v. Line names
   vi. Dividers
   vii. Point of Interconnect identifiers
   viii. Dead-end/Endcaps
   ix. ERCOT nomenclature
   x. Distribution Load Shed Priority
   xi. Notes

7.3. Displaying Dynamic Points

7.3.1. Displaying Status and Control Points

7.3.1.1. Preferences:

a. Status point symbols should be displayed centered on the static line.
b. Status point symbols should be aligned and brought "to the front" of the static line on which it is placed.
c. Status and Control points should always be configured with TLQ turned on.
d. Device names identifying the source of the point (i.e. BKR name) can be placed above, below, to the left or right of the device with the TLQ placed above, below, or to the right of the device.
e. Device names and TLQ placement largely depends on the configuration of the bus and the amount of space available on the display.
f. Device names should not obstruct the view of the device itself.
g. TLQs should not obstruct the view of the device name or the device itself.
h. Status point symbols should be evenly spaced in relation to other devices on the bus.

7.3.2. Displaying Analog Values

7.3.2.1. Preferences:

a. Analog values should be displayed aligned and justified.

b. Analog values should always be configured with TLQ turned on.
c. The units label (static) should be placed to the left of the analog value, with the TLQ placed to the right of the analog value.
d. TLQ should not obstruct the view of the analog value itself or the analog unit's label.
e. In the case of multiple phase readings for a single device, each phase should be clearly identified.
f. MW & MVAR should have dynamic arrows defined indicating directional flow.
g. Tap indication is placed to the left of the TAP label and TAP label should be dynamically linked to the TAP raise/lower JOG point if available.

7.4. Snap Size

7.4.1.1. A snap grid is a grid over your WCS is used as a guide for simplifying your drawing tasks. The size of the squares (and the amount of space between the gridlines) is dictated by the snap size. By default, the grid is turned off and does not display.

7.4.1.2. Overview displays are generally created at snap size = 3

7.4.1.3. One-line displays are generally created at a snap size = 10

7.4.1.4. Because of the increasing amount of data being displayed, snap size may be adjusted as needed to accommodate display crowding and object alignment. Legibility should be considered when changing the snap size.

7.5. Zoom Level

7.5.1.1. Zooming allows you to see more detail (zoom in) in an ODS display or a more complete birds' eye view of an entire display (zoom out). Each time you click Zoom In you see more detail and the objects in your view get larger. Each time you click Zoom Out you see less detail and the object in your view get smaller.

7.5.1.2. TNMP displays are generally created at a Zoom Factor = 10

7.5.1.3. Because of the increasing amount of data being displayed, the Zoom Factor may be reduced to increase the amount of available space on the display. Legibility should be considered when changing the zoom factor.

7.6. Panning

7.6.1. Panning allows you to move around the display using the horizontal and vertical scroll bars. Panning is done in percent increments.

7.6.2. TNMP display are generally created at a Pan factor = 10

7.6.3. Pan factor can be adjusted when editing a display to align display within viewing area.

7.7. Layers

7.7.1. Custom layers are currently not configured for TNMP displays.

7.8. Declutter

7.8.1. Custom decluttering is currently not configured for TNMP displays.

7.9. Overlays

7.9.1. Custom overlays are currently not configured for TNMP displays.

7.10. Colors

7.10.1. Lines & Buses

a. 12kv, 22kv and 25kv – bright green

b. 69kv – brown orange
c. 138kv – cyan
d. 345kv – Deep Navy blue

7.10.2. Breakers

7.10.2.1. 12kv, 22kv and 25kv
a. Green filled= closed state
b. Red hollow = open state

7.10.2.2. 69kv
a. Brown Orange filled= closed state
b. Red hollow = open state

7.10.2.3. 138kv
a. Cyan filled= closed state
b. Red hollow = open state

7.10.2.4. 345kv
a. Royal Blue filled= closed state
b. Red hollow = open state

7.11. Tags, Limits and Quality Codes

7.11.1. Tag Behavior

7.11.1.1. Tags control the behavior of individual points in the SCADA database. All tags are configurable except for the Point Lock Tag, which is set automatically by the system to indicate that another user is currently modifying the point.

7.11.1.2. Once a tag has been set, a single character representing the tag is displayed next to the point's status or value. If more than one tag type is set on a point, only the character that represents the tag type of highest priority is displayed. If multiple tags exist for a point, the highest priority tag is displayed to indicate this.

7.11.1.3. Tags can be active or inactive. An active tag will control the behavior of the point. When a tag is inactivated, it does not control any behavior on the point, but it preserves the tag information. This is helpful and frequently used during point-to-point checkouts when wanting to temporarily suspend the tag behavior without losing the tag's information. An inactive tag will be displayed as a lowercase letter. For example, the Control Inhibit tag's symbol is an uppercase "C". If this tag were inactivated a lowercase "c" would be displayed.

7.11.2. Tag Types

7.11.2.1. There are eight standard types of tags and they are displayed in the color Cyan.
a. Close Inhibit =!
   i. Prevents close commands from being issued
b. Control Inhibit = C
   i. Prevents any controls from being issued
c. Information = F
   i. Adds additional information about a device in the field
d. Hold = H
   i. Prevents Open commands from being issued
e. Alarm Inhibit = A
   i. Prevents alarms on a device
f. Scan Inhibit = S

i. Prevents updates to the value of a device from the field sources

g. Point Locked for Editing = :
   i. Prevents multiple users from modifying or controlling the same device at the same time
h. Alternate Data Source = @
   i. Replaces the value of one device with the value of another field device
   ii. The ADS tag is configured on the Point Detail screen where the user enters the alternate point's key into the point.
   iii. After the ADS tag is applied the alternate point's data is used as the point's value and the point's original data is stored in another field in the point.
   iv. Each of the values along with its key is in the Point Dialog box. The asterisk next to one of the values indicates which value is currently being used.
i. V Tag active(point scan inhibited not checked out in SCADA = ⊗
   i. V Tag inactive (point checkout in progress) = ✓
   ii. An active "V" tag is applied to all new SCADA points until they are successfully verified or checked out with field personnel. A "V" tag takes the point out of scan and signifies to System Operator that the point is not in service and has yet to be checked out.
j. Hot Line Tag = ▽
   i. Specialty tag linked to Distribution Hot Line Tag Control points that will disable reclosing when applied.

7.11.3. Limits

7.11.3.1. Limits alert the operator to abnormal conditions, such as an analog value that exceeds a set limit or a status point in an abnormal state that will require attention.

7.11.3.2. Four separate limit violations flags are configured for each operational limit for analog points

7.11.3.3. Abnormal Limit flag for are configured for status points when they are not in their normal state

7.11.3.4. Override Limit flag are configured for analogs which indicate when an analog point's limits or a status point's normal state has been overridden.

7.11.3.5. Limits are displayed in purple.

7.11.4. Quality

7.11.4.1. Quality flags identify bad data or manually entered information

a. Questionable (Q) Set on a point when the accuracy of the data is in doubt
b. Substitutions - Set when an accumulator's value is replaced through substitution (not used)
c. Non-Update (#) Set when data is not being updated from its source (usually failed telemetry from an RTU)
d. Reasonability (R) Set when an analog value exceeds its configured Reasonability range
e. Manual Entry (M) Set when performing manual entry on a point
f. Quality flags are displayed in yellow.

7.11.5. TLQ

7.11.5.1. The TLQ is a three-character field that displays next to the points status or value. It shows the highest priority Tag, Limit and Quality respectively, which currently exists on the point

7.11.5.2. TLQ should be configured for all dynamically linked devices.

7.11.5.3. TLQ Placement is largely dependent on the available space around the device that is being linked. However, OSI allows for placement to the immediate right and left, immediately above and below, upper right and upper left, and lower right and lower left of the object.

7.11.5.4. TLQs preferred placement is to the right or below the linked item unless there is another object obstructing placement.

7.12. ID Block

7.12.1. A station ID block exists for each station display. It contains the following:

a. TNMP Station Name dynamically linked to the overview for that station's region.
b. ERCOT Station Name
c. Voltage
d. Station Number
e. RTU Number
f. Analog Tabular Button
g. Status Tabular Button
h. Station Telephone Number or extension if known or available
i. Bus Net MW & MVARs when available

7.13. Pokes and Display Jumps

7.13.1. Display jumps are typically defined on station displays to allow the user to jump from one station to the next adjoining station or from one voltage level at that station to another voltage level at the same station.

7.13.2. Display jumps are not visible to the user, however yellow text on a line name or voltage level will indicate a display jump is configured.

7.14. Customized Notes

7.14.1. Notes have been defined in the NOTES library and are used by System Operators to indicate various system conditions.

a. Notes
b. Danger Tag
c. Clearance Tag
d. Hot Line Order Tag
e. Do Not Cycle

7.15. Display Fonts

7.15.1. Displays should be drawn with the following:

a. Font Type = Lucinda Console
b. Font Size = 16
c. White text denotes TNMP owned equipment
d. Magenta text denotes OTHER COMPANY owned equipment
e. Yellow text is reserved for special notations and to indicate display jumps

f. N.O. notation in yellow text denotes a “Normally Open” device
g. LINE RECLOSING in yellow text denotes a Line Recloser
h. Cornflower Blue text in italics and bold denotes ERCOT NOMENCLATURE
i. Notes in red text are used for special operating instructions

7.16. Placement, Spacing and Justification

7.16.1. Placement, Spacing and Justification is largely dependent on the amount of space that is available on the display.

7.16.2. Labels should be aligned with and justified to existing and surrounding object labels. If a change is made to an existing label, consider modifying the placement of all other labels on the display to keep things uniform and consistent on the entire display.

7.16.3. Care should be taken to keep displays as uncluttered and as visually organized as possible while maintaining legibility.

7.16.4. All static Devices numbers and Dynamic Devices should be legible, selectable and unobstructed by tags or other objects.

7.16.5. Device numbers preferred placement is to the left of or above each device unless there is another object obstructing placement.

7.16.6. Analogs should be placed as close to the source device (source device will be indicated in the point description) as practicable given the amount of space available for placement

7.16.7. Many legacy one-line displays contain both transmission and distribution voltage levels. On displays where excessive cluttering becomes an issue, consider dividing up the existing display into separate transmission and distribution displays if possible.

7.17. Load Shed Priority Designations

7.17.1. In support of Regional TNMP Emergency Operations Plan (EOP) the Load Restoration/Shed Circuit Priorities are identified on affected distribution displays.

7.17.1.1. Priorities are identified as either High, Medium or Low priority with the following:

a. “HIGH”
   i. Font Type = Lucinda Console
   ii. Font Size = 16
   iii. Font Format = Normal
   iv. Font Color = Muted maroon red
b. “MEDIUM”
   i. Font Type = Lucinda Console
   ii. Font Size = 16
   iii. Font Format = Normal
   iv. Font Color = Muted grey blue
c. “LOW”
   i. Font Type = Lucinda Console
   ii. Font Size = 16
   iii. Font Format = Normal
   iv. Font Color = Muted light yellow

7.18. ERCOT Device Labels

7.18.1. Pursuant to COM-00204 Transmission Interface Elements and Transmission Interface Facilities must be specified with a common nomenclature when issuing an oral or written Operating instruction. ERCOT devices are labelled on the displays with the common nomenclature and are clearly identified for those elements and facilities associated with Tie-lines or adjacent entities.

7.18.1.1. ERCOT Device Labels should be displayed on Transmission Displays with the following:

a. Font Type = Lucinda Console
b. Font Size = 14
c. Font Format = Bold and Italics
d. Font Color = Cornflower Blue

8. ICCP EXCHANGE WITH ERCOT

8.1. Inter-Control Center Communication Protocol (ICCP)

8.1.1. ICCP is used to transfer Real-Time telemetry data from TNMP to ERCOT. ERCOT has implemented a TCP/IP based Wide Area Network (WAN) that supports the ICCP transfer of data between ERCOT and all Market Participants. Data transmission using the ICCP link must be formatted and coordinated according to ERCOT NODAL ICCP Communication Handbook to effectively manage system and market requirements.

8.2. ICCP Data Transfer

8.2.1. All ICCP data transferred to ERCOT shall satisfy the requirements of the ERCOT Nodal Protocols and Telemetry Standards

8.2.2. TNMP shall provide telemetry to ERCOT on all network data used to switch any Transmission Element or load modeled by ERCOT.

a. Breaker and line switch status of all ERCOT Transmission Grid devices
b. Line flow MW and MVAR
c. Breaker, switches connected to all Resources
d. Transmission Facility Voltages
e. Transformer MW, MVAR and TA.
f. Network transmission data (model and constraints) from TDSP

8.2.3. TNMP is not required to install telemetry on individual breakers and switches, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the switching operations and personnel.

8.2.4. TNMP shall update the status of any breaker or switch through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

8.3. State Estimator Standards

8.3.1. The ERCOT State Estimator Standards address the State Estimator's ability to detect, correct, or otherwise accommodate communication system failures, failed data points, stale data condition codes and missing or inaccurate measurements to the extent these capabilities contribute to State Estimator performance or as needed to meet reliability.

8.3.2. Accurate and redundant telemetry and an accurate transmission power system model are required by State Estimator in order to produce an optimal estimation of the transmission power system state

8.3.3. TNMP shall provide telemetered measurements on modeled Transmission Elements to ensure State Estimator observability of any monitored voltage and power flow between associated transmission breakers to the extent such can be shown to be needed in achieving the State Estimator Standards. The following may be considered:

a. The number of Transmission Elements connected to a transmission Electrical Bus
b. The peak demand of the Load connected to a transmission Electrical Bus.
c. The total of Resource capacity connected to a transmission Electrical Bus
d. The nominal transmission voltage of an Electrical bus
e. The number of Electrical Buses with injections or withdrawals along a circuit between currently monitored transmission voltage Electrical Bus
f. Connection of Loads along a continuous, non-branching circuit that may be combined for modeling purposes

g. The quantity of Load at an Electrical Bus that may have its connection to the transmission system automatically transferred to an Electrical Bus other than the one to which it is normally connected (rollover operation);
h. Electrical proximity to more than one Resource Node;
i. Degree or quality of continued observability following the loss of telemetry measurements resulting from a common mode failure of telemetry-related equipment (i.e., an N-1 telemetry condition); and
j. Other parameters or circumstances, as appropriate

8.4. ICCP Data Exchange Parameters

8.4.1. ICCP Data exchange parameters are defined in detail in the ERCOT Nodal Protocols, Telemetry Standards and ERCOT Nodal ICCP Communication Handbook.

8.4.2. ICCP Naming Convention defines the ICCP name as a unique object that is composed of six fields combined to form one 31-character text string (i.e. cccctttssssssssvvvveeeeeeeeuuuu) For example: TNMPCB_HEIGHTTN1380OCB13802ST__

8.4.2.1. cccc is the 1-4 character company name

8.4.2.2. ttt is the 1-3 character equipment type descriptor

a. Buss – BS
b. Transformer – XF
c. Line – LN
d. Reactor – SH
e. Breaker – CB
f. Switch (Telemetered or non-Telemetered) – SW
g. Load – LD
h. Capacitor - SH

8.4.2.3. ssssssss is the 1 to 8 character station name

8.4.2.4. vvvv is the 4-digit voltage level

a. The last digit represents the right of an implied decimal point (i.e. 138KV is entered 1380 and 13.8 is entered 0138)

8.4.2.5. eeeeeeee is the 1 to 8 character equipment name

8.4.2.6. uuuu is the 1 to 4 character units specification of the measured value

8.4.2.7. If the number of characters in a field is less than the specified maximum field length an underscore character (“_”) is used to separate the string from the next field of the object name.

8.4.2.8. An ICCP Data Type is assigned to the object. TNMP uses Time Stamps.

a. Real Q Time – Analogs with time stamp
b. Real Q – Analogs without time stamp
c. State Q Time – Status with time stamp
d. State Q – Status without time stamp

8.4.2.9. Data is transmitted to ERCOT on a 10 second frequency

8.5. Configuring ICCP in SCADA

8.5.1. Before required telemetry data can be exchanged with ERCOT it must be configured in the ICCP Database.

8.5.2. ICCP Names configured in SCADA must match ICCP Names configured in ERCOT Model Data

8.5.2.1. ICCP names are created according to the ICCP Naming Convention as assigned in the NRF- ERCOT ICCP NAME field and validated for accuracy during the modeling process in MAGE/SGEM

a. Point names configured in the master must exactly match the ICCP point name configured in the ERCOT Operations Model for successful data transmission. Mismatched point names will indicate “Suspect” in ERCOT EMS
b. ICCP Data Type in SCADA must exactly match ERCOT measurement quality configuration for successful data transmission. Mismatched Data Types will indicate “Suspect” in ERCOT EMS.

8.6. ICCP Reliability and Telemetry Standards

8.6.1. Guidelines for reliable data and telemetry standards are outlined in the ERCOT Nodal Protocols, Telemetry Standards and ERCOT Nodal ICCP Communications Handbook. TNMP is responsible for providing to ERCOT in accordance to these standards, continuous and reliable telemetry through ICCP linkage defined in the NOMCR and ICCP build process.

8.6.2. Initial Verification

8.6.2.1. After ICCP Configuration in SCADA is completed, telemetry point is verified as updating to ERCOT

8.6.2.2. Last Committed to Remote Destination Time is verified.

8.6.3. NRF is updated by recording the validation date in the DATE ICCP VERIFIED UPDATING field.

8.6.3.1. During Approval to Energize process ICCP is verified by ERCOT before field energization approval is granted.

8.6.4. ICCP Telemetry Performance Criteria

8.6.4.1. Real-time status and analog telemetry measurements shall be continually sent to ERCOT (every 10 seconds) for current operating data for all points being monitored.

8.6.4.2. Ninety-two (92%) percent of all telemetry provided to ERCOT must achieve a quarterly availability of eighty (80%) percent.

8.6.4.3. Exceptions to the general telemetry performance criterion shall be made for data points not significant in the solution of the State Estimator or required for the reliable operation on the ERCOT Transmission System.

a. Substations with more than two transmission lines and less than 10MW of load
b. Connection of loads along a continuous, non-branching circuit that may be combined for telemetry purposes
c. Substations connected radially to the bulk transmission system
d. Under ERCOT declared emergencies when the metrics has been suspended until normal operations have resumed.

8.6.4.4. ICCP associations shall achieve a monthly availability of ninety-eight (98%) percent, excluding approved planned outages.

a. Availability will be measured based on end-to-end connectivity of the communications path and the passing of configured data at the scheduled periodicity.

8.6.5. Disruptions in ICCP connectivity to ERCOT will result in SCADA alarm notifications as defined in the TNP Alarming Standard or by Notification from ERCOT Operations. Upon notification of loss of ICCP System Operators will immediately notify SOC System Support so ICCP connectivity can be investigated.

8.6.5.1. During normal business hours SOC TNMP Operations will notify the SCADA DBA of all incoming ICCP alarms. If the SCADA DBA is unavailable notification will be made to SOC Manager, IT Operations or an available SOC System Support staff.

8.6.5.2. After normal business hours TNMP Operations shall notify SOC System Support personnel on-call.

a. SOC Support will investigate and verify ICCP WAN connectivity, taking corrective action where necessary.
b. SOC Support will investigate and verify all Data Sets are updating taking corrective action where necessary.
c. SOC Support will investigate and verify individual ICCP Point connectivity taking corrective action where necessary.

8.6.5.3. TNMP Operations shall notify ERCOT as soon as practicable when telemetry will not be available or is unreliable for operation purposes.

8.6.5.4. TNMP Operations shall notify ERCOT as soon as practicable when telemetry is returned to normal state.

8.6.5.5. TNMP shall use fully redundant data communications between the control center system and ERCOT systems such that any single element of the communication system can fail and;

8.6.5.6. For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s)

8.7. ICCP Calibration and Testing

8.7.1. TNMP is responsible, as owner of telemetry equipment, to ensure that calibration, testing and other routine maintenance of equipment is performed consistently with the provisions of the Protocols, Telemetry Standards, and good utility practice.

8.7.2. TNMP shall have a plan on file with ERCOT to assure accurate telemetry of data.

8.7.3. If TNMP repeatedly fails to meet telemetry standards, ERCOT may require a revision of this plan.

9. SCADA CHECKOUT PROCESS

9.1. Checkout

9.1.1. SCADA Point-to-Point Checkout

9.1.1.1. Point to Point checkout is necessary to ensure facilities and equipment with SCADA monitoring are constructed as designed, fully tested and function properly with proper documentation prior to energization and that required information is being sent via ICCP to ERCOT. Point to point checkout activities may be used to support documentation requirements for ERCOT and NERC compliance.

9.1.1.2. A point to point checkout should be a well-planned, documented and managed engineering approach that verifies what was specified on the point list was installed in the field, that it functions properly and that it is successfully turned over to the System Operators for monitoring and control.

9.1.2. Roles and Responsibilities

9.1.2.1. <u>Project Engineer</u>

a. Manages the construction project.
b. Manages preparation of design document for major projects, communicates the proposed design and obtains approval from all applicable parties.
c. Ensures work related to project is coordinated between all stakeholders for timely energization of station and/or field devices.

9.1.2.2. <u>Protection Engineer/Relay Technician</u>

a. Manages Facility Design Changes and provides instrumentation and control system design and programming. Issues relaying one-line diagrams for the development of SCADA display one-lines, telemetry I/O point lists and scale factors.
b. Prepares initial telemetry I/O point list documentation for all new and modified data points.
c. Coordinates with the Communications Specialist to prepare the final I/O point list documentation for functional checkout.
d. Participates in the field SCADA functional checkout process.

9.1.2.3. Communications Specialist

a. Manages SCADA RTUs and HMI Slave Port configurations for ASOC data exchange.
b. Manages and maintains HMI and RTU telemetry I/O point lists.
c. Provides and provisions the communication network interface for substation SCADA remote terminal units (RTUs) and Human Machine Interface (HMI) telemetry systems.
d. Provides inputs for proposed SCADA system HMI changes.
e. Prepares and maintains the functional checkout point list based on inputs from the Protection Engineer to ensure proper test equipment and communication links are available.
f. Ensures the accuracy of all HMI and RTU telemetry I/O information given and checks for missing information from field devices.
g. Participates in the System Operations SCADA functional checkout process.

9.1.2.4. SCADA Database Administrator

a. Provides SCADA system design and programming including display and database development or revisions.
b. Participates in the System Operations SCADA functional checkout process with the point to point testing and documents the results for compliance.
c. Notifies/updates System Operators upon completion of System Operations SCADA functional checkout process and identifies active and/or inactive display points in the SCADA System.

9.1.3. Check Out Schedule and Coordination

9.1.3.1. Construction Schedule Monitoring

a. Communication and monitoring of the project construction schedule are essential to stay abreast of projected project completion and energization schedule.
b. The checkout schedule is directly dependent on the project construction schedule.
c. The SCADA DBA will actively monitor the project construction schedule by attending regular contractor hosted project meetings. If unable to attend the meeting, weekly meeting minutes are reviewed for changes affecting checkout and energization.

9.1.3.2. SCADA Checkout Scheduling

a. SCADA Checkout times are reserved by submitting a meeting request to the SCADA DBA with a Location Room of ASOC SCADA Checkouts for the requested date and time.
    xiii. The SCADA DBA will review the date and time and either approve, reject or propose an alternate time for the requested checkout.
    xiv. In the unlikely event that the SCADA DBA and/or the SOC Coordinator will be unavailable for scheduled checkout,

alternate checkout dates may be proposed to Engineering for consideration.

b. If an alternate date cannot be agreed upon by all party's notification should be made to Director of TNP Regional Engineering so that an alternate System Support employee can be scheduled to perform checkout in the SCADA DBA's absence.
c. If an alternate System Support employee cannot be scheduled to perform the checkout in the SCADA DBA's absence the Director of TNP Regional Engineering will determine the appropriate course of action for accommodating the checkout schedule.
d. Checkout must occur in advance of energization.

9.1.4. SCADA Checkout Procedure

9.1.4.1. Operator Notification & Approval to Begin Testing

a. The SCADA DBA will check with the System Operator on duty and request permission to begin testing.
b. The SCADA DBA will verify with the System Operator on duty if appropriate clearances and/or cycling orders have been granted to safely perform SCADA checkout.

9.1.4.1.1 Safety Check

i. Safety is a critical function of all checkouts. In most instances check out is performed on new equipment on a dead bus. However there are instances where checkout is performed on existing equipment that is already in service to re-verify controls and indication points that may have been reprogrammed. SCADA DBA will verify with field crew the status of the bus being tested.
ii. Has Field Personnel Checked in with System Operator
   1. Verify that field personnel have notified the on-duty System Operator of their intent to test new equipment. If they have not spoken to the System Operator they should do so before checkout begins.
iii. Is Everyone in the Clear?
   1. This safety check is performed to ensure that, in the unlikely event checkout does not go as planned, field personnel working near or on the equipment being tested are not put in harm's way.
   2. Verify with Technician working in the Substation that all field personnel are "clear" of the device being checked out.
   3. If field personnel are not "clear" of the device being checked, testing should cease until such time as testing can resume safely.
iv. All Existing Controls are in the Local Position
   1. When testing field switching devices with remote SCADA control capability in a station where existing control points are already in service, all existing controls

should be placed in the "local" position by field personnel before testing begins. This step is to prevent erroneous remote-control trip or close commands from being sent from the master to the existing devices where there is potential to interrupt service.

2. If testing is being performed in a new station not yet in service, this step can be skipped.

9.1.4.1.2 Checkout Clean-Up

i. Upon completion of all checkouts care should be taken to ensure that SCADA conditions have been restored to normal.
    a. Verify that all Active Alarms associated with checkout have been cleared from the Active Alarm summary. If you are unsure about which alarms were the result of checkout, consult with the System Operator on duty before clearing the alarm.

ii. Verify that polarity is correct on all analogs subject to test and that the directional arrows match the sign of the analog.
    a. If polarity is incorrect and an analog value is not indicating the correct sign, report this anomaly to field personnel immediately and seek resolution.
    b. If analogs cannot be verified until the station is energized, advise the System Operator and include these points in the Post SCADA Checkout Report (PSCOR)report. Analogs verification will have to be performed when energized.

iii. Verify that all "V" tags have been removed or made active on point that were successfully tested.
    a. If a point fails the appropriate test, the point should remain out of scan and the "V" tag should not be removed. Note this failed test in the Post SCADA Checkout Report (PSCOR).

iv. Have all Normal States Been Verified?
    a. Upon completion of the test, a thorough review all points in the station should be completed with Field Personnel. Any points that are still in alarm or that still have "V" tags applied should be acknowledged by field personnel as being either valid alarms or new points that are pending field verification.
    b. All valid or invalid alarms should be noted in the in the Post SCADA Checkout Report (PSCOR) and reported to the System Operator. Appropriate steps should be taken to clear erroneous alarms at the end of checkout.

v. Have All Breakers Switched to Local Been Returned to Supervisory position?
   a. Any points that have been switched to local to prevent erroneous trips as instructed in the Safety Check Section of this document, should be returned to the remote position by field personnel upon completion of checkout and before field personnel leave the station.
   b. If this step has not or cannot be completed, the System Operator on duty should be immediately notified. A device left in the Local position will prevent System Operators from being able to control the device in the event of an emergency.

9.1.4.2. Post SCADA Checkout Report (PSCOR) to System Operators

a. As defined in Section 9.2.1 of this document, upon completion of all checkouts performed a follow-up Post SCADA Checkout Report (PSCOR) is sent to the System Operators, Communications and Engineering summarizing the checkout.
a. Any outstanding issues on points that failed testing should be noted as well as Coincidental Loss of Monitoring and/or Control, Action Items and Follow up tasks. Included should also be a list of point that were not verified or checked out and the reason they were not tested.

9.1.5. Checkout Instructions

9.1.5.1. <u>Control Point Switching Device Checkout</u>

a. Before issuing a control command to any controllable switching device, the SCADA DBA shall first confirm with field personnel that the initial indicated and actual state of the device agree as either “Tripped” or “Closed”. Breakers points can be in the normal or abnormal state when testing begins, although the normal state is preferred.
a. Controls should be issued and verified from the one-line display.
b. Applicable V tag that have been applied must be in the inactive state before testing can occur.
c. The SCADA DBA shall request that the Controllable Switching Device be placed in the “LOCAL” position. Control Trip and Close shall be issued to the device from the one-line display while in the “LOCAL” position. The control command should not execute and a “Control Fail” alarm should be received in SCADA.
d. The SCADA DBA shall request that the Controllable Switching Device be placed in the “REMOTE” position. Control Trip and Close shall be issued to the device from the one-line display while in the “Remote” position. The control command should successfully execute, and a change of state alarm should be received in SCADA.
e. If the control tested successfully the V tag can be removed and the point left if scan.
f. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the points list with as much detail as is available.
g. A control point that fails testing should remain out of scan with the V tag active.

9.1.5.2. <u>Recloser Control Checkout</u>

a. Before issuing a control command to a reclosing device, the SCADA DBA shall first confirm with field personnel that the initial indicated and actual state of the device agree as either “On” or “Off”. Recloser points can be in the normal or abnormal state when testing begins, although the normal state is preferred.

b. Controls should be issued and verified from the one-line display.
c. Applicable V tag that have been applied must be in the inactive state before testing can occur.
d. If the control tested successfully the V tag can be removed and the point left if scan.
e. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the points list with as much detail as is available.
f. A control point that fails testing should remain out of scan with the V tag active.

9.1.5.3. <u>Jog Point LTC Tap Controller Checkout</u>

a. Existing Transformer TAP Controls
    i. Before testing new or existing LTC Tap Control (raise/lower) points on a transformer that is currently in service the following precautions must be taken before testing can commence:
        1. If possible, have the Transmission System Operator monitor the test with field personnel so that corrective action can be taken in the event of a failed test or unforeseen voltage event.
        2. If Transmission System Operator is unable to monitor the test, request permission to operate (raise/lower) the taps on the transformer that is in service and the request number of steps in the raise and lower directions that can be safely tested without adversely affecting voltage.
        3. Verify with the Transmission System Operator the transformer’s current tap position and the potential impacts that moving the taps will have on voltage.
        4. Once approval for testing has been granted with or without System Operator monitoring, testing may proceed.
    ii. Before testing an LTC Tap Control point, the SCADA DBA shall first confirm with field personnel that the initial indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
    iii. Controls should be issued and verified on the one-line display.
    iv. The applied V tag must be in the inactive state before testing can occur.
    v. The SCADA DBA shall request the LTC Tap Controller be raised in the field, one step at a time, to the highest step agreed upon by Transmission System Operator, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
    vi. The SCADA DBA shall request the LTC Tap Controller be lowered in the field, one step at a time, to the lowest step agreed upon by Transmission System Operator, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.

vii. The SCADA DBA shall send “Raise” commands to the LTC Tap Controller, one step at a time, until reaching the highest step agreed upon by Transmission System Operator, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
viii. The SCADA DBA shall send “Lower” commands to the LTC Tap Controller, one step at a time, until reaching the highest step of agreed upon by Transmission System Operator, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
ix. If the control tested successfully the V tag can be removed and the point left if scan.
x. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the point list with as much detail as is available. The Transmission System Operator should be notified immediately.
xi. A jog control point that fails testing should remain out of scan with the V tag active.

b. New Transformer TAP Controls
   i. Before testing an LTC Tap Control point, the SCADA DBA shall first confirm with field personnel that the initial indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
   ii. Controls should be issued and verified on the one-line display.
   iii. The applied V tag must be in the inactive state before testing can occur.
   iv. The SCADA DBA shall request the LTC Tap Controller be raised in the field, one step at a time, to the highest step of +16, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
   v. The SCADA DBA shall request the LTC Tap Controller be lowered in the field, one step at a time, to the lowest step of -16, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
   vi. The SCADA DBA shall send “Raise” commands to the LTC Tap Controller, one step at a time, until reaching the highest step of +16, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.
   vii. The SCADA DBA shall send “Lower” commands to the LTC Tap Controller, one step at a time, until reaching the highest step of +16, confirming with each step that the indicated position of the LTC Tap Controller and the actual state of the LTC Tap Controller agree.

viii. If the control tested successfully the V tag can be removed and the point left if scan.
ix. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the point list with as much detail as is available
x. A jog control point that fails testing should remain out of scan with the V tag active.

9.1.5.4. <u>Status Point Checkout</u>

a. Before testing a status point, the SCADA DBA shall first confirm with field personnel that the initial indicated and actual state of the device agree as either “Normal” or “Abnormal”. Status points should be in the “Normal” state when testing begins.
b. Status points can be verified from either the Substation Status Display or the RTU Configurations Advanced Tabular Display.
c. The applied V tag must be in the inactive state before testing can occur.
d. The SCADA DBA shall request that the abnormal state of the status point be sent. A change of state alarm for that point should be received in SCADA. The SCADA DBA shall acknowledge receipt of the “Abnormal” status indication to field personnel.
e. The SCADA DBA shall request that the normal state of the status point be sent. A change of state alarm should be noted in SCADA. The SCADA DBA shall acknowledge receipt of the “Normal” status indication to field personnel.
f. If the control tested successfully the V tag can be removed and the point left if scan.
g. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the point list with as much detail as is available.
h. A status point that fails testing should remain out of scan with the V tag active.

9.1.5.5. <u>Analog point checkout</u>

a. The SCADA DBA shall confirm with field personnel that the initial indicated analog value and the field value of the device agree.
b. Analogs points should be verified from both the Substation Analog Display and the RTU Configuration Advanced Tabular Display.
c. The applied V tag must be in the inactive state before values can be verified.
d. The SCADA DBA shall confirm with field personnel that the polarity (direction of current flow) of the indicated analog values sign and the polarity of the field value of the device agree.
e. The SCADA DBA shall confirm with field personnel that the directional arrow on the display reflects the correct polarity of the analog value displayed.
f. If engineering unit values in the field do not agree with those displayed on the display, raw counts should be compared, and scaling factor should be verified for accuracy.
g. If the analog point verified successfully the V tag can be removed and the point left if scan.
h. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the point list with as much detail as is available.

9.1.5.6. <u>Accumulator checkout</u>

a. The SCADA DBA shall confirm with field personnel that the Accumulator points are updating.

b. The SCADA DBA shall confirm with field personnel that accumulated raw counts in the last 5-minute period agree with those on displayed on either the Accumulator Detail display or RTU Configuration Advanced Tabular Display.
c. A failed test should be noted on the Post SCADA Checkout Report (PSCOR) and on the point list with as much detail as is available.
d. An analog point that does not verify as accurate should remain out of scan with the V tag active.

9.1.6. Check out Completion

9.1.6.1. Checkout Cleanup

a. The SCADA DBA will verify that all status and control points that have been checked out are in their normal state. If a point is found to still be in the abnormal state, the SCADA DBA shall verify with field personnel whether the alarm is in fact valid and report findings to the System Operator.
a. The SCADA DBA will verify that all alarms on the Active Alarm Summary associated with or that were generated as a result of checkout have been either acknowledged and verified as valid and reported to the System Operator or deleted from the Active Alarm Summary.
b. The SCADA DBA will verify that all analog polarity and directional arrows are accurate.
c. The SCADA DBA will verify that all "V" tags have either been removed from points that were successfully tested or made active for those point that failed checkout.
d. The SCADA DBA will verify that all breakers that were switched to LOCAL prior to testing for safety have been returned to the REMOTE position.
e. The SCADA DBA will note all coincidental loss of monitoring and control and report it to the Manger of System Operations and to System Operators.

9.2. Finalizing Database, Display and Checkout Documentation

9.2.1. POST SCADA CHECKOUT REPORT (PSCOR)

9.2.1.1. Upon completion of the checkout, with an attached Post SCADA Checkout Report (PSCOR) should be sent on the day of checkout to SOC Operators, Project Engineer(s) and Communications summarizing the status of the checkout. The report should contain a list of the following:

a. All points that were not tested.
b. All points that failed checkout.
c. All coincidental loss of monitoring and or control discovered as a result of the field work associated with the project.
d. All follow-up action items.

9.2.1.2. The Post SCADA Checkout Report (PSCOR) Excel template is located on the ASOC shared drive ME_PSCOR_091917.xltm.

9.2.2. SCADA Database Checklist (SDC)

9.2.2.1. The SDC should be finalized by noting any follow up and or action items required for the project.

9.2.2.2. SCADA Line Ratings should be validated and checked for any changes that may have incurred as a result of the field changes.

9.2.2.3. SCADA Limits should be updated with any new ratings effective with the field changes.

9.2.2.4. SDC should be attached to the point list used during checkout and filed in the appropriate station patient file.

Appendix 1 – NOMCR REQUEST FORM

A copy of the latest NOMCR Request Form (NRF) can be found on the NOMCR SharePoint Site.

Appendix 6 – SCADA Database Checklist

SCADA DATABASE CHECKLIST

DATE		FEP CHANGE ONLY ☐	
OSI RTU NAME / RTU #			
OSI STATION NAME / STATION #			
RTU TYPE / PROTOCOL			
IP ADDRESS / PORT #			
OSI CHANNEL # / STA HW ADDR			
DB BUILD EXPLORER ☐	ROLLOUT/FEP BUILD ☐	RTU CONFIG NOTES	

Check Complete/Provide Count — or Circle if N/C		
CHANNEL CONFIG CHG'D		N/C
RTU CONFIG CHG'D		N/C
RTU PROTOCOL		N/C
STATUS COUNT		N/C
ANALOG COUNT		N/C
ACCUM COUNT		N/C

STATUS

Relink status Old	☐	N/C	Link Status New	☐	N/C

ERCOT OPER____________ TNMP OPER____________ NOTIFIED OF TELEMETRY LOSS BEFORE RELINKING OLD POINTS! ☐ COMMENT:

ANALOGS

Link Analog Old	☐	N/C	Link Analog New	☐	N/C
Chg Scale Factors Old	☐	N/C	Set Scale Factors New	☐	N/C
Chg Analog Type Old	☐	N/C	Set Analog Type New	☐	N/C
Verify Alarm Limit Set Old	☐	N/C	Verify Alarm Limit New	☐	N/C
			Verify Archive Flag New	☐	N/C

TELEMETERED ACCUMULATORS

Relink Accums Old	☐	N/C	Link Accums New	☐	N/C

CALC ACCUMS FOR TIE POINTS

re-config alt calc accums old	☐	N/C	config calc accums new	☐	N/C

CONTROLS

Relink Controls Old	☐	N/C	Link Controls New	☐	N/C

DISPLAYS

Update 1-Line Old	☐	N/C	Create/update 1-Line New	☐	N/C
Update Overview Old	☐	N/C	Add Station To Overview	☐	N/C

MVA & POWER FACTOR

Relink MVA & PF Old	☐	N/C	Link MVA & PF New	☐	N/C

TOA / MULTISPEAK (DIST)

Remove Multispeak Old	☐	N/C	Link Multispeak New	☐	N/C

BUS NET MW & MVAR POINTS

update existing Bus Net calc	☐	N/C	Add Bus Net MW New	☐	N/C
UPDATE CALC CHG SEQ LOG	☐	N/C	Add Bus Net MVAR New	☐	N/C

FLAT LINE POINTS

Config Flat Line Pts Old	☐	N/C	Config Flat Line Pts New	☐	N/C

ALT DATA SOURCE POINTS

re-config alt data source old	☐	N/C	config alt data source new	☐	N/C

RATINGS

SCADA LINE RATINGS CHECKED	☐	
SCADA LIMITS UPDATED WITH NEW RATINGS N/C	☐	DATE: /

COMMUNICATIONS

COMM TECHS FOR FEP CHANGES ONLY:

PROJECT/CHANGE DESCRIPTION

DISTRIBUTION CKT TRIP RATINGS

Circuit Number	Rating	Complete

TOA/MULTISPEAK NAMES

Multispeak Name	Device Name	Complete

ICCP

ICCP Device	SCADA Pt	Complete

ICCP PTS VERIFIED UPDATING WITH ERCOT DATE: / / ☐

NOTES/ACTION ITEMS/FOLLOW UP

Appendix 7 – RATING AND IMPEDANCE CHANGE REQUEST (RICR)

RATING AND IMPEDANCE CHANGE REQUEST

	September 17, 2019
	Ross Cloninger

M-69-C1, M-69-C2 & M-69-C3	ERCOT LINE OR TRF NAME	M-69-C1, M-69-C2 & M-69-C3
1-1/0 ACSR	VOLTAGE	69000

NOTE: Enter voltage without decimals i.e. 69000 or 138000

STATION/BUS CHANGE

PSSE Bus #	PSSE Bus Name	Planning Area	Owner/Operator	Planning Zone	Service Level	Voltage Limits (SOL)	NORMAL HIGH	NORMAL LOW	EMERGENCY HIGH	EMERGENCY LOW
38285	TNKERMIT1_0	TNMP_TSP (17)	TNMP (1050)	TNP_PMWK (229)	69000	TNM1	72450	62790	72450	59340
38280	TNKERMTTP_0	TNMP_TSP (17)	TNMP (1050)	TNP_PMWK (229)	69000	TNM1	72450	62790	72450	59340

LINE RATINGS CHANGE

LINE NAME	FROM BUS #	TO BUS #	Amb Temp (deg F)	CONTINUOUS CONDUCTOR RATING AT 75C COND TEMP		15-MIN CONDUCTOR RATING AT 75C COND TEMP		MOST LIMITING TERMINAL EQUIPMENT CONTINUOUS RATING		MOST LIMITING TERMINAL EQUIPMENT 15-MIN RATING		IMM RATINGS (MVA)			
				MVA	AMP	MVA	AMP	MVA	AMP	MVA	AMP	NRML (RATE A)	2-HOUR EMERG (RATE B)	15-MIN	COND (RATE C)
M-69-C1	37920	38280	STATIC	29	243	31	259	29	243	31	259	29	29	31	29
M-69-C3	38250	38280		29	243	29	243	29	243	29	243	29	29	29	29
M-69-C1	37920	38280		29	243	29	243	29	243	29	243	29	29	29	29
M-69-C2	38280	38285		29	243	29	243	29	243	29	243	29	29	29	29
M-69-C3	38250	38280		29	243	29	243	29	243	29	243	29	29	29	29

or rating calculated using 25C ambient temperature and 75C conductor temperature

LINE IMPEDANCE CHANGE

FROM BUS #	TO BUS #	Line Voltage	Miles Length	Line Impedance					
				PSSE			ERCOT		
				Per Unit Resistance(R)	Per Unit Reactance(X)	Per Unit Bch (Charging)	Ohms Resistance(R)	Ohms Reactance(X)	Siemens Bch (Charging)
37920	38280	69000	10.36	0.2491490	0.1951900	0.0027300	11.8619839	9.2929959	0.0000573
38250	38280	69000	1.23	0.0295800	0.0231700	0.0003200	1.4083038	1.1031237	0.0000067
37920	38280	69000	9.69	0.2280000	0.1827000	0.0025750	10.8550800	8.6983470	0.0000541
38280	38285	69000	0.49	0.0115000	0.0092380	0.0001300	0.5475150	0.4398212	0.0000027
38250	38280	69000	0.73	0.0172000	0.0138000	0.0001940	0.8188920	0.6570180	0.0000041

Miles Length	Line Impedance Check					
	ERCOT			PSSE		
	Ohms Resistance(R)	Ohms Reactance(X)	Siemens Bch (Charging)	Per Unit Resistance(R)	Per Unit Reactance(X)	Per Unit Bch (Charging)
				0.0000000	0.0000000	0.0000000
				0.0000000	0.0000000	0.0000000
				0.0000000	0.0000000	0.0000000
0	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000

PSSE Bus To	PSSE Name From	PSSE Name To	STATUS
38280	TNWINK____0	TNKERMTTP_0	NORMALLY CLOSED
38285	TNKERMTTP_0	TNKERMIT1_0	NORMALLY CLOSED
38280	TNKERMIT2_0	TNKERMTTP_0	NORMALLY OPEN

CONTINUOUS CONDUCTOR RATING AT 75C COND TEMP		15-MIN CONDUCTOR RATING AT 75C COND TEMP		MOST LIMITING TERMINAL EQUIPMENT CONTINUOUS RATING		MOST LIMITING TERMINAL EQUIPMENT 15-MIN RATING		IMM RATINGS (MVA)			
MVA	AMP	MVA	AMP	MVA	AMP	MVA	AMP	NRML (RATE A)	2-HOUR EMERG (RATE B)	15-MIN	COND (RATE C)
0		0		0		0		0	0	0	0
0		0		0		0		0	0	0	0

culated using 25C ambient temperature and 75C conductor temperature

PSSE BUS #	Load ID	Load Planning Area	Load Planning Zone	Conforming/Non-Conforming	Ownership	Operatorship	COMMENT
38280	1	TNMP_TSP (17)	TNP_PMWK (229)	CONFORMING	TNMP (1050)	TNMP (1050)	LOAD PARAMETERS REMAIN THE SAME, JUST TRANSFERRED TO NEW BUS NUMBER.
38285	1	TNMP_TSP (17)	TNP_PMWK (229)	CONFORMING	TNMP (1050)	TNMP (1050)	

REASON FOR CHANGE/UPDATE

TWEEN WINK TO KERMIT # 1 AND KERMIT # 2. ASSOCIATED WITH TNMP LINES M-69-C1, M-69-C2 AND M-69-C3.
request was already discussed with Heidi.

ATTACHMENTS

ERCOT NOMCR #	
ERCOT MODEL LOAD DATE	
NOMCR SUBMISSION DATE	
NOMCR SUBMITTED BY	

Appendix 8 – NOTIFICATION OF ANTICIPATED MODEL CHANGE (NAMC)

NOTIFICATION OF ANTICIPATED MODEL CHANGE
(NAMC)

SUBMISSION OF THIS FORM DOES NOT MEAN YOUR NOMCR HAS BEEN SUBMITTED

Update and Attach drawing as directed below and Save file as A **MACRO ENABLED SPREADSHEET** with a name like "project_name_date" and email request to ASOC. If you are unable to attach a drawing, please send drawings as email attachment. example: Heights_T2_Replacement_11112020. Email completed form to: ca-TNMPNOMCRS@pnmresources.com

DATE OF REQUEST:		ASOC USE ONLY - BLACKSTART PLAN IMPACT
PROJECT NAME:		
PROJECT MANAGER:		
PROTECTION ENGINEER:		
COMMISIONING ENGINEER:		
DISTRIBUTION ENGINEER:		
DESIRED MODEL LOAD ERCOT MODEL LOAD		
Will this project require sequencing/phases?		
Will a shoofly or temporary jumper be utilized during construction?		
Will a Mobile TRF be utilized during construction ? (Choose Yes or No from Drop Down. Include connections for the mobile TRF and mobile switching devices on the NOMCR drawing.)		Anticipated Energize Date of Mobile TRF:
PROJECT DESCRIPTION: Describe in detail the overall scope, construction and energization plan for this NOMCR project. Provide detailed description of multi-stage transition plans in each phase below. Attach additional sheets if necessary.		

Transmission Substation Facilities Added or Affected by this Project

NEW SUBSTATIONS			
EXISTING SUBSTATIONS			
NEW & EXISTING SUBSTATION POI's			

Comments or Additional Information as needed:

POINTS OF INTERCONNECT (POI'S)

For new or existing POIs, describe in detail the plan to Establish, Terminate, or Relocate the POI with the neighboring utility (i.e. AEP, BRAZOS, CENTERPOINT, ONCOR etc.). Please include available employee contact information, schedule dates and attach any preliminary or final interconnect agreements or drawings you might have for adjacent facilities.

Project Completion Plan

List all NEW and EXISTING devices at each affected Substation (TNMP owned and/or adjacent POIs) that will be outaged or energized during each phase of the project. Include ALL Equipment (i.e. Breakers, Switches, Transformers, Capbanks, Loads, DG facilities, Metering, Shoo-fly, POIs etc.), Lines and Relaying in/to/from adjoining stations that may be coincidentally affected during construction. List any TEMPORARY SHOO-FLY/JUMPERS that will be used to ensure power flow during transitions and clearly mark their location on attached drawings.

Intermediate progress dates and plans for each incremental phase are required by ERCOT for Real-Time Contingency Analysis, to validate Scheduled Outages for this project and for accurate NOMCR submittal.
Failure to provide incremental energization plans may result in Denial of Outages by ERCOT and subsequent Delays in Energization.
Please indicate your transition plans below with separate start and completion dates for each phase. Phases should correlate with planned Operations Outage submittals.

PHASE 1 DESCRIPTION				Comments or Additional Information as needed:
PHASE 1 ESTIMATED START DATE		PHASE 1 ESTIMATED COMPLETION DATE		
PHASE 2 DESCRIPTION				Comments or Additional Information as needed:
PHASE 2 ESTIMATED START DATE		PHASE 2 ESTIMATED COMPLETION DATE		
PHASE 3 DESCRIPTION				Comments or Additional Information as needed:
PHASE 3 ESTIMATED START DATE		PHASE 3 ESTIMATED COMPLETION DATE		
PHASE 4 DESCRIPTION				Comments or Additional Information as needed:
PHASE 4 ESTIMATED START DATE		PHASE 4 ESTIMATED COMPLETION DATE		
PHASE 5 DESCRIPTION				Comments or Additional Information as needed:
PHASE 5 ESTIMATED START DATE		PHASE 5 ESTIMATED COMPLETION DATE		
PHASE 6 DESCRIPTION				Comments or Additional Information as needed:
PHASE 6 ESTIMATED START DATE		PHASE 6 ESTIMATED COMPLETION DATE		
PHASE 7 DESCRIPTION				Comments or Additional Information as needed:
PHASE 7 ESTIMATED START DATE		PHASE 7 ESTIMATED COMPLETION DATE		

Attach a SEPARATE drawing for EACH PHASE of the project. A mark up of each phase on the final configuration drawing with notes indicating what will energize at each stage would be adequate.

ATTACH DRAWING Place cursor in a red box PRESS ATTACH DRAWING	Place Cursor Here	Place Cursor Here	Place Cursor Here	Place Cursor Here	Place Cursor Here	Place Cursor Here

The NAMC is used to notify SOC of planned TNMP Transmission System topology changes that must be represented in the ERCOT Operations Model. The information contained herein and attached drawings will be used to initialize a NOMCR REQUEST FORM (NRF) that will be routed back to you for detailed data entry via SharePoint workflow in the NOMCR Information Tracking System (NITS). When all required data has been collected in the NRF a NOMCR will be submitted to ERCOT on your behalf and you will be notified of the pending model load date. Please make sure the data you provide is accurate and complete so as not to delay the NOMCR submission.

Appendix 10 – SIGNED DOCUMENT REVIEW PAGE

Texas New-Mexico
Power Company Network Model and SCADA Maintenance Process v4
Internal

Appendix 10 – SIGNED DOCUMENT REVIEW PAGE

Document Review

- This document shall be reviewed annually for completeness
- Reviews shall be coordinated by the SCADA Engineering Department and shall include all relevant personnel
- Revisions to this plan will be tracked using MS Word track changes feature and noted as applicable in the revision history table on page 1 If no changes are made, the annual review shall be reflected in the Revision History and the document will be re-executed by the Director of System Engineering
- This document shall be approved by the Director of System Engineering by signing and dating below
- A DocMinder notification shall be used as an internal control to ensure timely reviews are conducted of this document
- The latest signed copy of this page can be found in *Appendix 10 – SIGNED DOCUMENT REVIEW PAGE*

	February 6,2025	February 6, 2025
Associate Director, System Engineering	**Approval Date**	**Implementation Date**