ISO New England Operating Procedure No. 18

Metering and Telemetering Criteria (OP-18)

Effective Date: September 28, 2023

Review By Date: September 28, 2025

REFERENCES:

ISO New England Inc. Transmission, Markets, and Services Tariff Section I - General Terms and Conditions Section I.3.9 Review of Market Participant's Proposed Plans

ISO New England Market Rules and Procedures

ISO New England Planning Procedure No.11 - Planning Procedure to Support Geomagnetic Disturbance Analysis (PP11)

ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14)

ISO New England Operating Procedure No. 17 - Load Power Factor and System Assessment (OP-17)

ISO New England Manual for Market Rule 1 Accounting Manual M-28 (Manual M-28)

ISO New England Manual for Definitions and Abbreviations Manual M-35 (Manual M-35)

ISO New England Manual for Registration and Performance Auditing Manual M-RPA (Manual M-RPA)

NERC IRO-002 - Reliability Coordination – Monitoring and Analysis

NERC IRO-010 - Reliability Coordinator Data Specification and Collection

NERC IRO-018 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities

TABLE OF CONTENTS

APPENDICES:

I. PURPOSE

This Operating Procedure (OP) establishes standards for metering (measurement) and telemetering (data transmission) for the purposes of ISO New England (ISO) dispatching, market settlement, Transmission Owner (TO), Local Control Centers (LCCs) and Market Participant (MP) peak load determination, factors that impact voting shares and load power factor (lpf) measurement. This OP identifies the power system parameters that each TO and MP are to meter and/or telemeter. This OP also establishes standards to verify that the equipment that each TO or MP installs can provide an appropriate level of accuracy and/or appropriate recordings for audit purposes. This OP further prescribes maintenance procedures and schedules to be followed by each TO and MP so that the attainable level of accuracy may be realized.

There may be additional metering and telemetering requirements established by local state utility control and distribution utilities.

II. ACRONYMS & DEFINITIONS

ISO CFE: Market Participant Communications Front End

CNP: Communication Network Processor

Fiducial Value: A value to which reference is made in order to specify the accuracy of a transducer. The Fiducial Value is the span except for transducers having a symmetrical reversible input and output. In this case, the Fiducial Value is half the span. (Reference: ANSI/IEEE 460-1988, lapsed) Examples below:

- Above the term “symmetrical reversible” means that the positive and negative full scale are equal in magnitude while opposite in polarity and halfway in the span is zero (0).
- An AC Watt and/or VAr transducer where the inputs (voltage and current) are bidirectional (due to their nature of being ac) and where the values Watts and VArs that would be derived from them based upon magnitude and angle difference are also bidirectional would therefore mean the Fiducial Value half span (the value of positive full scale). Given an example scale of -810 MW to 0 to +810 MW and an absolute error of 7 MW would yield a % error of 0.86% (7 MW / 810 MW) meaning the Fiducial Value would be 810 MW.
- A transmitter device (such as the RFL 9800 series transmitter) that takes a signal representing a telemetered MW and outputs a frequency shifted by the input would have a Fiducial Value of the full span independent of the input since the output is between a min and max frequency. Given an example input scale of -300 MW to 0 to +300 MW via a -5V to 0 to +5V input signal and the associated output scale being 10 Hz to 20 Hz to 30 Hz, because the output is **not** reversible the Fiducial Value of the output is 20 Hz (Span = 30 Hz – 10 Hz). In that example if the absolute error in frequency was 0.5 Hz, the % error would be 2.5% (0.5 Hz / 20 Hz). The receiver would similarly have its input as **not** being symmetrically reversible and so the Fiducial Value would be the full span.
- An AC Volt transducer has a symmetrical reversible input due to it being ac but the output would be unidirectional (zero to full scale) and as such, the Fiducial Value would be the full span but in that case, the full span is equal to the positive full scale as there is **no** negative side to the scale. Therefore, effective accuracy is similar to the Watt/VAr

transducer example where the positive full scale ends up being in the denominator.

GIC: Geomagnetically Induced Current

HVDC: any DC equipment that operates at 100kV or above.

ICCP: Inter-Control Center Communications Protocol

LCC: Local Control Center

Modified: Modified or modify is defined for purposes of this Operating Procedure for new and Non-Emergency Replacement Equipment. For SCADA substation communications only, examples of this would include non-emergency changes to NERC Bulk Electric System (BES) RTUs and expansion of BES substation facilities that include new BES RTU inputs. Periodic maintenance of RTUs such as software updates would not be considered to be “modified”.

MP: Market Participant

Non-Emergency Replacement Equipment: is any equipment that does not interrupt or alter the flow of data critical to system operation when it fails and that, as such, does not need to be returned to service immediately. This equipment has been categorized as maintenance priorities B and C in Table 1 of Appendix A to ISO New England Operating Procedure No. 2 (OP-2A). As provided for in OP-2A, the maintenance priority of any equipment not included in Table 1 shall be determined on a case-by-case basis by the ISO, the LCC, and SCADA TOs.

RTU: Remote Terminal Unit. Field station device to provide or receive telemetry to or from LCC or SCADA Servers.

SCADA: Supervisory Control and Data Acquisition

SCADA Server: A server running a SCADA application which communicates with RTU's and other systems to acquire data required by this OP.

SCADA TO: any LCC or a TO that owns and maintains SCADA Servers, designated by ISO, as described above. LCCs or SCADA TOs are:

- Central Maine Power (TOP/LCC)
- Eversource (CONVEX, NSTAR and PSNH; TOP/LCC)
- National Grid (REMVEC; TOP/LCC)
- VELCO (TOP/LCC)
- United Illuminating (TO only)
- Versant (TO only)
- Rhode Island Energy (TO, currently National Grid is TOP providing SCADA servers)

STN (Shared Telecommunications Network): The STN is the network resulting from the interconnection and sharing of the private telecommunications systems and networks owned by the TOs.

Telemetering (telemetry): Transmission of measurable quantities using telecommunication techniques. (reference: IEEE 610.2-1987, including analog and digital below)

- **Analog -** Telemetering in which some characteristic of the transmitter signal is proportional to the quantity being measured.
- **Digital -** Telemetering in which a numerical representation is generated and transmitted, the number being representative of the quantity being measured.

Tie-Line Assets: A physical transmission line which connects a TO/MP to another TO/MP, a non-MP or the 345 kV (or above) Pool Transmission Facility (PTF) system. Tie-Line Assets are also used to connect different sections of a TO/MP system that is divided by a Load Zone boundary. This definition supplements that contained in Tariff Section I – General Terms and Conditions.

TO: Transmission Owner

TOP: Transmission Operator

Transducer: A device that takes a signal or signals (Volts, Amps, etc.,) and converts it into another signal or signals (milli-Amps, Volts, etc.). Most often used to convert secondary Volts and/or Amp quantities into a scaled signal usable by an RTU (mA or Volt) representing system Volts, Amps, Watts, VArs or Frequency values. Digital meters and digital relays that convert signals into numerical values used for OP-18 compliance will be treated as transducers for this OP.

III. IMPLEMENTATION

A. Applicability

1. Each TO and/or MP shall have in-service all the metering, recording and telemetering equipment necessary to meet the requirements of this OP as described in Sections III.A.2 and III.A.3 of this OP.
2. For new and Non-Emergency Replacement Equipment, all requirements described in this OP shall be met on or before the date when the Resource, line, or system commences operation.
    a. The operational commencement date shall include all test power activities unless the ISO determines that compliance with the requirements is not necessary during test power activities.
    b. Starting on the operational commencement date, each TO and/or MP shall meet all testing, calibration, and maintenance requirements established in this OP.
    c. If any requirement of this OP cannot be met by the operational commencement date, then, prior to the operational commencement date, the TO and/or MP shall submit a

mitigation plan request or an exemption request pursuant to, respectively, Section III.B or Section III.C of this OP.

3. Equipment existing prior to August 7, 2020 (“Pre-existing Equipment”) shall meet the requirements of this OP as described in this Section III.A.3.
   a. Pre-existing Equipment shall meet the currently effective version of the requirements in Sections IV, V, VI, and VII of this OP.
   b. Pre-existing Equipment shall be required to be compliant with the version of the requirements in Sections VIII and IX of this OP that was in effect when the equipment commenced operation.
   c. For any Pre-existing Equipment that is found to not meet the requirements of this OP as described above in Sections III.A.3.a and III.A.3.b, the TO/MP shall submit a mitigation plan request or an exemption request within 30 calendar days of the finding.
   d. If the ISO observes that the Pre-Existing equipment shows a severe anomaly, then the ISO may require that the equipment be replaced or repaired in order for it to meet the currently effective version of all requirements of this OP.

B. Mitigation Plan Requests

1. A TO and/or MP shall submit a mitigation plan request for one or more of the requirements of this OP when a non-compliant condition is identified (as described in Sections III.A.2.c and III.A.3.c of this OP), if such condition may be corrected in order to meet the requirements of this OP.
2. Included with the request, the TO and/or MP shall provide:
   a. A list of the requirement(s) for which the mitigation plan request is being submitted.
   b. A proposed mitigation plan that describes the actions that will be taken to comply with any outstanding requirements as well as the deadlines for each of those actions.
3. The mitigation plan request shall be submitted to the ISO Participant Support and Solutions staff.
4. The ISO may request supporting documentation after it reviews the mitigation plan request.
5. The ISO, at its sole discretion, may grant or deny the mitigation plan request.
   a. If the ISO grants the mitigation plan, then the TO and/or MP shall meet the deadlines for compliance with the requirements of this OP as established in the accepted mitigation plan.
   b. For new and Non-Emergency Replacement Equipment, if the ISO does not accept the mitigation plan, then the TO or MP shall comply with the requirements of this OP on the operational commencement date described in Section III.A.2.a of this OP.
   c. For existing equipment, if the ISO does not accept the mitigation plan, then the TO or MP shall revise the mitigation plan as directed by ISO.

6. Upon completion of the accepted mitigation plan, the TO and/or MP shall notify the ISO Participant Support and Solutions staff, which shall confirm that the mitigation plan has been completed.

C. Exemption Requests

1. A TO and/or MP shall submit an exemption request for one or more of the requirements of this OP if a non-compliant condition is identified (as described in Sections III.A.2.c and III.A.3.c of this OP).
2. Included with the exemption request, the TO and/or MP shall provide:
   a. A list of the requirement(s) for which the exemption is being requested.
   b. An explanation of how the unique configurations of a Resource, line, or system would justify the exemption.
3. The exemption request shall be submitted to the ISO Participant Support and Solutions staff.
4. The ISO may request supporting documentation after it reviews the exemption request.
5. The ISO, at its sole discretion, may grant or deny the exemption request.
   a. If the ISO grants the exemption request, then the TO and/or MP shall not be required to meet the requirements of this OP for which the exemption is granted. ISO may grant exemptions for up to five years from the date of the exemption approval. Before the exemption reaches its end date, the ISO shall review the exemption to determine whether significant changes that warrant revocation of the exemption have occurred. If no such changes have occurred, then the ISO may, at its sole discretion, renew the exemption for up to five years from the date of renewal. The ISO shall review the renewed exemption before it reaches its end date.
   b. For new and Non-Emergency Replacement Equipment, if the ISO denies the exemption request, then the TO or MP shall comply with the requirements of this OP on the operational commencement date described in Section III.A.2.a of this OP.
   c. For existing equipment, if the ISO denies the exemption request, then the TO or MP may submit a mitigation plan pursuant to Section III.B of this OP.

IV. METERING, RECORDING AND TELEMETERING ON INTERCONNECTIONS WITH SYSTEMS OUTSIDE NEW ENGLAND

A. Overall Requirements

1. The metering, recording and telemetering requirements for each transmission line interconnecting Pool Transmission Facilities (PTF) to systems outside of New England are:
   - Metering and telemetering of instantaneous megawatts (MW) from the agreed upon metering terminals of the line
   - Metering and telemetering of instantaneous megavars (MVAr) from the agreed-upon metering terminals of the line [except for High Voltage direct current (HVdc) interconnection])

- Metering, recording and telemetering of megawatt hours (MWh) per hour (i.e. energy per hour)

2. MW and MWh per hour metering shall be at the same terminal of each interconnection.
3. The TO/MP and the non-TO/MP shall agree on the location of the metering terminal(s).
4. Wherever feasible, both technically and economically, Data transmission in the ISO Reliability Coordinator Area/Balancing Authority Area (RCA/BAA) should be via the New England Shared Telecommunications Network.

B. Instantaneous Megawatts and Megavars

1. This data shall be telemetered to ISO.
2. This data may also be required by other dispatch centers within either system and by systems beyond the interconnecting systems.
3. For new interconnections, and any upgrades of existing equipment, currently supportable telemetering equipment shall be used and quantities shall be transmitted to each receiver location directly without retransmission (i.e., without an intermediate receiver and transmitter).

C. Megawatt-hours per Hour

1. There shall be a device at each interconnection facility to record the hourly billing watt-hours on site. In all new and upgraded installations, solid-state data recorders shall be installed.
2. The MWh data shall be telemetered hourly to either ISO or the control center of the interconnected system. If it is telemetered to ISO, it shall be telemetered via the applicable LCC or SCADA TO, that has responsibility for the particular interconnection line.
3. The watt-hour data shall be compensated for line losses to the ISO RCA/BAA boundary.
4. MWh may be recorded and telemetered as a net or as two quantities, MWh IN and MWh OUT.

V. METERING AND RECORDING FOR SETTLEMENTS

A. Overall Requirements

1. MWh per hour (i.e. energy per hour) data is required for each Generator Asset, Tie-Line Asset and Load Asset. There is an option for Generator Assets, Tie-Line Assets and Load Assets, subject to appropriate authorization, to have metering data submitted at the subhourly 5-minute interval. The 5-minute data reported shall be calculated by measuring the generation or consumption energy in units of MWh in the 5-minute interval and multiplying that value by 12 (resulting in an average generation or consumption in units of MW during the interval). This 5-minute subhourly data reporting option shall also apply to all other settlement Watt-hour (Wh) and MWh requirements.
2. In order for an Asset to be eligible to participate in one or more of the markets, the Asset shall have Wh metering as defined in this OP. The exception to this is in the case of intra-MP Tie-Line Assets as defined in Section V.D.2 of this OP.
3. For Demand Response Resources (DRR), MWh per 5-minute interval data is required for each Demand Response Asset (DRA). The 5-minute data reported shall be calculated by measuring the consumption or generation in the 5-minute interval and

multiplying that value by 12 (resulting in an effective hourly consumption or generation). In order for a DRA to be eligible to participate in one or more of the markets, the DRA shall have a Wh metering or recording device as defined in this OP.

B. Wh Metering and MWh per Hour Data

1. New and upgraded Wh metering installations shall conform to the requirements in Section VIII of this OP.
2. The hourly MWh per hour data shall be submitted to ISO in accordance with ISO New England Manual for Market Rule 1 Accounting Manual M-28 (Manual M-28).
3. For Tie-Line Assets: the hourly MWh per hour data may be recorded for a given Asset as two quantities, MWh IN and MWh OUT, but shall be submitted to ISO as a net quantity.
4. The MWh per hour data quantities shall be automatically recorded at **no** greater than an hourly interval in accordance with Section VIII.B.5 of this OP. If the option for submitting 5-minute interval data is used, the quantities shall be automatically recorded at **no** greater than the 5-minute interval.
5. Wh meters shall be equipped with kilowatt-hour (kWh) or MWh registers which shall be read a minimum of once a month. The purpose of this register read is to validate hourly data and allow for an adjustment, which corrects the sum of the hourly readings submitted to ISO during the month to the total energy actually metered. (See section X.D.7 for required energy comparison)
6. The location of applicable Wh metering shall comply with this OP and be reported to ISO by the responsible MP.
7. The hourly MWh per hour data or subhourly data shall be reported to ISO to reflect the Asset at the Interconnection Point. For purposes of this OP, the Interconnection Point is hereafter defined as:
   i. the PTF boundary;
   ii. the agreed upon point of interconnection between two TOs/MPs; or
   iii. the agreed upon point of interconnection between a TO/MP and a non-MP.

   Wh meters **not** located at the Interconnection Point shall be compensated for losses to the Interconnection Point as follows:

a) Level I accuracy

   Wh metering that is:

   - physically located at the Interconnection Point, or
   - **not** physically located at the Interconnection Point but continuously compensated within the Wh meter or Wh metering circuit for excitation and load losses to the Interconnection Point.

b) Level II accuracy

   Wh metering that complies with this OP, except that it is **not** physically located at the Interconnection Point, but the recorded meter data is compensated through external calculations for excitation and load losses to the Interconnection Point. The integration interval for the loss compensation calculations shall **not** exceed a one-hour period, Compensation calculations shall be based on both real power (kW) and reactive power (kVAr or kQ) measurements. Voltage may be either measured or assumed constant.

c) Level III accuracy

Existing Wh metering without reactive recording capability that complies with this OP, and is **not** physically located at the Interconnection Point, may have its MWh recorded meter data compensated through external calculations for excitation and load losses to the Interconnection Point. In such cases, the compensation calculations shall be based on real power (kW) measurements, a fixed 95% power factor, and voltage may be either measured or assumed constant. The integration interval for the loss compensation calculations shall **not** exceed a one-hour period.

8. For DRAs, the 5-minute (MWh) data submitted to the ISO in accordance with Manual M-28 shall be either energy billing quality as defined in OP-18, Appendix C - Minimum Accuracy Standards For New And Upgraded Metering, Recording And Telemetering Installations And For Calibration Of Existing Equipment (OP-18C) or in the case where metering is installed specifically for the DRA (and will **not** be used for utility billing purposes), a metering system with an overall accuracy as defined in OP-18C may be used. Metering used for utility billing purposes is also known as revenue quality metering.

9. DC coupled Assets participating in one or more of the markets separately must meet the following requirements:
   a) DC Wh metering must be installed for each Asset.
   b) AC Wh metering compliant with this OP must be installed at or compensated to the Interconnection Point.
   c) Reported interval MWh per hour values for each DC coupled Asset must sum to the measured AC MWh per hour compensated to the Interconnection Point in each interval.
   d) Both unadjusted DC MWh per hour values and reported interval MWh per hour values for each DC coupled Asset shall be made available to all Lead MPs for the Assets prior to reporting to ISO.

C. Generator Assets

1. Generator Assets directly connected to the 345 kV (or above) PTF system shall be metered at the PTF boundary or compensated to the PTF boundary in accordance with Section V.B of this OP.

2. Generator Assets directly connected to the PTF system at 230 kV or below where PTF boundary metering is used shall be metered at the PTF boundary or compensated to the PTF boundary in accordance with Section V.B of this OP.

3. Generator Assets directly connected to the PTF system at 230 kV or below where PTF boundary metering is **not** used shall be metered at:

   (i) the generator terminals in accordance with the terms of the applicable Interconnection Agreement,

   (ii) at the PTF boundary; or

   (iii) compensated to the PTF boundary in accordance with Section V.B of this OP.

4. Generator Assets **not** connected to the PTF system shall be metered at the Interconnection Point or compensated to the Interconnection Point in accordance with Section V.B of this OP. The Interconnection Point shall be determined in accordance with the terms of the applicable Interconnection Agreement.

D. Tie-Line Assets

1. Tie-Line Assets shall have a Wh meter or in the case of intra-TO/MP tie-lines an instantaneous watt meter to calculate Wh at the Interconnection Point or compensated to the Interconnection Point with the other TO/MP or non-MP unless otherwise agreed to by the parties involved or the PTF boundary as appropriate and in accordance with Section V.B of this OP.
2. Intra-TO/MP tie-lines are Tie-Line Assets used to connect different sections of a TO/MP system that is divided by a Load Zone boundary. For these Tie-Line Assets, MWh per hour data derived from integrating instantaneous MW data used for Dispatch purposes (Section VI.) is acceptable provided the metering equipment meets the minimum accuracy standards defined in OP-18C.

E. Load Assets

1. Every Load Asset except DRAs shall have a Wh meter or be determined on an hourly basis as an allocation of Wh meters. The Wh meter shall be located either at the Interconnection Point or compensated to the Interconnection Point in accordance with Section V.B of this OP.
2. The load that is measured by a TO/MP Load Asset metering system may include PTF losses. If the Load Asset metering system includes such PTF losses, these losses, as determined by the ISO State Estimator (SE) in accordance with the procedures embodied in Manual M-28, shall be supplied to the TO/MP by ISO, and shall be subtracted from the total load as metered, to determine a TO/MP non-PTF demand.

VI. INTERNAL NEW ENGLAND METERING AND TELEMETERING FOR DISPATCH, MARKET, AND RELIABILITY PURPOSES

A. Generator Asset, Alternative Technology Regulation Resources (ATRR) and Load Telemetering Criteria

Metering, as set forth below, is required for all Generator Assets and Load Assets (excluding DRAs) that are modeled and defined in the ISO Energy Management System (EMS) and are eligible to participate in the hourly markets. The metering shall measure the Generator Asset or Load Asset as it is offered or bid in the markets in accordance with OP-14. Additionally, if any change is made to an existing facility, the facility shall continue to conform to the requirements set forth below.

The following quantities are to be telemetered:

1. Market requirements:
   a) Generator Asset net (Net_1) MW, net (Net_1) MVAr and generator step-up (GSU) transformer high and low-side breaker status shall be telemetered. Refer to OP-18, Appendix D - OP-18 Metering and Telemetering Diagrams (OP-18D) for definition of Net_1. In a combined cycle configuration modeled as a single Asset in the markets, the total net output (Net_2) shall be telemetered.
   b) Dispatchable Asset Related Demands (DARDs) MW shall be telemetered.

c) Generator net (Net_3) MW and (Net_3) MVAr status shall be telemetered for Pseudo Combined Cycle Generators. Refer to OP-18, Appendix E - OP-18 Metering and Telemetering for Pseudo Combined Cycle Generator (OP-18E) for definition of Net_3.

d) **No** telemetering is required for Generator Assets receiving Settlement Only Resource treatment and generators **not** registered in accordance with OP-14**.**

e) ATRR MWs (NetPOI) shall be telemetered. ATRR telemetry shall be located at the Point of Interconnection(s) or, for ATRRs located behind Retail Delivery Point(s), telemetry shall be located at the Retail Delivery Point(s). Any exception to this locational requirement is limited to non-aggregated ATRRs and is subject to approval by the ISO. MVAr shall be telemetered for non-aggregated ATRRs with a maximum regulation capacity of 20 MW injection/consumption or larger and for aggregated ATRRs with a maximum Regulation capacity of 75 MW injection/consumption or larger. Automatic voltage regulation (AVR) indicator, which indicates whether the ATRR(s) and/or flexible alternating current transmission system (FACTS) device(s) is/are in automatic voltage regulating mode and regulating voltage, and kV data may be required to be telemetered, as determined on a case-by-case basis based on bulk power system (BPS) monitoring and operations requirements and also based on how ISO models the Asset.

NOTE

OP-18, Appendix G - Price Responsive Demand RTU Specification (OP-18G), is a confidential document subject to the ISO New England Information Policy. If access to OP-18G is needed, contact ISO Participant Support and Solutions as detailed on the ISO external website.

f) For DRAs, MWh per 5-minute interval shall be telemetered and shall meet the requirements specified in OP-18, App G. The MWh per 5-minute data to be reported shall be calculated by measuring the consumption or generation in the 5-minute interval and multiplying that value by 12 (resulting in an effective hourly consumption or generation). For settlement purposes, revised MWh per 5-minute interval shall be submitted through the appropriate Market User Interface (MUI) as defined in ISO New England Manual for Definitions and Abbreviations Manual M-35 (Manual M-35). In addition to 5 minute data, any DRA providing TMSR or TMNSR shall supply 1 minute or less MW telemetry at the retail delivery point.

g) Other data may be required to be telemetered, as determined on a case-by-case basis based on bulk power system (BPS) monitoring and operations requirements and also based on how ISO models the Asset. The determination of the data that shall be telemetered shall be made jointly by ISO, the LCC/SCADA TO and the MP.

h) GIC made up of the DC component of the neutral current in amperes from each GSU transformer subject to the requirements of Section 3.12 of ISO New England Planning Procedure No. 11- Planning Procedure to Support Geomagnetic Disturbance Analysis (PP11). The measured GIC value shall have the following direction convention: a positive sign shall indicate the GIC flows from ground into the transformer neutral, and a negative sign shall indicate the GIC flows from the transformer neutral into ground.

i) DC coupled Assets participating in one or more of the markets separately shall adhere to the following:

i. If the maximum output of the combined facility is under 5 MW and it is registered as a Settlement Only Resource, the Assets are not required to provide telemetry data pursuant to this section V.

ii. DC telemetry for each Asset shall be adjusted to the AC Interconnection Point.

iii. No MVAr values are required for low-side DC components

j) ISO may waive requirements in this section based on how ISO models the Asset. ISO shall document exemption process requests on behalf of the TO and/or MP for any waived requirements.

2. Reliability Requirements:

a) Generator Asset Net MW, and Net MVAr, as measured at the low-side of the GSU transformer. Refer to OP-18D for definition of Net. Combined cycle plants are required to supply measurements for each unit.

b) Automatic voltage regulation (AVR) indicator, which indicates whether the unit(s) and/or flexible alternating current transmission system (FACTS) device(s) is/are in automatic voltage regulating mode and regulating voltage. This includes AVR status for individual generators or synchronous condensers, which are part of a composite Asset, except for wind plants which are described in i. below.

i. For a wind plant, the AVR status indicates the combined status of all the various pieces of equipment that make up the voltage regulation system. That equipment may include Dynamic Volt-Amp Reactive (D-VAr) devices, capacitor banks, master control computers, breakers, Static VAR Compensators (SVCs), FACTS, Remedial Action Schemes (RAS) or Automatic Control Schemes (ACS) equipment, or any other equipment that contributes to the functioning of the full specified voltage regulation capability. If any of these contributing pieces of equipment are degraded or out-of-service then the AVR status indicator shall indicate “OFF”.

c) Power system stabilizer status shall be provided if installed.

d) MW and MVAr station service load values may also be requested.

e) Generator Asset terminal voltage measurements may also be requested.

f) Other telemetered data needed for ISO BPS monitoring and operation based on how ISO models the Asset shall be determined on a case-by-case basis. The determination of the data that shall be telemetered shall be made jointly by ISO, the LCC or SCADA TO.

g) ISO may waive requirements in this section based on how ISO models the Asset. ISO shall document exemption process requests on behalf of the TO and/or MP for any waived requirements.

B. Transmission System Telemetering Criteria

The following quantities shall be telemetered. Any major change to modify an existing facility shall conform to the procedures set forth below.

1. Transmission substation voltage from the following:
    a) Each generating station 50 MW or larger that connects to the 69 kV and above transmission system.
    b) Each 115 kV and above substation where two (2) or more line sections terminate with protective circuit interruption capability, such as a circuit breaker.

NOTE

The preferred measurement of bus voltage is phase-phase. In the event that phase-phase measurement is **not** provided, a phase-phase value calculated from a phase-ground measurement is acceptable.

2. Substation frequency from the following:
    a) Each station that either:
        (i) has a Designated Blackstart Resource **OR**
        (ii) has generation capability that is 50 MW or larger (nameplate).
    b) Each 230 kV and above substation.
    c) Each 115 kV substation where two or more line sections terminate with protective circuit interruption capability, such as a circuit breaker.
    d) Transmission substations not providing frequency data identified in each TO's list submitted to ISO on October 1, 2020 shall be exempt from meeting the requirements of this Section VI.B.2. Transmission substations that already provide substation frequency and are therefore not included in a TO's list shall continue to provide substation frequency as required under this Section VI.B.2. For any new transmission substations, a TO may request an exemption pursuant to Section III.C of this OP. ISO may require that a transmission substation included in a TO's exemption list meet the requirements of Section VI.B.2 if a reliability need for the data from that transmission substation arises.
3. MW and MVAr from each terminal of all non-radial inter-LCC lines.
4. MW and MVAr from every terminal of all 230 kV and above lines and at least one end of each non-radial 115 kV line.
5. MW and MVAr from each transformer connected to 115 kV and above.
6. MW and MVAr from one end of each intra-LCC line that is necessary for reliable transmission operation, to support BPS transfers, or is otherwise needed.
7. The status of each breaker 115 kV and above.
8. Any transformer with voltage regulation capability that has a low-side voltage of 115 kV or above shall provide the status of its voltage regulating state. This is commonly referenced as a load tap changer (LTC) AVR status.
9. The on-load tap changer (OLTC) tap positions of each autotransformer connected to 230 kV and above and each phase-shifting transformer connected to 115 kV and above.
10. Other telemetered data needed for ISO BPS operation (i.e., synchronous condensers, HVdc terminals, SVC, capacitor/reactor status, frequency, FACTS devices, RAS and ACS equipment and selected 69 kV switching devices) shall be determined on a case-

by-case basis. The determination of the data that shall be telemetered shall be made jointly by ISO, the LCC/SCADA TO and the MP.

11. GIC in ANDC from each transformer subject to the requirements of Section 3.12 of PP11. The measured GIC value shall have the following direction convention: a positive sign shall indicate the GIC flows from ground into the transformer neutral, and a negative sign shall indicate the GIC flows from the transformer neutral into ground.

C. Telemetered Data Scan Rates

The following minimum standards are established for the frequency at which telemetered quantities shall be scanned and made available to the local ICCP server or ISO CFE.

Frequency of Scanning (Seconds)

1. The data required for tie line MW, tie line MVAr, substation frequency, and Automatic Generation Control (AGC) operation, which includes unit MW for AGC generators and ATRR Regulation Service providers, shall be made available to the local ICCP server or ISO CFE within four (4) seconds. This time interval is measured as the time the data is scanned at the RTU until the time the data is received at the local ICCP server or ISO CFE.
2. The analog power system data, which includes all other analog data defined in Section VI of this OP, shall be made available to the local ICCP server or ISO CFE within ten (10) seconds of a change in data at a RTU. For all DRAs, data shall be submitted in 5-minute intervals. For a DRR to provide TMSR or TMNSR, DRA telemetry values shall be submitted at a minimum of every one minute. This data requirement recognizes that the change detection logic employed by some RTUs is telemetered to the SCADA system only after a change in the data is detected by the RTU, and that the amount of change may be different for each point in an RTU.
3. Telemetered status data shall be made available to the local ICCP server or ISO CFE within four (4) seconds of a change reported by an RTU.

D. Telemetered Data Criteria

The following communication paths shall be established to make the required telemetered data available. Some paths are dependent upon the Asset being defined as dispatchable per OP-14.

1. Generation data (Section VI.A) shall be made available to the LCC or SCADA TO in which the Asset resides. The LCCs and SCADA TOs shall make this data available to the ICCP network.
    a. If the Asset is dispatchable, the generation data shall also be made available to ISO via the ISO CFE (see OP-18, Appendix F - ISO Communications Front End (CFE) Interface Specifications (OP-18F). Some dispatchable types have additional data requirements as specified in OP-14 that shall also be provided to ISO. ISO shall make all of this data available to the ICCP network.
    b. If the Asset is dispatchable and the Asset nameplate generation capability as defined by the NX-12 technical data is less than 15 MW, then the LCC or SCADA TO may request an exemption to providing this data. The LCC or SCADA TO shall submit the exemption request to ISO and provide a technical explanation as to why the data **cannot** be obtained. ISO, at its sole discretion, shall grant or deny the exemption.

2. Transmission system data described in Section VI.B of this OP shall be made available by the LCC or SCADA TO to the ICCP network. This data shall also be made available to the ISO via the ISO CFE if the Designated Entity (DE) owns the transmission system equipment and the Asset is defined as dispatchable per OP-14.
3. The following Asset types from Section VI.A shall connect directly to ISO per OP-18F, or OP-18G, as applicable, to supply data:
    a. DARDs
    b. ATRRs
    c. DRAs
4. OP-18 Appendix A - ISO New England ICCP Server Node Requirement (OP-18A) defines the binary representation expected for status data types.

E. Local Control Center and SCADA TO Configuration of SCADA Servers

1. At a minimum, each LCC or SCADA TO shall provide at least one SCADA server at two separate locations at least one mile apart and each must utilize servers connected to the ICCP Network (including STN). Connections to the STN must be approved by the STN Management Committee. LCCs and SCADA TOs shall configure SCADA Servers to ensure that one is enabled and another provides equivalent standby capability.
2. Station RTU inputs to SCADA Servers for BES transmission facilities or Generation facilities with 20MVA and above nameplate capacity shall use at least two different transports for communication as in the below examples unless otherwise approved by ISO:
    - Utility fiber via physical path A
    - Commercial technology A by vendor 1
    - Utility fiber via physical path B
    - Commercial technology B by vendor 2
    - Utility technology X
3. Station RTU inputs to SCADA Servers for non-BES facilities or Distributed Generation facilities with less than 20MVA nameplate capacity shall use at least one transport listed from section VI.E.3.

NOTE

The intent of the LCC or SCADA TO providing data to the ICCP network is to ensure that the only possibility of single points of failure are individual non-redundant field devices (RTUs). For generation facilities, this also adds redundancy when the LCCs are performing the TOP function.

Figure 6-1 shows the network redundancy and network configuration that LCCs and SCADA TOs must provide for all new or existing installations that are Modified.

If an LCC, SCADA TO or Generation Facility uses commercial carriers for leased lines, then the circuits must be registered with the Department of Homeland Security (DHS) Cyber Security and Infrastructure Agency (CISA's) Telecommunications Service Priority program to ensure prioritized service and restoration, or with a comparable ISO approved program. Implementation dates are as described above.

If an LCC or SCADA TO uses cellular wireless services, then the service must be public safety grade wireless such as FirstNet.

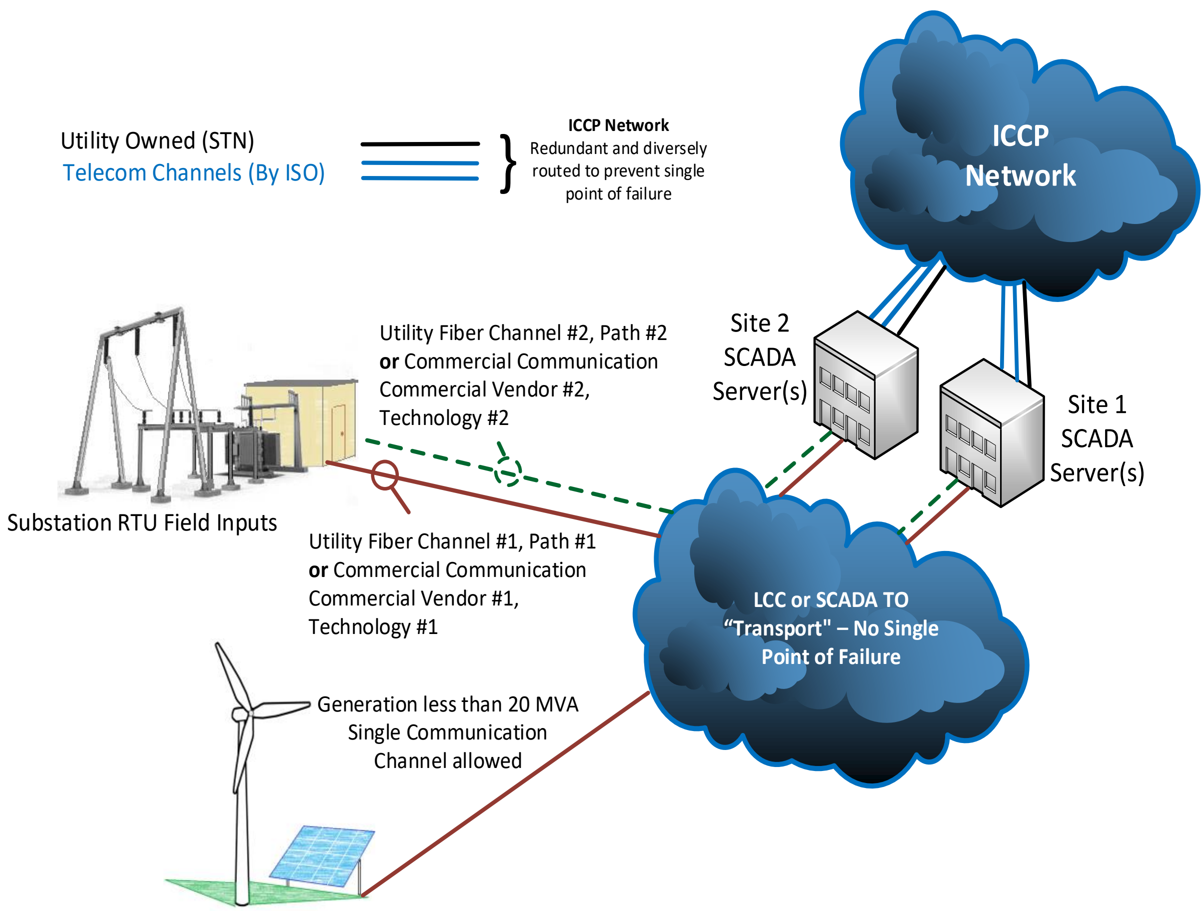

Figure 6-1 EMS/SCADA Communications Overview for New or Modified Installations

This design is for Transmission Owner NERC BES stations along with generation facilities 20 MVA and above and the intent is to eliminate single points of failure for communication pathways for a single station. Network transport devices that facilitate communications for more than one station shall also be redundant to eliminate cascading data loss from multiple stations. Dual RTUs are not necessary to meet the requirement of Figure 6-1.

In Figure 6-1 when referring to "Technology #1" and "Technology #2", these must use a different technology medium i.e. wireless 4G and wireless 5G would not be considered different technology.

NOTE

See Appendix A for other details regarding ICCP server requirements and maintenance.

LCCs and SCADA TOs shall have full SCADA Server functional equivalence at each Control Center location. There shall be no single point of failure that leads to communication loss for more than one station.

E. Non-Telemetered Data Criteria

Additional data may be determined to be necessary for the overall operation of the ISO/LCC/SCADA TO/TO/MP dispatch computer systems. This data shall originate from, and be the responsibility of, the dispatch center with jurisdiction over the data. This data shall be made available for transmission as needed to the ISO/LCC/SCADA TO/TO/MP dispatch computer systems.

Examples of this type of data include, but are **not** limited to, the following:

1. Generator limits and unit control modes (UCMs);
2. Text messages;
3. Non-telemetered breaker and switching device status;
4. Calculated data including transfer limits and flows, interface limits and flows; and
5. Economic dispatch basepoints/desired generations, and AGC setpoints.

F. Telemetered Data Identification

NOTE

OP-18F is a confidential document subject to the ISO New England Information Policy. If access to OP-18F is needed, contact ISO Participant Support and Solutions as detailed on the ISO external website.

ISO, each LCC/SCADA TO, each TO and each MP shall uniquely and correctly identify the data being supplied to the network using the format described in OP-18 A for CNP sourced data and in OP-18F and OP-18G for ISO CFE data.

VII. METERING FOR POWER FACTOR MEASUREMENT PURPOSES

Each TO/MP shall submit to ISO the quantities necessary to calculate TO/MP lpf as prescribed in ISO New England Operating Procedure No. 17 - Load Power Factor and System Assessment (OP-17). A sufficient number of the necessary quantities shall be metered and recorded so that the resulting lpf is a valid calculation.

VIII. EQUIPMENT STANDARDS FOR NEW AND UPGRADED INSTALLATIONS

This section specifies standards for metering, recording and telemetering equipment that each TO/MP installs in all new and upgraded facilities. A TO/MP may maintain or repair existing equipment with like or improved components, but each TO/MP shall choose equipment that meets all the requirements of this OP and Section I.3.9 of the ISO Tariff when the equipment is being replaced for purposes other than maintenance or repair (i.e., for purposes of upgrading the facility).

A. ANSI Standards

All AC metering devices used shall conform to applicable American National Standard Institute (ANSI) C-12 standards as amended from time-to-time. HVdc metering devices shall meet or exceed the following accuracy requirements of ANSI standards as noted below in 1, 2, and 3.

1. Integrated metering quantities, such as watt-hours and the associated demand components shall conform to ANSI standard C12.
2. Instruments or transducers for the analog or digital measurement of telemetered quantities, such as MW, shall conform to ANSI standards C39.1, C39.5 and C37.90.
3. Instrument transformers shall conform to ANSI standard C57.13.

B. Specific ISO New England Standards

1. The design accuracy of individual components as well as overall systems shall conform to the standards contained in OP-18C.
2. Electro-mechanical Wh meters shall **not** be installed.
3. For all grounded wye system metering, three element meters and transducers shall be used. For all delta system (ungrounded) metering, two or three element meters and transducers may be used.
4. The requirement for data recorders and for integrated metering quantities shall be satisfied with the types of equipment listed below. Either type may be used internally or on interconnections with systems outside ISO.
    - A data recorder shall be installed at the metering location. Data shall be retrieved from recorders by on-site or remote interrogation. Where the TOs/MPs agree on the need for joint access to this recorded data, remote communications equipment is recommended to be installed
    - A multifunction meter shall be equipped with an interval data recorder capable of storing at least 60 days of interval data and an internal clock. Data shall be retrieved from the meter by remote interrogation. Where the TOs/MPs agree on a need for joint access to this recorded data, the meter program shall be secured appropriately.
    - The data recorder or multifunction meter equipped with an interval data recorder shall **not** be dependent on the alternating current (ac) voltage that it is metering as the sole power source if an alternative power source exists at the metering location (such as an ac station service emergency panel feed, a direct current (dc) battery or “street power”).
5. All data recorders shall be synchronized in time, within an accuracy of +/- 15 seconds, with the National Institute of Standards and Technology (NIST) periodically and when they are installed or returned to service after maintenance or repair.

6. Compensation for line and/or transformer losses, when used, shall be accomplished by using Level I or Level II metering accuracy standards as defined in OP-18 Section IV.B.7 of this OP.
7. DC metering associated with DC coupled Assets participating separately in any market shall be of equivalent accuracy and precision to AC meters meeting the ANSI C12 standard. Specifications for such devices shall be provided to the ISO and/or Host Participant upon request.

IX. REQUIREMENTS FOR DATA COMMUNICATIONS EQUIPMENT FOR TELEMETERING SYSTEMS

To ensure reliable data communications for telemetry, the telemetry equipment (RTU, Digital Metering, communication equipment etc.) located at and between stations [owned by an MP or Designated Entity (DE)], the LCCs or SCADA TOs and ISO, the following supporting telemetry data is required:

1. The equipment shall **not** be dependent on a single ac power source. The power source shall be a station battery or an uninterruptible power source capable of supporting the anticipated load for at least eight hours.
   - Communication only facilities (terminal or intermediate) shall have a battery rated for at least eight (8) hours and a suitable backup power source for extended periods.
   - This includes telephone company equipment co-located with MP or DE equipment.
   - "Communication facilities" noted above refer to all components (i.e.,: terminal and intermediate equipment, and communication media) along each path.
2. At stations where two battery systems are present, it is desirable that each of them be made capable of being a power source for the equipment.
3. The equipment shall be capable of operating in a temperature range of -20°C to +50 °C for equipment within the control building or -40 °C to +50 °C for equipment installed in other outdoor enclosures. This temperature range is based upon the conditions that could exist when the ac power source is lost and as a result, air conditioning or heating is lost.
4. The configuration/connection of communication circuits shall be designed so that a problem on one circuit does **not** cause a problem on another (i.e., the problem does **not** propagate). There shall be no single point of failure that leads to communication loss for more than one station.
5. Alarms shall be provided to the appropriate LCC or SCADA TO indicating the status of equipment covered by this section.

X. TESTING, CALIBRATION AND MAINTENANCE STANDARDS

A. Overall Requirements

Each TO/MP is responsible for properly maintaining its metering, recording and telemetering equipment in accordance with applicable ANSI standards as amended from time-to-time. The specific standards for testing, calibration and maintenance are put forth in this section. The accuracy standards to be observed are summarized in OP-18C.

B. Overall Telemetering System Test

Whenever transducers and/or telemetering systems are tested, an overall system test shall also be conducted. This system test includes the use of the calibrated transducers output as an input to the telemetry system. All receiving devices shall be verified against the applied input.

C. Telemetry Component Tests

To ensure the accuracy of telemetered data, each TO/MP shall do one of the following:

1. Use manual or computerized routines to check telemetered quantities (MW, MVAr & kV) against each other, revenue meter quantities and/or against derived values of an SE, to identify unreasonable values at least one day per calendar month as detailed in Section X.C.1.a of this OP. This option may only be used for equipment after the initial installation (or replacement) test where IX.C.2 (below) would apply for initial installation (or replacement).
   a. Each single day check shall include 24 data samples for each telemetered point, 1 for each hour of the day.
      - While individual hour samples may have variations that exceed tolerances, noted below, where six or more consecutive samples exceed the tolerance in 1-day appropriate calibration, repairs or replacement actions shall be taken.
      - Each sample may be from a single point in time within the hour or averaged/integrated over the hour interval.
      - Voltage variance, as compared against below tolerances, is each telemetered phase-phase voltage compared against at least one of the two below:
        - The SE resultant bus voltage associated with the telemetered voltage, given in, or corrected to, phase-phase

NOTE

Concerning average of telemetered voltages, when less than three voltages (of comparable phase relationship) are measured at the same substation bus, additional points of reference are needed for comparison. Other points of reference may include, but are **not** limited to, adjacent bus voltages, nearby scheduled voltages, or bus voltage in an SE.

        - The average of all non-zero telemetered voltages that are phase-phase on the same nominal voltage level at the substation. Busses at the same voltage level that are **not** tied shall be treated separately.
   b. The tolerances for acceptable MW, MVAr and kV telemetered quantities are as follows:
      - Watts: +/- 10 MW or +/- 4.5% of the largest fiducial value (whichever is smaller)
      - VArs: +/- 30 MVAr
      - Voltage: +/- 5 kV for 345 kV systems
        +/- 4 kV for 230 kV systems
        +/- 3 kV for 115 kV systems
        +/- 2 kV for 69 kV systems
        +/- 3% for systems below 69kV

c. The check above shall not be required for MVAr quantities if the MVAr quantities are measured from the same device that measures the telemetered MW quantities.
   - The purpose for this is that measurement drift of a device measuring both would cause errors in both MW and MVAr. Also, MVAr variances are often obscured by transformer losses or SE solutions that are **not** perfect.
   - With the bus-net method, MVAr quantities that originate from a different device than the associated MW telemetry would **not** be exempt from a MVAr bus-net even if the other telemetry on the bus had its MW and MVAr quantities measured from the same device.
   - If a MVAr bus-net is needed, VAr losses can be estimated based upon transformer test data to mitigate bus-net VAr error.

2. Calibrate or test the accuracy of transducers and telemetering systems according to manufacturer's procedures, on the following schedule:

Transducers:	at least once every six years
Analog Telemetry:	at least once every twelve months
Digital Telemetry:	at least once every six years

When tests are performed on transducers, errors shall **not** exceed accuracy limits stated in OP-18C. If during the test, errors exceed this value, the device shall be recalibrated, repaired or replaced as necessary to attain that accuracy.

Digital telemetry employing analog to digital converter(s) (ADC), the gain and offset characteristics of which are continuously monitored, and reported to SCADA, by ADC reference values that are within accuracy limits stated in OP-18C, shall be exempt from periodic calibration requirements. When accuracy limits stated in OP-18C are exceeded, the equipment shall be recalibrated, repaired or replaced as necessary to attain that accuracy. This digital telemetry test exemption may only be used for equipment after the initial installation (or replacement) accuracy test.

D. Watt-hour Meters

1. All Wh meters shall be tested by comparison to a solid-state Wh standard that is traceable to the NIST as outlined in Section X.F of this OP. Testing shall include an inspection, verification, and analysis of the metering system excluding instrument transformers.
2. HVDC Wh meters - dc Wh metering equipment using voltage inputs for current and voltage sensing shall conform to the following requirements. See Figure 9-1.
   a. DC test voltage source equipment for generating current and voltage inputs to the meter shall be traceable to NIST for accuracy.
   b. Voltmeters used for monitoring the input voltages to the dc meter during the test shall be traceable to NIST for accuracy.
   c. Meter nominal test voltage shall be the meter input voltage corresponding to the nominal operating voltage of the metered line.
   d. Meter "full load test amperes" shall be the meter input voltage corresponding to the nominal operating current of the metered line.
   e. The test points for the meter shall be as follows:
      - Full load test amperes

- 10% of full load test amperes
- 50% of full load test amperes
- 150% of full load test amperes

f. If meter pulse outputs are compared to calculated target values, and pulses from a standard, to determine meter accuracy, then worksheets detailing the test conditions and target pulse counts shall be made available prior to testing the meter. See Table 9-1, below.

g. If the meter is compensated to account for different operating modes of the metered circuit, then the meter shall be tested with compensation activated at each of the test points defined above. The operating modes that represent the normal operating conditions shall be tested as a part of periodic testing. All operating modes shall be tested upon commissioning.

h. For engineered (custom) metering systems, a hard copy of the current meter program shall accompany the meter test documentation.

i. If both revenue meter data and telemetry data are provided by the same meter, then provisions shall be made to continue the telemetry while the meter is out of the measurement circuit during the test.

j. If redundant meter schemes are used, then the generation of any alarms or status flags due to differences in measurement between the meters caused by the testing shall be documented. If redundant recorders are used, then differences in recorded pulse totals due to the testing shall also be documented.

k. If redundant meter schemes are used, then the start and stop time as well as the accumulated test energy for the meter under test shall be documented. In addition, the start and stop time as well as the accumulated energy during the test period shall be noted for the in-service meter.

l. A field standard meter that has been programmed identical to the meter under test may be used for certification provided that it meets the accuracy and certification requirements of Section IX.F of this OP.

Example Test Scheme for a DC Meter with Voltage Inputs.

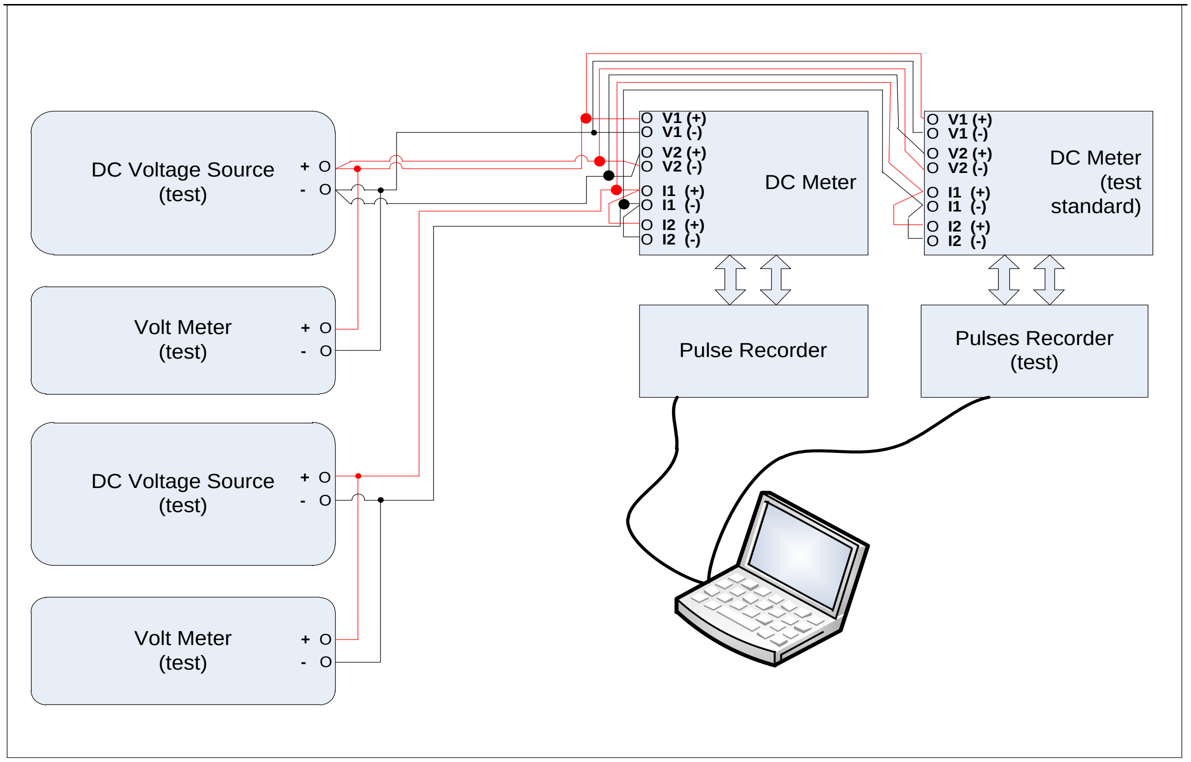

Figure 10-1

Example Pulse Target Worksheet

Test Conditions - Equation 1 (Import / South)		Uncompensated Reference Energy	Meter Reading	Meter Standard Reading	Meter error
Voltage	**Current**	**Pulses***	**Pulses***	**Pulses***	**(%)**
V1: 5V(450kV) V2:-5V(-450kV)	I1:0.5V(225A) I2:0.5V(225A)	506.25			
V1: 5V(450kV) V2:-5V(-450kV)	I1:2.222(1000A) I2:2.222(1000A)	1125			
V1: 5V(450kV) V2:-5V(-450kV)	I1:5V(2250A) I2:5V(2250A)	2531.25			
V1: 5V(450kV) V2:-5V(-450kV)	I1:7.5V(3375A) I2:7.5V(3375A)	3796.88			
* Pulses are 0.2 MWh / pulse. 225A (10%) test uses pulse over 30 min, all other test conditions use pulses for 15 min.					

Table 9-1

3. DC Wh metering for DC coupled Assets participating separately in any market shall conform to the following requirements:
   a. DC test voltage source equipment for generating current and voltage inputs to the meter shall be traceable to NIST for accuracy.
   b. Voltmeters used for monitoring the input voltages to the dc meter during the test shall be traceable to NIST for accuracy.
   c. Meter nominal test voltage shall be the meter input voltage corresponding to the DC voltage rating of the inverter.
   d. Meter "full load test amperes" shall be the meter input voltage corresponding to the DC ampere rating of the inverter.
   e. The test points for the meter shall be as follows:
      - Full load test amperes and nominal test voltage
      - Full load test amperes and 50% of nominal test voltage
      - 50% of full load test amperes and nominal test voltage
      - 50% of full load test amperes and 50% of nominal test voltage
   f. Where meter pulse outputs are compared to calculated target values, and pulses from a standard, to determine meter accuracy, worksheets detailing the test conditions and target pulse counts will be made available prior to testing the meter.
4. At a minimum, AC Wh meters shall be tested by one of the following two methods:
   a) Series test with external loads applied [permitted for testing either induction or solid-state Wh meters].
      i. "As-Found" series test performed at operating or nameplate voltage under the following three conditions:
         - Full load (FL) at the meter test ampere (TA) rating and unity power factor
         - Light load (LL) at 10% of the meter TA rating and unity power factor
         - Power factor (PF) at the meter TA rating and 0.5 power factor lag
      ii. The series test results shall be within the following accuracy limits:

Test Condition	Accuracy Limit
FL	+/- 0.2% error
LL	+/- 0.3% error
PF	+/- 0.5% error

      iii. The testing of any Wh meter with bi-directional functionality shall be tested for accuracy in both the forward (delivered) and reverse (received) directions for all Assets except those for Asset Related Demands (ARDs).
      iv. In addition to the "As-Found" series tests, all induction Wh meters shall have an "As-Found" individual element balance test performed. The individual elements shall be tested at operating or nameplate voltage, at FL test amps, and unity power factor. The individual element test results shall be within 1.0% of each other.

v. If the “As-Found” test results are outside the stated accuracy limits in section X.D.4.a.ii, then the meter shall be adjusted as closely as practical to 0.0% error or scheduled for replacement as soon as possible. The final “As-Left” test results shall be within the stated accuracy limits.

vi. Any induction Wh meter found outside of +/- 2.0% error (at any test condition) shall be adjusted and scheduled for replacement as soon as practical.

b) Single point three-phase test using the actual in-service load and meter uncompensated [**not** permitted for testing induction type Wh meters].

i. “As- Found" three-phase tested at actual in-service voltage, current, and power factor; provided that:

- voltage is within the range specified by the meter manufacturer
- current is within the meter's load range between light-load (LL) and class amps of the meter, and
- power factor is between unity and 0.5 lagging or leading

ii. The single point three-phase test results must be within the following accuracy limits:

Test Condition	Accuracy limit
Actual in-service load	+/- 0.2% error

iii. If the "As-Found" test results are outside the stated accuracy limits, then the meter shall be adjusted as closely as practical to a 0.0% error or promptly replaced. The final "As-Left" test results shall be within the stated accuracy limits.

iv. Any solid-state Wh meter found with accuracy tests outside the limits specified in section X.D.4.b.ii shall either be adjusted and scheduled for replacement as soon as practical; or, promptly replaced.

5. Meters with compensation for line and/or transformer losses shall be either one or the other of the following:

- Series tested with and without the compensation activated at the test points as defined in Section X.D.4.a of this OP; or
- Single point tested with compensation checked by comparison of compensated and uncompensated pulse data channels.

6. In-service testing of Wh meters shall be conducted with the frequency established in the local state utility control and distribution utility requirements for retail loads such as Asset Related Demands (ARDs). All other Assets, with noted exception, shall be tested with the following frequency: all Wh meters shall be tested at least once per calendar year, with the exception that non-induction type Wh meters, the operation of which is monitored daily, shall be tested at least once every six calendar years. Generator Assets that are not Settlement Only Resources and have a registered summer and winter claimed capability of less than 1 MW shall be tested with the frequency established in the local state utility control and distribution utility requirements for retail loads.

7. Periodic Energy Comparison

   a) Data recording equipment external to the meter shall be checked monthly by comparing a summation of the hourly demand readings with the kWh registered on the Wh meters for the same period of time. When only small quantities (less than 7,200 MWh in one month) have been registered, comparison is required every two months using two months of data. The difference in the sum of hourly demand readings and the kWh registered on the Wh meter shall be less than the value of the Wh meter transformer ratio multiplier. If this difference is greater, then the installation shall be reviewed and tested if the discrepancy is **not** explainable. This requirement is not applicable to DC meters for DC-coupled Assets participating separately in any market.

   b) For DRAs, data recording equipment external to the meter shall be checked at least annually by comparing a summation of the hourly demand readings with the kWh registered on the Wh meter for at least one month. If hourly data is available from the pulse source meter, then comparison shall take place at the hourly level.

8. The continuity of meter readings shall be maintained during tests either by use of a portable meter or other suitable methods. Note: use of the single point test method shall provide for continuity of both readings and data. A Wh meter test may be conducted during a period of **no** load or when the load is constant and the reading adjusted upon completion of the test. Pulse data shall also be adjusted upon completion of the test. If this is **not** practical, then other methods shall be used to segregate pulses registered due to the test from pulses based on registration of power flow.

E. Instrument Transformers

Scheduled tests of instrument transformers shall be conducted only if all other tests fail to explain a discrepancy. The testing procedure shall conform to the manufacturer's specifications and ANSI C57.13.

F. Test Equipment

Test equipment used in the calibration of instrument transformers or transducers shall be certified to values of accuracy and precision which are at least twice as accurate as the required accuracy of the equipment under test. Non-induction type Wh standards of 0.1% or better accuracy shall be used in the testing of Wh meters. All Wh standards shall be certified correct every twelve months.

NOTE

Traceability refers to relating individual measurement results to NIST measurement systems through an unbroken chain of comparisons.

All Wh standards shall be certified by comparison with laboratory standards whose accuracy is traceable to NIST. The standard certification values may be determined by the use of data obtained through round-robin procedures between TOs/MPs, provided that at least one of the laboratories maintains standards traceable to NIST. Standards used for the purpose of calibrating voltage and current transducers shall be of the same sensing type (e.g., Root Mean Square (RMS) or average) as the transducers under test. All telemetry standards shall be certified at least once every 24 calendar months.

The tests and calibrations shall be performed at ambient temperatures recommended by the manufacturers of the test equipment and the equipment under test.

Instrumentation used to check the tone modulating frequency for data transmission shall have a minimum definition of 0.001 Hertz. The dc ammeter or voltmeter used to measure input signals shall have a minimum accuracy of +/- 0.05%.

G. Record Keeping and Auditing

Each TO/MP shall maintain records of the testing, calibration and verification of all metering and telemetering equipment which is required to be installed pursuant to the provisions of this OP. The records shall include:

- Entity name
- Element (line, bus, transformer, etc.) name covered by telemetry
- Name of telemetering device (or system)
- The dates of testing, calibration or verification
- % error of as-found (and as-left if recalibrated or replaced)
- A note, if as-found is **not** within accuracy tolerance
- Action(s) taken (if applicable) including date(s) of action(s)

These records shall be retained for a minimum of the two most current testing (or verification) cycles or since the last audit (whichever is greater) and shall be available to ISO and the LCC upon request.

H. Notifications

When metering and telemetering equipment associated with TO/MP interconnections is scheduled for maintenance, test or upgrade, then interconnected TOs/MPs shall be notified at least two weeks in advance in order to have the opportunity to participate in or witness the maintenance, test or upgrade.

XI. SECURITY OF METERED AND RECORDED DATA

Security shall be addressed to prevent unlawful, unintentional or unauthorized access to those portions of the firmware, software and data being collected that would have an effect on the metered and recorded quantities.

XII. COMPLIANCE

Periodically, ISO may conduct an audit survey of metering, recording devices and telemetering criteria to determine the degree of TO/MP compliance with all OP-18 requirements.

OP-18 Revision History

Document History (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

Rev. No.	Date	Reason
- -	05/16/22	For previous revision history, refer to Rev 20 available through Ask ISO;
Rev 20.1	08/17/20	Typo correction: Rev 20 effective date of August 7, 2020 missing in body of text in Section II.A.3
Rev 20.2	11/23/21	Periodic review performed requiring no intent changes; Made ministerial administrative changes required to publish a Minor Revision;
Rev 21	05/16/22	Biennial review performed by procedure owner; Truncated revision history per business process in SOP-RTMKTS.0210.0010; Section V edits for ATRR criteria clarification
Rev 22	08/16/23	Periodic review performed by procedure owner; Added Section II Acronyms and Definitions, moved definitions from old Section XII to new Section II and deleted old Section XII; Updated new Section VI to clarify requirements for SCADA Servers and LCC control center configurations based on current practices and reliability improvements.
Rev 22.1	09/28/23	Minor formatting changes.