

**METERING PROTOCOL**

**APPENDICES A-G**

**APPENDIX A**

**FAILURE OF ISO FACILITIES**

**A 1 WEnet Unavailable**

**A 1.1 Unavailable Functions of WEnet**

During a total disruption of the WEnet the ISO will not be able to:

- (a) communicate with ISO Metered Entities or SCs to acquire or provide any Meter Data or Settlement Quality Meter Data; and
- (b) communicate general information.

**A 1.2 Communications during WEnet Unavailability**

During any period of WEnet unavailability, the ISO shall:

- (a) make all reasonable efforts to provide general information to ISO Metered Entities and SCs using voice communications; and
- (b) inform ISO Metered Entities and SCs of the methods they must use to provide Meter Data and Settlement Quality Meter Data to the ISO during that period.

**A 2 Primary MDAS Master Station Completely Unavailable**

**A 2.1 Notification of Loss of Primary MDAS Master Station**

In the event that the primary MDAS master station becomes completely unavailable, the ISO will use alternate communications to notify the redundant MDAS master station that the primary MDAS master station is unavailable. The ISO will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

**A 2.2 Notification of Restoration of Primary MDAS Master Station**

The ISO will post confirmation on WEnet that all computer systems are functioning normally (if such be the case) and use the redundant MDAS master station to take complete control of the all MDAS functions. Once the primary MDAS master station is again available, all functions will be transferred back to the primary MDAS master station and the ISO will notify all ISO Metered Entities and SCs via the WEnet.

**APPENDIX B**

**CERTIFICATION PROCESS FOR METERING FACILITIES**

Paragraphs B1 to B3 of this Appendix describe the steps that ISO Authorized Inspectors and the ISO will take to certify Metering Facilities of ISO Metered Entities.

The steps described here will also be applicable to SC Metered Entities where no certification requirements are imposed on a SC Metered Entity by its Local Regulatory Authority.

Paragraph B5 of this Appendix describes the manner in which requests must be made to the ISO to perform the certification of Metering Facilities.

**B 1                    Documentation to be Provided by ISO/SC Metered Entity**

The ISO Metered Entity or SC Metered Entity shall provide the ISO and the ISO Authorized Inspector with schematic drawings (both detailed and one line) of the Metering Facilities being considered for ISO certification. Such drawings shall be dated, bear the current drawing revision number and show all wiring, connections and devices in the circuits. Drawings shall also be provided for instrument transformers to the meter and the meter to the WEnet POP.

In addition, the ISO Metered Entity or SC Metered Entity will provide the ISO and the ISO Authorized Inspector with a completed ISO Meter Certification Form (a copy of which forms part of this Appendix) in respect of each set of Metering Facilities being considered for ISO certification.

**B 2                    Documentation to be completed by the ISO Authorized Inspector**

The ISO Authorized Inspector will complete an ISO approved site verification form (an internal ISO document) in relation to each set of Metering Facilities that it inspects. The site verification form and the ISO Meter Certification Form will be the official forms used to document whether Metering Facilities meet the ISO certification criteria.

If there are any discrepancies between the ISO certified drawings on file and the actual metering circuitry inspected by the ISO Authorized Inspector or the ISO, then the ISO Authorized Inspector or the ISO will document that discrepancy and revise the schematic drawings provided to the ISO. The ISO Authorized Inspector will notify the ISO of the discrepancy and give the ISO Metered Entity or SC Metered

Entity a notice detailing the discrepancies within 24 hours of that notification.

**B 3                    Review by the ISO**

The ISO will review all documentation provided to it by the ISO Metered Entity or SC Metered Entity (including the ISO Meter Certification Form) and the site verification form prepared by the ISO Authorized Inspector.

If the ISO finds that the data is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Protocol, the ISO shall provide written notice of the deficiencies to the ISO Metered Entity or SC Metered Entity within seven days of receiving the documentation referred to above.

If the ISO finds that the data is complete, it shall, subject to any exemptions granted under MP 13.5.1 in relation to providing Meter Data directly to MDAS, initiate tests to certify the MDAS interface with the relevant Metering Facilities.

Upon successful completion of the MDAS interface tests the ISO will issue a Certificate of Compliance. The ISO shall return the original schematic drawings, stamped by the ISO as approved and certified, and the original ISO Meter Certification Form and site verification form. The ISO will retain copies of these documents. Once all conditions have been satisfied to the ISO's satisfaction, the ISO shall promptly issue an original Certificate of Compliance.

**B 4                    Provisional Certification**

If the ISO finds that:

- (a) the data provided to it by the ISO Metered Entity or SC Metered Entity is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Protocol; or
- (b) the Metering Facilities fail the MDAS interface test,

the ISO may, at its discretion, elect to issue a provisional Certificate of Compliance in respect of those Metering Facilities. The term of and conditions on which such a provisional Certificate of Compliance is issued shall be at the ISO's discretion. However, the ISO will not issue an original Certificate of Compliance to the ISO Metered Entity until such time as all of the conditions of the provisional Certificate of Compliance have been fulfilled to the satisfaction of the ISO.

**B 5                    Requests for the ISO to Perform Certification**

If an ISO Metered Entity would like the ISO to perform the certification of its Metering Facilities in accordance with MP 3.1.3, that ISO Metered

Entity shall submit a written request to the ISO. The written request must:

- (a) specify the Metering Facilities to be certified;
- (b) provide the documentation referred to in paragraph B1 of this Appendix; and
- (c) detail the reasons why it would be impossible or impractical for the ISO Metered Entity to engage the services of an ISO Authorized Inspector to perform the certification.

The ISO will, within 14 days of receiving a request for it to certify Metering Facilities, inform the ISO Metered Entity whether it will undertake the certification or require the ISO Metered Entity to engage an ISO Authorized Inspector to perform the certification.

<b>ISO Meter Certification Form</b>							
<b>Facility Information</b>							
Name:				Unit Name:			
Address:				Drawing Numbers: <span style="float: right; font-size: small;">(see note 1)</span>			
ISO Metered Entity Contact :				Phone Number:			
Scheduled ISO Inspection Date:							
<b>Generator Information</b>							
Gross Output			Auxiliary Load				
Net Output			Voltage / Connections				
<b>Revenue Billing Information</b>							
Meter Manufacturer			Register Constant				
Meter Serial Number			Program ID Number				
Meter Type			Device ID				
Meter Form			IP Address/Router Port #				
Does meter have external pulse inputs for totalization purposes? Yes <input type="checkbox"/> (info. is attached) No <input type="checkbox"/>							
<b>Internal Mass Memory Constants</b>							
Function	Channel	$K_e$	PRI KWH Constant	Interval Size	Display Sequence		
KWH DELIVERED							
KVARH DEL							
KVARH REC							
KWH RECEIVED							
<b>Voltage Transformer Information</b>				<b>Current Transformer Information</b>			
Name Plate	$A_\phi$	$B_\phi$	$C_\phi$	Name Plate	$A_\phi$	$B_\phi$	$C_\phi$
Manufacturer				Manufacturer			
Serial Number				Serial Number			
Type				Type			
Ratio				Ratio			
Voltage Class:				Voltage Class			
BIL Rating				BIL Rating			
Accuracy Class				Accuracy Class			
Burden Rating				Rating Factor			
Connected Burden				Burden Rating			
				Connected Burden			
				Applied Test Burden			
				Burden Test	Pass <input type="checkbox"/> Fail <input type="checkbox"/>	Pass <input type="checkbox"/> Fail <input type="checkbox"/>	Pass <input type="checkbox"/> Fail <input type="checkbox"/>
<b>Instrument Transformer Correction Factors (FCF)</b> <span style="float: right; font-size: small;">(see note 2)</span>							
<b>Full Load</b>			<b>Power Factor</b>			<b>Light Load</b>	
<b>Line Loss Compensation Values (at Full Load Meter Rating)</b> <span style="float: right; font-size: small;">(see note 2 and 3)</span>							
% Watt Fe Loss				% Var Fe Loss			
% Watt Cu Loss				% Var Cu Loss			
<b>Total Compensation Values (at Full Load Meter Rating)</b>							
% Watt Total Loss				% Var Total Loss			
Completed by:						Date:	
Remarks:							

Reviewed by:	Date:
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Notes:

1. ISO Metered Entities shall provide a copy of the one line diagram and schematics detailing the connections from the instrument transformer to the meter, communication circuit and local meter data server (if applicable) in accordance with this Appendix.
2. ISO Metered Entities shall attach a copy of the calculations used to determine these values.
3. For Power Transformer Loss Correction and Radial Line Loss Correction values the appropriate sign (+/-) should be utilized depending on the flow of Energy (delivered/received) and the location of the ISO Meter Point.

**APPENDIX C**

**METER CONFIGURATION CRITERIA**

**C 1 Power Flow Conventions**

Meters shall be installed and configured in such a manner so as to define the 4 Quadrants referred to in Exhibit 1 to Appendix D of this Protocol.

**C 2 ISO Standard Meter Memory Channel Assignments**

Metering Facilities shall be installed and configured in such a manner so as to comply with the following ISO requirements:

- Channel 1 shall record active power delivered by the ISO Controlled Grid;
- Channel 2 shall record reactive power delivered by the ISO Controlled Grid;
- Channel 3 shall record reactive power received by the ISO Controlled Grid; and
- Channel 4 shall record active power received by the ISO Controlled Grid.

For metering with bi-directional power flows, the ISO reserves the right to require metering which will measure 4 quadrant Vars. Situations like a generating plant that nets gross generator output and auxiliary loads on one meter which could swap from a supplying to a buying mode and vice versa may require this type of metering. To properly account for such cases, six channels of data will be required. This configuration is considered optional unless specified by ISO as required. Such Metering Facilities shall be installed and configured in such a manner so as to comply with the following ISO requirements:

- Channel 1 shall record active power delivered by the ISO Controlled Grid;
- Channel 2 shall record quadrant 1 reactive power delivered by the ISO Controlled Grid;
- Channel 3 shall record quadrant 3 reactive power received by the ISO Controlled Grid;
- Channel 4 shall record active power received by the ISO Controlled Grid;



- Channel 5 shall record quadrant 2 reactive power delivered by the ISO Controlled Grid; and
- Channel 6 shall record quadrant 4 reactive power received by the ISO Controlled Grid.

**C 3 ISO Standard Meter Display Modes**

The following display readings shall be displayed in the normal display mode to comply with ISO requirements.

**Normal Display Mode (Standard Configuration, Uni-directional/Bi-directional kWh and kVarh)**

For standard metering applications the display items should be utilized in the sequence listed below. When metering uni-directional power flows, the quantities listed below that do not apply (i.e. for generation only applications, the delivered quantities should have zero accumulation) may be omitted. The only exception to this would be where the display items correlate to the load profile channel assignments. The 4 display readings that correlate to the 4 load profile channels must also be displayed.

- Date MM:DD:YY.
- Time HH:MM:SS (Pacific Standard Time, military format).
- Total kWh delivered by the ISO Controlled Grid.
- Maximum kWd (5 minute or hourly demand interval) delivered by the ISO Controlled Grid.
- Date and time of maximum kWd delivered by the ISO Controlled Grid.
- Total kVarh delivered by the ISO Controlled Grid.
- Total kVarh received by the ISO Controlled Grid.
- Total kWh received by the ISO Controlled Grid.
- Maximum kWd (5 minute or hourly demand interval) received by the ISO Controlled Grid.
- Date and time of maximum kWd received by the ISO Controlled Grid.

**Normal Display Mode (Optional Configuration, Bi-directional Kwh and Four Quadrant kVarh)**

For metering bi-directional power flows in which ISO requires optional 4 quadrant Var measurement, the following display items should be displayed in the sequence listed below:

- Date MM:DD:YY.

- Time HH:MM:SS (Pacific Standard time, military format).
- Total kWh delivered by the ISO Controlled Grid.
- Maximum kWd (5 minute or hourly demand interval) delivered by the ISO Controlled Grid.
- Date and time of maximum kWd delivered by the ISO Controlled Grid.
- Total kVarh for Quadrant 1.
- Total kVarh for Quadrant 2.
- Total kVarh for Quadrant 3.
- Total kVarh for Quadrant 4.
- Total kWh received by the ISO Controlled Grid.
- Maximum kWd (5 minute or hourly demand interval) received by the ISO Controlled Grid.
- Date and time of maximum kWd received by the ISO Controlled Grid.

#### **Consumption Values**

The consumption values shall be in XXXXX.X format and demand in XXXX.XX format. The register scaling factor should be set such that the display does not roll over in less than 60 days.

#### **Alternative Display Mode**

The values listed below should be displayed in the alternate display mode to comply with ISO requirements:

- Phase A voltage magnitude and phase angle.
- Phase B voltage magnitude and phase angle.
- Phase C voltage magnitude and phase angle.
- Phase A current magnitude and phase angle.
- Phase B current magnitude and phase angle.
- Phase C current magnitude and phase angle.
- Neutral current magnitude and phase angle (if available).
- Instantaneous kW delivered by the ISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is out of ISO Controlled Grid).
- Instantaneous kW received by the ISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is received by the ISO Controlled Grid).

When available, the alternative display mode may also be used by ISO Metered Entities to display other definable quantities in sequence after the values defined above.

**C 4 Instantaneous Power Factor - Test Mode**

The following values should be displayed in the test mode to comply with ISO requirements:

- total pulse count for test; and
- total consumption during test.

During the test mode the above values should be provided for each function being tested (Watts, Vars). The data displayed by the meter while in test mode shall not change the normal mode display registers nor shall it be recorded in the load profile channels. This requirement is imposed to prevent the test data from being recorded as actual load/generation data.

ISO Metered Entities may add additional display quantities in sequence in the test mode after the values defined above.

**C 5 Transformer and Line Loss Correction**

The ISO Metered Entity will be responsible for properly calculating and applying the transformer and line loss corrections to its meters in accordance with this Protocol to reflect the actual meter usage (on the low side) as opposed to the theoretical meter usage at the transmission point.

**C 6 CT/VT and Cable Loss Correction Factors**

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet the minimum ISO accuracy requirements, then one of the actions listed below must to be taken:

- (a) replace the instrument transformer(s) with higher burden rated revenue class units; or
- (b) reduce the burden on the circuit to comply with the name plate of existing instrument transformer(s); or
- (c) apply correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The ISO preferred action is that referred to in paragraph (a) above.

The ISO Metered Entity will be responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meters in

accordance with this Protocol to adjust for inaccuracies in the metering circuit.

**C 7**

**Special Applications, Configurations and Unique Situations**

ISO Metered Entities are responsible for providing the ISO with the necessary Meter Data and other information to enable the ISO to prepare Settlement Quality Meter Data. For instance, where there is a generating plant with multiple generators and auxiliary loads, the ISO Metered Entity must provide appropriate information (i.e. documentation, descriptions, one line diagrams, etc.) to the ISO to ensure that the ISO can properly account for the net generator output of each unit under all combinations of generation and load (e.g. where only one generator is operating but all auxiliary loads are being supplied).

## **APPENDIX D**

### **STANDARDS FOR METERING FACILITIES**

The standards for Metering Facilities referred to in this Appendix provide additional details to the standards referred to in Appendix J to the ISO Tariff.

The standards referred to in Appendix J to the ISO Tariff and this Appendix apply to ISO Metered Entities and, where the relevant Local Regulatory Authority has not set any standards, to SC Metered Entities.

#### **D 1 Standards for Existing Metering Facilities**

Existing Metering Facilities are those facilities that are fully installed as of the ISO Operations Date. Existing Metering Facilities used by ISO Metered Entities shall meet the following general standards:

- revenue quality instrument transformers at the generator output level (specifically at all main generators, banks and local distribution load supplied from the generator) must have an accuracy of 0.3% or better
- generator auxiliary load metering must have an overall accuracy of 3%
- revenue quality instrument transformers at transmission metering points must have an accuracy of 0.3% or better

#### **D 2 General Standards for New Meters**

New Meters are those meters that are installed after the ISO Operations Date. New Meters used by ISO Metered Entities shall meet the following general standards:

- they must be revenue quality in an accuracy class of 0.25%
- they must be remotely accessible, reliable, 60 Hz, three phase, bi-directional, programmable and multifunction electronic meters
- they must be capable of measuring kWh and kVarh and providing calculated three phase values for kVah, kVa
- they must have a demand function including cumulative, rolling, block interval demand calculation and maximum demand peaks
- there must be battery back-up for maintaining RAM and a real-time clock during outages of up to thirty days

- there must be AC potential indicators on each of the three phases
- they must be capable of being powered either internally from the bus or externally from a standard 120 volt AC source.
- they must be capable of providing MDAS (MV-90) addressable metering protocol
- they must be capable of 60 days storage of kWh and KVarh interval data

If there is any inconsistency between these general standards and the detailed standards referred to in paragraphs D3 and D4 of this Appendix, the detailed standards shall prevail.

**D 3 Detailed Standards for New Meters**

Exhibit 1 to this Appendix provides the detailed specifications with which new meters must comply.

**D 4 Detailed Standards for New Oil Filled, Wound Instrument Transformers**

Exhibit 2 to this Appendix provides the detailed specifications with which new oil filled, wound instrument transformers must comply.

**D 5 Standards for Compatible Meter Data Servers**

In order for a meter data acquisition and processing system of a metered entity to be certified by the ISO as a Compatible Meter Data Server, that metered entity must satisfy the ISO that the server is capable of providing:

- Meter Data and/or Settlement Quality Meter Data to MDAS in the Meter Data Exchange Format via WEnet and/or REMnet via File Transfer Protocol (FTP);
- Meter Data to the ISO which is real data at least comparable to data obtained directly by MDAS from meters;
- Meter Data and/or Settlement Quality Meter Data to the ISO on demand within 10 minutes of receiving such a demand from the ISO;
- System Back Up procedures that permit submission of data within 41 days of a Trading Day to MDAS even in the event of a major facility or system problem. Back Up procedures must be documented and available for review by ISO.

- System Security procedures that limit the accessibility to meter data and the system parameters . The System Security procedures must be documented and available for review by ISO.
- If applicable, procedures that define methods of profiling consumption meter data into intervals. These procedures must be documented, they must follow any appropriate regulatory guidelines and they must be available for review by the ISO.
- System day-to-day operational procedures, these procedures should be available for ISO review and audit.

**EXHIBIT 1 TO APPENDIX D**

**SPECIFICATION MTR1-96**

**ENGINEERING SPECIFICATION  
FOR POLYPHASE SOLID-STATE  
ELECTRICITY REVENUE QUALITY METERS  
FOR USE ON THE ISO CONTROLLED GRID**



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**1 General Information**

This Exhibit applies to all solid-state polyphase electricity meters used in revenue metering applications on the ISO Controlled Grid (Meters).

**2 Scope**

**2.1 General**

This Exhibit provides the minimum functional and performance requirements for Meters. All requirements in this Exhibit are intended to ensure the expected life cycles, security, accuracy, reliability and minimum maintenance requirement of Meters. Some requirements, however, are specified to maintain the compatibility and interchangeability of the Meter.

**2.2 Applicability**

Meters approved under this Exhibit may not be required to have all of the specified features. Meters shall meet the specified minimum requirements and the requirements of Section 13 (Meter Approval Testing) of this Exhibit.

**3 Metering Functions**

**3.1 Measured Quantities**

As used in this Exhibit, the term "delivered" applies to Energy flowing out of the ISO Controlled Grid and the term "received" applies to Energy flowing into the ISO Controlled Grid.

**3.1.1 Consumption**

The following consumption quantities are required for all Meters approved for use on the ISO Controlled Grid:

- (a) Kilowatt-hours—delivered;
- (b) Kilowatt-hours—received;
- (c) Kilovar-hours—delivered, received, for each quadrant;
- (d) Kilovoltamp-hours—delivered, received, for each quadrant;
- (e) Ampere-squared-hours; and
- (f) Volts-squared-hours.

**3.1.2 Demand**

The following demand quantities are required for all meters approved for use on the ISO Controlled Grid:

- (a) Kilowatts—delivered;

- (b) Kilowatts—received;
- (c) Kilovars—delivered, received, for any quadrant; and
- (d) Kilovoltamps—delivered, received, for any quadrant.

### **3.1.3 Power Factors**

The ISO may specify average power factors for the previous demand sub-interval in any quadrant or any combination of two quadrants.

### **3.1.4 Reverse Consumption/Demand**

The Meter shall be programmable to take one of the following actions for reverse consumption and demand quantities:

- (a) ignore the reverse quantities; and
- (b) add the reverse quantities to the appropriate consumption and demand quantities.

### **3.2 Basic Default Metering Function**

When power is applied to the Meter, it shall immediately begin recording bi-directional total kilowatt-hours. Reverse power flow shall carry a negative sign. This function shall be performed regardless of whether the Meter is programmed or not and shall not require a battery. An unprogrammed Meter shall indicate that it is unprogrammed. The ISO may request a Meter to be programmed with a specific program.

### **3.3 Demand Metering Function**

Meters shall have the following demand metering functions:

- (a) as a minimum, the Meter shall be programmable for fixed and/or rolling interval demand calculations on bi-directional kilowatts and kilovars;
- (b) a battery shall not be required to perform demand calculations, to save the results or to communicate the results to a handheld meter reader connected to the optical port;
- (c) the Meter shall be programmable for one minute delivered kilowatt demand (as an approximation of “instantaneous” kilowatts delivered) in addition to the rolling interval demand calculation. The one minute demand is not required to be synchronous with the other demand quantities;
- (d) the Meter shall be programmable for rolling interval demand calculations for any optional demand quantity (see Section 3.1.2) that ISO specifies.
- (e) demand intervals shall be programmable for a duration of 5, 10, 15, 30 or 60 minutes;



- (f) the demand interval shall be composed of an integral number of sub-intervals. Sub-interval duration shall be a programmable duration of 1, 5, 10, 15 or 30 minutes;
- (g) demand functions shall be capable of temporary suspension for a programmable time interval after power is restored following a power outage. The length of time shall be programmable from zero to 60 minutes in one minute intervals;
- (h) after a demand reset, further manual demand resets shall be prevented with a programmable lockout time. A demand reset from a Meter Programmer connected to the optical port is not subject to this delay and can be initiated as frequently as required; and
- (i) if the Meter has been programmed for Time-of-Use (TOU) functions, the time at which maximum demand occurred shall be recorded at the end of that demand interval.

#### **3.4 Time-of-Use (TOU) Metering Function**

Meters shall have the following TOU metering functions:

- (a) as a minimum, the Meter shall be programmable for TOU calculations for bi-directional kilowatt-hours and kilovarhours and bi-directional kilowatt and kilovar demand.;
- (b) the Meter shall be programmable for TOU calculations for any optional consumption or demand quantity (see Section 3.1.1 or 3.1.2) that the ISO specifies;
- (c) the calendar shall be programmable into one to four mutually exclusive seasons;
- (d) each season shall be further programmable into one to four mutually exclusive daily TOU schedules;
- (e) the Meter shall be capable of distinguishing weekdays, weekends, days of the week, and holidays.
- (f) each consumption and demand quantity shall be metered independently for each TOU schedule;
- (g) only one season and one TOU schedule shall be active at a given time. There shall always be one active season and one active TOU schedule;
- (h) each daily TOU schedule shall be capable of a minimum of eight switch points with a minimum resolution of a quarter hour;
- (i) the calendar shall be capable of accommodating leap years, daylight saving time changes and recurring holidays; and
- (j) the Meter shall have capacity for a minimum calendar of 20 years, taking into account 12 holidays/year, 4 seasons/year, and 2 daylight savings time adjustments/year.

### **3.5 Self-Read TOU Metering Function**

Meters shall have the following self-read TOU metering functions:

- (a) as a minimum the Meter shall perform a self-read of all consumption and demand quantities on season changes. A self-read shall consist of reading the quantities, resetting the demand and storing the data;
- (b) the change of season self-reads shall occur at midnight of the day before the season change;
- (c) the ISO may specify that the Meter be programmable for up to three consecutive self-reads. The self-reads shall be programmable for:
  - i. a specific day of each month at midnight;
  - ii. a specific number of days from the last demand reset (read) at midnight; and
  - iii. self-read time of use metering; and
- (d) self-read data, other than previous season data, need not be displayed but shall be retrievable with a Meter Programmer connected to the optical port.

### **3.6 Load Profile Function**

Meters shall have the following load profile functions:

- (a) the ISO may specify that the Meter provide load profile recording of interval data for 1 to 4 channels of consumption quantities;
- (b) load recording of interval data shall operate independently of the TOU functions;

- (c) date and time shall be stored with the load recording of interval data;
- (d) load recording of interval data shall use a "wraparound" memory that stores new interval data by writing over the oldest interval data;
- (e) the load recording of interval data function shall be capable of storing and communicating a minimum of 60 days of 4 channel, 5 minute interval data, in addition to allowances for event recording (power outages, resets, time sets, etc.);
- (f) the load recording of interval data function shall have the capacity to count and store at least 16,000 counts in a 15 minute period of time; and
- (g) load recording of interval data shall continue while the Meter is communicating with a Meter Programmer connected to the optical port.

### **3.7 Function during Power Disturbances**

Meters shall have the following functions during power disturbances:

- (a) during powerline disturbances such as brownout or outage conditions the Meter shall maintain all meter data as well as time keeping functions. Display and communication functions are not required during these conditions;
- (b) the Meter shall withstand the following outages during a continuous ten year or longer service without the need to maintain its auxiliary power system, including replacing the battery:
  - i. 20 short outages per year of less than 30 seconds per outage; and
  - ii. 40 days of continuous/cumulative outage;
- (c) during a power outage, critical program and billing data shall be written to non-volatile memory. When power is restored, data shall be returned to active memory and data collection resumed;
- (d) following a power outage, register "catch-up" time shall be a maximum of 30 seconds. During the "catch-up" time the Meter shall still calculate consumption and demand quantities. Optional outputs shall also function during this time;
- (e) during power outages, time shall be maintained with a cumulative error of no more than 2 minutes per week (0.02%);
- (f) the Meter shall record the date and time of any power outage; and

- (g) Meters may also record the duration of any power outage.

### **3.8 Meter Test Mode Function**

Meters shall have the following meter test mode functions:

- (a) the Meter shall have the capability of a Test Mode function that suspends normal metering operation during testing so that additional consumption and demand from the tests are not added to the Meter's totals;
- (b) the Test Mode function shall be activated by a permanently mounted physical device that requires removal of the Meter cover to access or by a Meter Programmer connected to the optical port;
- (c) activation of the Test Mode shall cause all present critical billing data to be stored in non-volatile memory and restored at the time of exit from the Test Mode;
- (d) upon activation of the Test Mode, register displays shall accumulate beginning from zero;
- (e) actuation of the billing period reset device during Test Mode shall reset the test mode registers;
- (f) after a programmable time-out period, the Meter will automatically exit from Test Mode and return to normal metering; and
- (g) the default Test Mode registers for an unprogrammed meter shall include as a minimum:
- i. time remaining in the test interval;
  - ii. maximum kilowatt block demand; and
  - iii. total kilowatt-hours.

## **4 Display Requirements**

### **4.1 LCD Display**

The Meter shall have an electronic display for displaying the consumption and demand quantities. A liquid crystal display (LCD) is preferred.

### **4.2 Viewing Characteristics**

Digits for displaying the consumption and demand quantities shall be a minimum of  $7/16$ " in height and be legible in normal daylight conditions from a distance of six feet by an observer. The viewing angle shall be a minimum of fifteen degrees from the front Meter face line of sight.

#### **4.3 Display Components**

The display shall provide the following:

- (a) six digits for display of the consumption and demand quantities and constants with decimal points for the three least significant digits;
- (b) three digits for numeric display identifiers (ID numbers);
- (c) alternate and Test Mode indication;
- (d) potential indication for each phase;
- (e) current TOU rate indicator;
- (f) end of interval indicator;
- (g) visual representation of the magnitude and direction of kilowatt loading;
- (h) visual representation of the magnitude and direction of kilovar loading if the Meter is capable of measuring kilovars; and
- (i) Annunciators for most consumption and demand quantities.

#### **4.4 Digits**

Consumption and demand quantities shall be programmable for display with leading zeroes in four, five or six digits with a decimal point at any of the least significant three digits.

#### **4.5 Time Format**

Time shall be displayed in the 24 hour military format.

#### **4.6 Date Format**

Date shall be displayed programmable in either Day/Month/Year or Month/Day/Year format.

#### **4.7 Operating Modes**

The display shall have at least three of the following operating modes:

- (a) Normal Mode – in this mode, the display shall scroll automatically through the programmed displays for normal meter reading;
- (b) Alternate Mode – in this mode, the display shall scroll automatically, scroll manually or freeze for up to one minute for alternate programmed displays;
- (c) Test Mode – in this mode, the display shall scroll automatically, scroll manually or freeze for up to one minute for test quantity displays; and
- (d) Segment Check – in this mode, all segments or displays are activated to verify display integrity.

Display ID numbers and display sequence shall be independently programmable for each of the modes referred to above. Display times shall be programmable.

**4.8 Normal Mode**

Upon power-up, the Meter display shall operate in the Normal Mode. The Meter display shall operate in Normal Mode until power is disconnected or until either the Alternate Mode or the Test Mode is activated.

**4.9 Alternate Mode**

The Alternate Mode shall be initiated with a display control device that does not require Meter cover removal or with a Meter Programmer connected to the optical port.

**Display Items**

As a minimum, the Meter shall provide the display quantities and items for each of the modes referred to in Section 4.7 as detailed in Attachment 2.

**4.10 Constants and Correction Factors.**

The Meter shall have programmable multi-variable polynomial function multipliers and/or summers to account for instrument transformer ratios, instrument transformer correction factors, the Meter constant, radial line losses and power transformer loss correction.

**4.11 Identifiers**

The Meter shall have programmable identifiers for the Meter ID, the person who programmed the Meter (programmer ID) and the current program ID. The Meter ID shall be capable of eight alphanumeric characters.

## **5 Meter Diagnostics**

### **5.1 Self-test**

The Meter register shall be capable of performing a self-test of the register software. As a minimum, the self-test shall be performed at the following times:

- (a) whenever communications are established to the register;
- (b) after a power-up; and
- (c) once per day.

### **5.2 Diagnostic Checks**

As a minimum, the following diagnostic checks shall be performed during a self-test:

- (a) check the backup battery capacity;
- (b) verify the program integrity; and
- (c) verify the memory integrity.

### **5.3 Pulse Overrun**

The register shall be capable of detecting that the maximum number of pulses have been exceeded during a demand interval.

### **5.4 Error and Warning Displays**

Meters shall be capable of the following displays:

- (a) any detected error or warning shall be stored in memory and an error or warning code displayed on the display;
- (b) error code displays shall freeze the display; and
- (c) warning code displays shall be programmable to one of the following choices:
  - i. freeze the warning code on the display;
  - ii. ignore the warning code (not displayed); or
  - iii. warning code display at the end of the Normal, Alternate or Test Modes display sequences.

**5.5 Error Reset**

Error or warning conditions shall only be reset upon an explicit command invoked via the Meter Programmer or upon some other explicit action by the Meter technician.

**6 Programming and Software**

**6.1 Optical Communications Interface.**

The Meter shall be capable of communicating with a handheld reader (Itron DataCap or similar) through the optical port.

**6.2 Meter Programmers**

The ISO and ISO Authorized Inspectors will use PC DOS based laptop and handheld computers with LCD displays as meter reader/programming devices (Meter Programmers). Communications with the Meter shall be through the optical port.

**6.3 Software**

The ISO Metered Entity shall ensure that its supplier provides all software for maintenance, programming and operation of the Meter. The software shall include the following:

- (a) Rate Development Program;
- (b) Field Program;
- (c) Field Disk Serialization Program; and
- (d) Password protection to preclude 3rd party access for all levels of access except read-only.

**6.4 Rate Development Program**

The ISO Metered Entity shall ensure that its supplier provides a Rate Development Program software package which allows the ISO to customize the Meter's rate schedules and the Meter's operating parameters. The Rate Development Program shall be capable of utilizing all programmable functions of the Meter.

**6.5 Rate Development Program Functions**

The Rate Development Program as a minimum shall provide the following functions in a "user-friendly" manner:



- (a) originate or modify Meter configuration records;
- (b) validate user entries for format and range;
- (c) translate user entry into code for configuring the Meter;
- (d) send and receive configurations to and from the Meter;
- (e) compare configuration files from the Meter with desired files and report discrepancies;
- (f) read Meter billing data and load profile data;
- (g) generate Meter data and diagnostic reports for printing; and
- (h) generate configuration files for loading into the Meter via the Field Program.

#### **6.6 Field Program**

The ISO Metered Entity shall ensure its supplier provides a Field Program software package for use with ISO's Meter Programmer. The Field Program in conjunction with any such Meter Programmer shall be capable of loading the rate schedule and meter operating parameters as generated by the Rate Development Program into the Meter.

#### **6.7 Field Program Functions**

The Field Program as a minimum shall provide the following functions:

- (a) set date and time on the Meter;
- (b) preset the Meter consumption registers;
- (c) send and receive configurations to and from the Meter;
- (d) compare configuration files from the Meter with desired files and report discrepancies;
- (e) read Meter billing data and load profile data;
- (f) generate Meter data and diagnostic reports for printing;
- (g) read, display and modify the present settings of field configurable items;
- (h) execute a billing period reset;
- (i) reset all consumption and demand quantities; and
- (j) not have the capability to alter the configuration files as generated by the Rate Development Program.

**6.8 Field Disk Serialization Program**

The ISO Metered Entity shall ensure that its supplier provides a Field Disk Serialization Program software package that associates a unique password with each copy of the Field Program. The Field Disk Serialization Program shall use an ASCII text file in a specified format as input and place a different password on one or more copies of a field disk generated by the Rate Development Program.

**6.9 DOS or Windows**

All software programs shall be PC DOS or Windows based. The Rate Development Program shall be either a Microsoft Windows 9x application or a DOS application capable of running under Microsoft Windows 9x without any loss of function. The Field Program and the Field Disk Serialization Program shall be DOS applications capable of running under PC-DOS Version 7 or later.

**6.10 Communication Protocol**

The protocol used for communication with the Meter through either the optical port or the optional modem shall be an asynchronous, byte oriented protocol.

**6.11 Optical Probe**

The Rate Development Program and the Field Program shall support use of a compatible optical probe (ABB Unicomm or similar) connected to the standard PC serial port of the Meter Programmer.

**7 Communication**

**7.1 Optical Port**

The primary communication port to the Meter for reading and programming of the internal data shall be an optically isolated communication port per ANSI C12.13, Type 2 or other serial port.

**7.2 Baud Rate**

The optical port shall communicate at a minimum of 9600 baud.

**7.3 Optical Port Location**

The optical port shall be located in the front of the Meter and be accessible without removing the Meter's cover. The optical port shall also be functional with the Meter cover removed.

**7.4 Optical Port Cable**

There shall be no cable connection between the optical port on the Meter cover and the register.

**7.5 RS232 or RS 485 or RSXXX.**

One RSXXX port shall be provided at the Meter for bi-directional communications (with security provisions included) to computers and/or data acquisition devices. The Meter must have the capability for being polled every 15 minutes for data by MDAS or a Compatible Meter Data Server. An optional RSXXX port or ports with read-only access can be provided for others desiring the data. All RSXXX ports shall be optically isolated.

The Meter shall be capable of being polled simultaneously by more than one entity on one or more of its ports without loss of data, interference, lockup or other such problems. In all cases, priority servicing shall be given to the ISO required RSXXX port (used by MDAS).

The Meter shall support and be implementable with ISO WEnet communication chains, including:

- (a) Meter RSXXX port to ISDN line (or lease line) to ATM Cloud POP to MDAS; and
- (b) Meter RSXXX port to Compatible Meter Data Server to Frame Relay or ISDN line to ATM Cloud POP to MDAS.

**8 Optional Meter Functions**

**8.1 Pulse Outputs**

The ISO may specify one to four channels of pulse outputs that are proportional to the consumption quantities. The pulse output values shall be programmable with pulse durations of at least 100 milliseconds. The outputs may be either 2-wire, Form A or 3-wire, Form C configuration.

**8.2 Current Loop**

The ISO may specify an additional serial communication port consisting of a 2-wire, 20 milliamp current loop that is optically isolated from the rest of the Meter. At a minimum, the baud rate shall be selectable as 300/ 1200/ 2400/ 9600 baud.

**8.3 Internal Modem**

The ISO may specify an internal modem having telephone communications at autobaud rates of up to 28800 baud. The modem shall include automatic baud select, configurable answer time window and configurable answer ringcounter.

The ring detect circuitry shall not be affected by spurious voltage rises in the telephone line.

**8.4 Demand Threshold Alarm**

The ISO may specify a kilowatt threshold relay that closes at a programmable demand value and stays closed for the remainder of the interval and until at least one complete interval does not exceed the threshold value. The value shall be independently programmable for each TOU rate season and schedule.

**9 Accuracy**

**9.1 ANSI C12.10**

The Meter shall meet or exceed the accuracy specifications contained in ANSI C12.10 over its entire service life without the need for adjustment.

**9.2 Factory Calibration**

The Meter shall be calibrated to provide the following level of accuracy:

- (a)  $\pm 0.2\%$  at full load at power factor of 100%;
- (b)  $\pm 0.25\%$  at full load at power factor of 50% lag;
- (c)  $\pm 0.25\%$  at full load power factor at 50% lead; and
- (d)  $\pm 0.25\%$  at light load at power factor of 100%.

**9.3 Test Equipment**

Meter accuracy and calibration tests, both shop and field, shall require only standard test equipment. No special laboratory-type test equipment or test procedures shall be required to assure accuracy of the Meter.

**9.4 Creep**

The Meter shall not creep. No pulse generation or registration shall occur for any consumption or demand quantity which depends on current while the current circuit is open.

**9.5 Starting Current**

The Meter shall start to calculate consumption and demand quantities when the per phase current reaches Class 20 - 5 milliamps.

**9.6 Start-up Delay**

The Meter shall start to calculate consumption and demand quantities less than 3 seconds after power application.

**9.7 Pulse Outputs**

Pulse outputs shall have the same accuracy as the Meter displays.

**10 Electrical Requirements**

**10.1 Meter Forms, Voltage Ratings and Classes**

The following forms, voltage ratings and classes of Meters are approved for installation on the ISO Controlled Grid:

- (a) A – Base Type, FORMS 5A and 9A, 120 Volts, Class 10 and Class 20;
- (b) Socket – Type, FORMS 5S and 9S, 120 Volts, Class 10 and Class 20;
- (c) Switchboard – Type, 2 Element and 3 Element, 120 Volts, Class 10 & Class 20; and
- (d) Rack mounted meter assemblies – 2 element and 3 element, Class 10 & Class 20.

**10.2 Circuit Boards**

All circuit boards in the Meter shall be designed to meet ISO's environmental and electrical testing requirements and the service life and performance expectations detailed in this Exhibit.

**10.3 LCD Display Connectors**

Gold pins encased in an elastomer or carbonized contacts, or some other better construction, shall be used to connect the LCD display to the register circuit board.

**10.4 Metering Application**

The Meter shall be used to meter electrical service on a continuous duty.

**10.5 Connections**

The Meter's internal electrical connections shall be in accordance with ANSI C12.10.

**10.6 Meter Register Power Supply**

The Meter register shall be powered from the line side of the Meter and shall have provision for external backup power. Neither the normal power supply nor the backup power supply (when so equipped) shall be fused.

**10.7 Clock**

Clocks shall meet the following requirements:

- (a) the clock internal to the Meter shall be accurate within 2 minutes per week (0.02%) when not synchronized to the ISO Controlled Grid operation line frequency and shall be resettable through the ISO communications interface. The ISO will transmit a periodic master synchronizing signal to the meter;
- (b) the internal clock shall have two modes of operation as follows:
  - i. the clock shall synchronize with the ISO Controlled Grid operation line frequency until an outage occurs. During the outage, the clock will then synchronize with its own internal crystal. When power returns, the clock shall resynchronize with the ISO's master synchronizing signal and follow line frequency; and
  - ii. the clock shall always synchronize with its own internal crystal, as a default; and
- (c) the choice of clock mode shall be programmable.

**10.8 Batteries**

Batteries shall meet the following requirements:

- (a) when the Meter design requires a battery as auxiliary power supply, the requirements of Section 3.7 shall apply;
- (b) the battery shall be secured with a holder securely attached to the Meter. The battery holder and electrical connections shall be designed to prevent the battery from being installed with reversed polarity;
- (c) replaceable batteries shall be easily accessible by removing the Meter cover. Battery replacement while the Meter is in service shall not interfere with any of the specified functions;
- (d) no fuse external to the battery shall be installed in the battery circuit;
- (e) the Meter battery shall provide a minimum carryover capability at 23° C for the functions listed in Section 3.7 and have a 15 year shelf life; and
- (f) the following information shall be clearly identified on the battery:
  - i. manufacturer;

- ii. date of manufacture, including year and month (i.e. 9601) or year and week (i.e. 9644);
- iii. polarity;
- iv. voltage rating; and
- v. type.

#### **10.9 Electromagnetic Compatibility**

The Meter shall be designed in such a way that conducted or radiated electromagnetic disturbances as well as electrostatic discharges do not damage nor substantially influence the Meter.

#### **10.10 Radio Interference Suppression**

The Meter shall:

- (a) not generate conducted or radiated radio frequency noise which could interfere with other equipment; and
- (b) meet FCC Part 15 Class B computing device radio frequency interference standards.

### **11 Mechanical Requirements**

#### **11.1 General**

The Meter shall not pose any danger when operating under rated conditions in its normal working position. Particular attention should be paid to the following:

- (a) personnel protection against electric shock;
- (b) personnel protection against effects of excessive temperature;
- (c) protection against the spread of fire; and
- (d) protection against penetration of solid objects, dust or water.

#### **11.2 Corrosion Protection**

All parts of the Meter shall be effectively protected against corrosion under normal operating conditions. Protective coatings shall not be damaged by ordinary handling nor damaged due to exposure to air. The Meter shall be capable of operating in atmospheres of up to (and including) 95% relative humidity condensing.

#### **11.3 Solar Radiation**

The functions of the Meter shall not be impaired, the appearance of the Meter shall not be altered and the legibility of the Meter nameplate and other labels

shall not be reduced due to exposure to solar radiation throughout the service life of the Meter.

#### **11.4 Corrosive Atmospheres**

ISO may specify additional requirements for Meters used in corrosive atmospheres.

#### **11.5 Meter Package**

The Meter Package shall meet the following requirements:

- (a) the socket Meter's dimensions shall be in accordance with ANSI C12.10;
- (b) the socket Meter shall be designed for mounting outdoors in a standard meter socket;
- (c) Meters shall have a twist-on self locking cover in accordance with ANSI C12.10 requirements. The Meter cover shall:
  - i. not contain a metal or conducting locking ring;
  - ii. shall be resistant to ultraviolet radiation;
  - iii. be sealed in such a way that the internal parts of the Meter are accessible only after breaking the seal(s);
  - iv. for any non-permanent cover deformation, not prevent the satisfactory operation of the meter;
  - v. for the "sprue" hole (mold fill hole), not affect the ability to read the Meter; and
  - vi. have an optical port per ANSI C12.13, Type 2.
- (d) the method of securing the socket Meter to the meter socket shall be with either a sealing ring or a high security sealing device;
- (e) the billing period demand reset device shall accommodate a standard electric meter seal and shall remain in place with friction if not sealed; and
- (f) filtered ventilation shall be provided in the base of the Meter to prevent condensation inside the Meter.

#### **11.6 Nameplate**

The Meter nameplate shall:

- (a) comply with the minimum information requirements of ANSI C12.10;
- (b) include the Meter's serial number and the date of manufacture. The manufacturing date shall include the year and month (i.e. 9601) or the year and week (i.e. 9644);



- (c) have the following attributes:
  - i. it shall be mounted on the front of the Meter;
  - ii. it shall not be attached to the removable Meter cover;
  - iii. it shall be readable when the Meter is installed in the Meter socket or panel; and
  - iv. it shall not impair access for accuracy adjustment or field replacement of components (such as the battery).
- (d) include ANSI standard bar coding; and
- (e) include an easily erasable strip with minimum dimensions of 3/8 inch by 1½ inches for penciling in items such as meter multiplier or the Meter tester's initials.

## **12 Security**

### **12.1 Billing Period Reset**

Operation of the billing period demand reset mechanism shall require breaking of a mechanical sealing device. Use of common utility-type sealing devices shall be accommodated.

### **12.2 Meter Password**

The Meter shall be programmable by the Meter Programmer with up to four unique passwords to prevent unauthorized tampering by use of the optical port or the optional modem. For meters procured after 1/1/98, passwords must be a minimum of four (4) alpha/numeric characters. Access rights and capabilities shall be individually programmable for each password. The Meter shall accept multiple requests from different sources without error, lockup or loss of data.

### **12.3 Test Mode**

Removal of the Meter cover shall be required to activate the Test Mode.

### **12.4 Program Security**

At least four levels of security shall be available for the Rate Development Program and the Field Program. These levels include:

- (a) Read Register— the user can only read billing and load profile data;
- (b) Read Register— the user can only read billing and load profile data, and perform a billing period reset;
- (c) Read/Modify Register— the user can perform functions listed in 12.4(a) and 12.4(b), plus download Meter configuration files and operate other features of the Field Program; and

- (d) Read/Modify/Program Register— the user can perform functions listed in 12.4(a), 12.4(b) and 12.4(c), plus develop Meter configuration files and operate additional features of the Rate Development Program.

**12.5 Revenue Protection**

Meters that help prevent Energy diversion are preferred.

**13 Meter Approval Testing**

**13.1 General Requirement**

This Section outlines the testing required by the ISO to assure the quality of Meters, the ISO will not approve Meters which have not undergone the testing referred to in this Section.

*ISO Testing using Independent Laboratory*

In addition to the required manufacturer testing specified in this Section, the ISO reserves the right to require independent laboratory test data resulting from the performance of tests as outlined in this Section.

In addition to the applicable testing requirements of the ANSI C12 standards, the qualification tests specified in this Section shall be conducted to confirm correct operation of the Meter.

The qualification testing is required for new Meter designs and for Meter product changes.

The ISO Metered Entity shall ensure that its supplier provides a certified test report documenting the tests and their results. The test report will be signed by the supplier and shall include all charts, graphs and data recorded during testing.

**13.2 Meter Failure Definition**

A Meter shall be designated as failed if any of the following events occur:

- (a) failure of the Meter to perform all of the specified functions;
- (b) failure of the Meter to meet the technical performance specifications included in this Exhibit;
- (c) signs of physical damage or performance degradation as a result of a test procedure, including effects which could shorten the service life of the Meter;
- (d) the occurrence of an unexpected change of state, loss of data or other unacceptable mode of operation for the Meter as a consequence of a test procedure; and

- (e) failures shall be classified as a hardware, firmware or software failure or a combination according to the following definitions:
- i. firmware failures are errors made during the fabrication of programmable read only memory (PROM) chips such that the required program or instruction set that the microprocessor is to perform is incorrect;
  - ii. hardware failures are failures that are physical in nature and directly traceable to the component level. Visual observances such as discoloration, cracking, hardening of cables, poor solder joints, etc. are also included. Failures of DIP switches, jumpers, and links are also included; and
  - iii. software failures are failures such as the loss or unintended change of data, the inability to program the Meter, the loss of the Meter program or the erroneous output or display of false information.

### **13.3 Meter Design Rejection Criteria**

A Meter design will be rejected if any of the following events occur:

- (a) the failure of one Meter during one test procedure and the failure of a second Meter during another test procedure; and
- the failure of two or more Meters during the same test procedure.

### **13.4 Test Setup**

- (a) the Meter shall be connected to its normal operating supply voltage with a fully charged Power Failure Backup System. The Meter shall be energized throughout the duration of the test procedures, unless otherwise stated;
- (b) before testing commences, the Meter shall be energized for a minimum of two hours at room temperature;
- (c) all tests shall be conducted at room temperature unless otherwise specified; and
- (d) the Meter shall be loaded to the nameplate test amperes at 100% power factor for all tests unless otherwise indicated.

### **13.5 Functional Test (No Load Test)**

This test confirms the operation of the Meter functions in accordance with this Exhibit:

- (a) the Meter shall be energized with no load;
- (b) the Meter shall be programmed with the ISO supplied parameters using a Meter Programmer;

- (c) operation of the specified functions will be verified over 24 hours by observing the Meter display and by interrogating the contents of Meter registers via a Meter Programmer; and
- (d) to pass this test, the Meter shall operate as specified with no observed anomalies.

**13.6 Accuracy Test**

This test confirms the accuracy of the Meter:

- (a) the accuracy of the Meter shall be tested for all combinations of the following conditions:
  - i. at ambient temperature, 85°C and -20°C;
  - ii. at power factors of 100%, 50% lag and 50% lead; and
  - iii. at 0% to 120% of class current;
- (b) accuracy curves shall be provided for all combinations of the conditions; and
- (c) to pass this test, the Meter shall have the indicated accuracy at ambient temperature for the following load conditions:
  - i.  $\pm 0.2\%$  at Full load at power factor of 100%;
  - ii.  $\pm 0.25\%$  at Full load at power factor of 50% lag;
  - iii.  $\pm 0.25\%$  at Full load at power factor of 50% lead; and
  - iv.  $\pm 0.25\%$  at Light load at power factor of 100%.

**13.7 Line Voltage Variation Test**

This test confirms the Meter's correct operation under varying line voltage conditions:

- (a) the Meter shall be tested at line voltages ranging from 80% to 120% of rated voltage under the following load conditions:
  - i. full load at power factor of 100%; and
  - ii. light load at power factor of 100%; and
- (b) to pass this test the Meter shall meet the following criteria:
  - i. operate as specified;
  - ii. have an accuracy as specified in Section 13.6(c) throughout the 80% to 120% voltage range; and
  - iii. the Power Failure Backup System shall not take over when the voltage is above 80% and below 120% of rated.

**13.8 Momentary Power Loss**

This test confirms the Meter's ability to withstand momentary power outages:

- (a) the test will be performed by opening the AC power supply input for the specified duration;
- (b) twelve tests shall be conducted using the following sequence:
  - i. energize the Meter;
  - ii. simulate a power loss of 0.5 cycles at 60 hertz;
  - iii. lengthen each succeeding simulated power outage by 0.5 cycles until a duration of 6.0 cycles is attained; and
  - iv. the start of each successive test shall be delayed by one minute; and
- (c) to pass this test, the Meter shall operate as specified with no observed anomalies.

**13.9 Power Failure Backup System Test**

This test confirms the carryover capability of the Power Failure Backup System:

- (a) this test shall be conducted at ambient temperature using a new or fully charged battery;
- (b) the test shall be conducted using the following sequence:
  - i. Energize the Meter at full load for two hours;
  - ii. De-energize the Meter for 24 hours; and
  - iii. Verify the integrity of programs and metering data stored in memory; and
- (c) to pass this test, the Meter shall operate as specified with no observed anomalies.

**13.10 Brownout and Extended Low Voltage Test**

This test confirms the Meter's ability to withstand brownouts and extended low voltage conditions:

- (a) the test shall be conducted using the following sequence:
  - i. Energize the Meter and verify correct operation;
  - ii. Slowly lower the line voltage to 80% of nominal;
  - iii. Operate the Meter at this voltage level for 6 hours;
  - iv. Verify correct Meter operation;
  - v. Lower the line voltage to 50% of nominal;

- vi. Operate the Meter at this voltage level for 6 hours; and
  - vii. Verify correct operation of the Meter and the Power Failure Backup System; and
- (b) to pass this test, the Meter shall operate as specified with no observed anomalies.

**13.11 Effect of Power Failure Backup System Voltage Variation on Clock Accuracy**

This test confirms the effects of the battery voltage on the Meter's clock accuracy:

- (a) the Meter shall be tested with the battery disconnected and an auxiliary DC power supply connected to the battery carryover circuit. The DC power shall be varied from 95% to 105% of nominal battery voltage; and
- (b) to pass this test, the accuracy of the Meter clock shall be within 0.02% (2 minutes per week) with a voltage variation of 5 % of nominal battery voltage at ambient temperature.

**13.12 Effect of Temperature Variation on Clock Accuracy**

This test confirms the effects of temperature on the Meter clock accuracy:

- (a) this test shall be conducted with the register in the battery carryover mode;
- (b) the temperature shall be varied from 85°C to -20°C;
- (c) the Meter shall be exposed to each temperature for a least 2 hours prior to testing; and
- (d) to pass this test, the accuracy of the Meter clock shall be within 0.02% (2 minutes per week) at ambient temperature, 85°C, and -20°C.

**13.13 Temperature Cycle Test**

This test confirms the effects of an accelerated temperature cycle on the Meter:

- (a) the Meter cover shall be removed during this test;
- (b) the test duration shall be 7 days (168 hours);

- (c) the temperature shall be cycled once per 24 hour period;
- (d) temperature shall be varied linearly during the tests at a constant rate not to exceed 20°C per hour;
- (e) humidity shall not be controlled during the test;
- (f) the Meter shall be de-energized during the fourth and fifth cycles of the test to verify the performance of the Power Failure Backup System during temperature fluctuations;
- (g) each 24 hour cycle shall consist of the following:
  - i. begin test at +20°C (or room temperature if within 5°C);
  - ii. ramp up to +85°C in approximately 3.25 hours;
  - iii. hold at +85°C for approximately 10.75 hours;
  - iv. ramp down to -20 C in approximately 5.25 hours;
  - v. hold at -20°C for approximately 2.75 hours;
  - vi. ramp up to +20°C in approximately 2.00 hours; and
  - vii. begin next 24 hour cycle or end test after 7 cycles; and
- (h) to pass this test, the Meter shall operate as specified with no observed anomalies for the entire test period.

#### 13.14 Humidity Cycle Test

This test confirms the effects of an accelerated humidity cycle on the Meter:

- (a) the Meter cover shall be removed during this test, or a meter cover with a large hole at the bottom may be substituted;
- (b) the duration of the test shall be 24 hours;
- (c) condensation may form on the Meter during the test;
- (d) temperature shall be varied linearly during the tests at a constant rate not to exceed 20°C per hour;
- (e) humidity shall not be controlled during temperature changes;
- (f) the test shall consist of the following sequence:
  - i. begin at +20°C (or room temperature if within 5°C);
  - ii. ramp up to +85°C in approximately 3.25 hours;
  - iii. ramp up to a relative humidity of 95% in approximately 1 hour;
  - iv. hold at +85°C at a relative humidity of 95% ±1% for approximately 14.5 hours;
  - v. ramp down to +20°C in approximately 3.25 hours;

- vi. concurrently with Section 13.14(f)v. ramp down to a relative humidity of 75% in approximately 15 minutes;
  - vii. hold relative humidity at 75% for remainder of temperature ramp down; and
  - viii. hold at 20°C at a relative humidity of 75%  $\pm$ 1% for approximately 2 hours; and
- (g) to pass this test, the Meter shall operate as specified with no observed anomalies for the entire test period.

**13.15 Insulation Withstand Test**

This test confirms the insulation levels of the Meter:

- (a) the Meter shall not be energized for this test;
- (b) the insulation between power line voltage and current carrying parts and any other metallic or conductive part shall be tested by applying 2500 volts rms, 60 Hz for a period of one minute; and
- (c) to pass this test the leakage current shall not exceed one milliamp for the duration of the test and the Meter shall operate after completion of the test.

**13.16 Standard Waveform Surge Withstand Test**

This test confirms the ability of the Meter to withstand voltage transients:

- (a) the Meter shall be energized but not loaded during the test;
- (b) the test shall be conducted in accordance with the latest recognized industry standards;
- (c) the oscillatory test wave shall be applied at a repetition rate of 100 tests per second for 25 seconds;
- (d) the test signal shall be applied in both the common and transverse modes;
- (e) the test shall be conducted on all voltage, current, and optional equipment inputs and outputs;
- (f) this test will be performed two times with a maximum period of 1 minute between tests; and



- (g) to pass this test, the Meter shall operate as specified with no observed anomalies;

**13.17 Fast Transient Waveform Surge Withstand Test**

This test confirms the ability of the Meter to withstand fast voltage transients:

- (a) the Meter shall be energized but not loaded during the test;
- (b) this test shall be conducted in accordance with the latest industry recognized standard;
- (c) the unipolar test wave shall be applied at a repetition rate of 100 tests per second for 25 seconds;
- (d) the test signal shall be applied in both the common and transverse modes;
- (e) the test shall be conducted on all voltage, current, and optional equipment inputs and outputs;
- (f) this test will be performed two times with a maximum period of 1 minute between tests; and
- (g) to pass this test, the Meter shall operate as specified with no observed anomalies.

**13.18 Powerline Surge Voltage and Current Test**

This test confirms the ability of the Meter to withstand power line voltage and current surges:

- (a) the meter shall be energized but not loaded during the test;
- (b) the test shall be performed using the unipolar and the ring waveform specified in the latest industry recognized standard;
- (c) the test surges shall be applied to the power line in both the normal and common modes;
- (d) the following number of surges shall be applied at the indicated voltages:
  - i. 12 surges at 6 kV;
  - ii. 12 surges at 5 kV; and
  - iii. 36 surges at 4 kV.
- (e) the first test surges at 5 kV and 6 kV shall be injected at 0 degrees on the positive half-cycle of the waveform. Each successive test

- surge shall be shifted 15 degrees on the positive half-cycle of the waveform up to 180 degrees;
- (f) the first test surge at 4 kV shall be injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge shall be shifted 15 degrees on both the positive and negative half-cycles of the waveform up to 360 degrees;
  - (g) sufficient time shall be allowed in between test surges for the electronic components to return to normal operating temperatures. A minimum of 5 minutes shall be allowed between each surge test;
  - (h) the applied test signals shall be monitored and recorded. The Meter under test shall be monitored to confirm that correct operation is maintained;
  - (i) after the tests each meter shall be inspected for visible damage, such as signs of arcing, etc.; and
  - (j) to pass this test, the Meter shall operate as specified with no visible damage observed.

**13.19 Electrostatic Susceptibility Test**

This test verifies the ability of the Meter to withstand electrostatic discharges:

- (a) this test shall be tested in accordance with the latest revision of Military Handbook DOD-HDBK-263;
- (b) the test generator shall simulate a human body with a capacitance of 100 picofarads and a series resistance of 1500 ohms;
- (c) the test probe shall be a 3/8 inch rod with a rounded tip;
- (d) the following procedures shall be followed:
  - i. test all surfaces, including switches and buttons and other components that will be contacted by personnel under normal handling, installation and use of the Meter. This shall include any safety grounded or neutral terminals on the exterior of the meter enclosure;
  - ii. with the test probe voltage set at 10 kV, contact each of the above surfaces with the probe;
  - iii. with the test probe voltage set to 15 kV, locate the probe to within approximately 0.5 inch (avoiding contact) with each of the above surfaces; and
  - iv. the functions of the Meter shall be periodically verified for correct operation; and
- (e) to pass this test, the Meter shall operate as specified with no observed anomalies.

**13.20 Visual Inspection**

This test shall be performed after all of the other tests except the Shipping Test have been performed:

- (a) visual inspection shall be performed for all electronic circuit boards in the Meter; and
- (b) to pass this test, the Meter shall not have any defect which would result in rejection under the latest recognized industry standards on any electronic circuit board.

**13.21 Shipping Test**

This test confirms the ability of the Meter and its packaging to withstand the rigors of shipping and handling:

- (a) the Meter shall not be energized during this test, but shall be programmed and operating in the power Backup mode;
- (b) the packaged Meter shall be subjected to the following tests:
  - i. the National/International Safe Transit Association Pre-shipment Test Procedures, Project IA; and
  - ii. Method B, Single Container Resonance Test, of the latest revision of American Society for Testing and Materials (ASTM) Standard D-999. Test intensities, frequency ranges and test durations shall meet or exceed the recommended values of ASTM D-999; and
- (c) to pass this test, the Meter shall be inspected and tested to verify that no damage had occurred and that the time and all stored data is correct.

**14 Safety**

**14.1 Hazardous Voltage**

Hazardous voltages shall not be easily accessible with the Meter cover removed.

**14.2 Grounding**

All accessible conductive parts on the exterior of the Meter and conductive parts that are accessible upon removal of the Meter cover shall be electrically connected to the Meter grounding tabs. All connections in the grounding circuit shall be made with an effective bonding technique.

**14.3 Toxic Materials**

No materials that are toxic to life or harmful to the environment shall be exposed in the Meter during normal use.

**14.4 Fire Hazard**

Materials used in the construction of the Meter shall not create a fire hazard.

**15 Data Security And Performance**

- (a) Manual access for changing data or reprogramming shall require the physical removal or breaking of an ISO seal by the ISO or an ISO Authorized Inspector.
- (b) No loss of data shall occur as a result of the following events within design specifications:
  - i. power outages, frequency changes, transients, harmonics, reprogramming, reading; and
  - ii. environmental factors—dampness, heat, cold, vibration, dust.
- (c) 5-minute interval data for the most recent 60 day period shall always be available and accessible via the communications interface or the optical interface.

**16 Documentation**

**16.1 Hardware Documentation To Be Provided For ISO Review**

- (a) Drawing(s) showing the external meter connections.
- (b) Instruction booklets detailing the necessary procedures and precautions for installation of the Meter provided for use by field personnel during initial installation written in the style of a step by step outline.
- (c) One (1) technical/maintenance manual and one (1) repair manual shall be provided for each Meter style. These manuals shall be sufficiently detailed so that circuit operation can be understood and equipment repair facilitated.
- (d) The above documents shall be submitted for approval by ISO before equipment is installed. Approval of documents by the ISO shall not relieve any responsibility for complying with all the requirements of this Exhibit.

**16.2 Software**

A complete set of manuals detailing the operation of the Rate Development Program, the Field Program, and the Field Disk Serialization Program shall be provided to ISO for review. These manuals shall explain to a person with only basic computer knowledge how to generate and download Meter configuration files.

**17 Applicable Standards**

The standards referred to in Appendix J to the ISO Tariff shall apply to all Meters.

**18 Definitions**

The following terms and expressions used in this Exhibit are detailed as set forth below:

**“Ambient Temperature”** means temperature of  $23^{\circ}\pm 2^{\circ}$  Celsius.

**“Average Power Factor”** means the power factor calculated using the average active and reactive power flows over the latest demand interval.

**“Delivered”** means Energy (active, reactive, or apparent) that flows from the ISO Controlled Grid to an End-User.

**“Failed Meter”** means a Meter in which any part or component, except the removable battery, has failed.

**“Failure”** means any hardware, firmware or software failure, or any combination.

**“Field Disk Serialization Program”** means a software package that allows the user to assign a separate password to each disk copy of the Field Program.

**“Field Program”** means a software package that allows the user to download Meter configuration files into the Meter and perform other testing and maintenance activities.

**“Hazardous Voltage”** means any voltage exceeding 30 volts rms.

**“Meter”** means all single phase and three phase electricity meters with electronic registers, including hybrid and solid state meters, but excluding

solid state recorders, and including any optional devices included under the Meter cover.

**“Meter Programmer”** means the PC DOS based laptop computers used for meter reading/programming.

**“MSDS”** means the Material Safety Data Sheet.

**“Power Failure Backup System”** means a sub-system in the Meter that provides power to the electronic circuitry when the normal power line voltage is below operating limits. The sub-system usually consists of a battery and may or may not include a super capacitor.

**“Quadrant”** means the term used to represent the direction of power flows (active and reactive) between the ISO Controlled Grid and an End-User. The 4 quadrants are defined as follows:

- (a) Quadrant 1 – shall measure active power and reactive power delivered by the ISO Controlled Grid;
- (b) Quadrant 2 – shall measure active power received by ISO Controlled Grid and reactive power delivered by the ISO Controlled Grid;
- (c) Quadrant 3 – shall measure active power and reactive power received by the ISO Controlled Grid; and
- (d) Quadrant 4 – shall measure active power delivered by ISO Controlled Grid and reactive power received by the ISO Controlled Grid.

**“Rate Development Program”** means a software package that allows the user to generate Meter configuration files including operating parameters and TOU schedules.

**“Received”** means Energy (active, reactive or apparent) that flows from a Generator to the ISO Controlled Grid.

**“RFI”** means the Radio Frequency Interference.

**“Temperature tolerance”** means  $\pm 2^{\circ}$  Celsius.

**Attachment 1**  
**Physical and Electronic Attribute Criterion for Electricity Meters**

Test / Inspection Description	Pass	Fail
<b>1. Bayonets</b> A. Missing or loose parts, i.e., cotter pin, arc gap, etc.		
<b>2. Meter Base</b> A. Any cracked and/or missing/damaged gasket B. Any broken leg C. Missing or loose voltage link or screw D. Any missing or loose arc gaps E. Missing or damaged ventilation screen or filter on applicable meter F. Sealing hole unusable for sealing G. Any chips on upper half of meter (gasket ring area) H. Any chips which may jeopardize meter integrity I. Any sign of water damage in meter such as corrosion, oxidation, stain J. Missing or loose rivets holding frame to base		
<b>3. Meter Frame</b> A. Nameplate data incorrect or flawed B. Missing or loose hardware on frame		
<b>4. Module</b> A. Loose or defective power connectors B. Improper routing of voltage leads C. Improper fit (loose or crooked) D. Crimped or pinched voltage leads E. Incorrect module F. Calibration screw access should not be significantly affected (or covered)		
<b>5. Meter Cover</b> A. Wiring to communication port is correct & solid B. Proper meter cover is used for meter type and class C. Mechanical reset mechanism works properly D. Proper alignment, positioning, and operation of all cover mechanisms		
<b>6. Electronic Register</b> A. Program register to verify acceptance of rate schedule B. Check display that all segments are operational C. Check battery carryover function, if appropriate D. Check register tracking by inputting disk revolutions E. Check for any visual defects in the register assembly		

Only scratches and/or chips that are cosmetically or functionally objectionable will be classified as defective and failing.

**Attachment 2  
 Meter Display Items**

<b>Display Item</b>	<b>Normal Mode</b>	<b>Alternate Mode</b>	<b>Test Mode</b>
<b>Minimum Requirements for Delivered kWh</b>			
Complete Display (Segment) Test	x	x	
Demand Reset Count		x	
Demand Reset Date		x	
Instantaneous kW	x	x	
Interval length		x	
Minutes of Battery Use		x	
Present time	x	x	
Previous Billing Rate A kWh		x	
Previous Billing Rate A Maximum kW		x	
Previous Billing Rate B kWh		x	
Previous Billing Rate B Maximum kW		x	
Previous Billing Rate C kWh		x	
Previous Billing Rate C Maximum kW		x	
Previous Billing Rate D kWh		x	
Previous Billing Rate D Maximum kW		x	
Previous Billing Total kWh		x	
Previous Season Rate A kWh	x	x	
Previous Season Rate A Maximum kW	x	x	
Previous Season Rate B kWh	x	x	
Previous Season Rate B Maximum kW	x	x	
Previous Season Rate C kWh	x	x	
Previous Season Rate C Maximum kW	x	x	
Previous Season Rate D kWh	x	x	
Previous Season Rate D Maximum kW	x	x	
Previous Season Total kWh		x	
Program ID		x	
Rate A kWh	x	x	
Rate A Maximum kW	x	x	
Rate B kWh	x	x	
Rate B Maximum kW	x	x	
Rate C kWh	x	x	
Rate C Maximum kW	x	x	
Rate D kWh	x	x	
Rate D Maximum kW	x	x	



**Attachment 2  
 Meter Display Items (cont.)**

<b>Display Item</b>	<b>Normal Mode</b>	<b>Alternate Mode</b>	<b>Test Mode</b>
<b>Minimum Requirements for Delivered kWh (cont.)</b>			
Total kWh	x	x	x
Wh per disk revolution (Kh)		x	
Wh per pulse (Ke)		x	
<b>Minimum Requirements for Test Mode</b>			
Present Interval Demand—kW			x
Pulse count			x
Time left in subinterval			x
Total kWh			x
<b>Additional requirements for Received kWh (if specified)</b>			
Previous Billing Total Received kWh		x	
Previous Season Total Received kWh		x	
Total Received kWh	x	x	
<b>Additional requirements for kVARh (if specified)</b>			
Maximum Delivered kVAR		x	
Maximum Received kVAR		x	
Previous Billing Maximum Delivered kVAR		x	
Previous Billing Maximum Received kVAR		x	
Previous Billing Total Delivered kVARh		x	
Previous Billing Total Received kVARh		x	
Previous Season Maximum Delivered kVAR		x	
Previous Season Maximum Received kVAR		x	
Previous Season Total Delivered kVARh		x	
Previous Season Total Received kVARh		x	
Total Delivered kVARh		x	
Total Received kVARh		x	
<b>Additional requirements for kVAh (if specified)</b>			
Maximum Delivered kVA		x	
Maximum Received kVA		x	
Previous Billing Maximum Delivered kVA		x	
Previous Billing Maximum Received kVA		x	
Previous Billing Total Delivered kVAh		x	
Previous Billing Total Received kVAh		x	
Previous Season Maximum Delivered kVA		x	
Previous Season Maximum Received kVA		x	

**Attachment 2  
 Meter Display Items (cont.)**

<b>Display Item</b>	<b>Normal Mode</b>	<b>Alternate Mode</b>	<b>Test Mode</b>
<b>Additional requirements for kVAh (cont.)</b>			
Previous Season Total Delivered kVAh		x	
Previous Season Total Received kVAh		x	
Total Delivered kVAh		x	
Total Received kVAh		x	
<b>Additional requirements for Power Factor (if specified)</b>			
Quadrant 1 Average Power Factor		x	
Quadrant 2 Average Power Factor		x	
Quadrant 3 Average Power Factor		x	
Quadrant 4 Average Power Factor		x	
Total Average Power Factor Delivered		x	
Total Average Power Factor Received		x	

**EXHIBIT 2 TO APPENDIX D**

**ISO SPECIFICATION  
FOR CERTIFICATION OF OIL-FILLED,  
WOUND INSTRUMENT TRANSFORMERS  
FOR REVENUE METERING**

**1 Purpose**

This Exhibit specifies the technical requirements for reliable high-accuracy Current Transformers (CT) and Voltage Transformers (VT) to be used for revenue quality metering on the ISO Controlled Grid.

**2 Scope**

**2.1** This Exhibit applies only to the following:

- Oil-filled Single-Phase CTs - 35kV-230kV.
- Oil-filled Single-Phase VTs - 35kV-230kV.
- Oil-filled Single-Phase Combination Current/Voltage Transformers - 35kV-230kV.

**2.2** This Exhibit applies only to the following Oil-filled Wound Devices, which are VTs < 35kv.

VTs > 230kv must be individually specified in accordance with the engineered installations.

**3 Standards**

All instrument transformers covered by this Exhibit shall be designed, manufactured, tested and supplied in accordance with the applicable standards referred to in Appendix J to the ISO Tariff.

**4 Definitions**

**“Hermetically Sealed”** means completely sealed by fusion, soldering, etc., so as to keep air or gas from getting in or out (i.e. airtight).

**“Metering Unit”** means one or more Voltage element(s) and one or more Current element(s) contained in one common housing.

**“BIL Rating”** means basic lightning impulse insulation level.

**“Burden Rating”** means the total impedance (in ohms) that can be connected to the secondary circuit(s) of an instrument transformer while still maintaining metering accuracy of plus-or-minus 0.3%

## **5 Specifications**

### **5.1 General**

All instrument transformers covered by this Exhibit shall be hermetically sealed, oil-filled type and have a minimum BIL Rating appropriate for the designated nominal System voltage:

- 60 - 69 kV – 350 kV BIL
- 115 kV – 550 kV BIL
- 230 kV – 900 kV BIL

### **5.2 Current Transformers**

**5.2.1** Current Transformer windings (typical configurations) shall be either:

- (a) a single primary winding and single secondary winding with dual ratio tap;
- (b) a dual primary winding and a single ratio tap;
- (c) a single primary winding and one or more secondary windings with dual ratio tap(s); or
- (d) other combinations as available and approved by the ISO.

#### **5.2.2 Rated primary current**

The rated primary current must be as specified by the ISO Metered Entity.

#### **5.2.3 Rated secondary current**

The rated secondary current must be 5 amperes @ rated primary current.

#### **5.2.4 Accuracy and burden**

All current transformers shall have an accuracy and burden of:

- (a) standard – plus-or-minus 0.3% @ B0.1 - 1.8 ohms, 10% - 100% rated current; or
- (b) optional – plus-or-minus 0.15 % @ B0.1 - 1.8 ohms, 5% - 100 % rated current.

#### **5.2.5 Continuous current rating factor**

All current transformers shall have a continuous current rating factor of:

- (a) standard – 1.5 @ 30 degrees C Ambient; or
- (b) optional – 1.0 @ 30 degrees C Ambient.

**5.2.6 Short time thermal current rating**

The short time thermal current rating varies with transformer rating as follows:  
25/50: 5 ratio, 4 kA RMS to 1500/3000:5 ratio, 120 kA RMS.

**5.2.7 Mechanical short time current rating**

The mechanical short time current rating varies with transformer rating as follows:  
25/50:5 ratio, 3 kA RMS to 1500/3000:5 ratio, 90 kA RMS.

**5.3 Voltage Transformers**

**5.3.1** Transformer windings shall consist of a single primary winding and one or more tapped secondary windings.

**5.3.2** Rated primary voltage, as specified by the ISO Metered Entity, must be 34,500 volts through 138,000 volts, L-N.

**5.3.3** Rated secondary voltage must typically be 115/69 volts.

**5.3.4** The ratio of primary to secondary windings must be 300/500:1 through 1200/2000:1.

**5.3.5 Accuracy and burden**

All voltage transformers shall have accuracy and burden of:

- (a) standard – plus-or-minus 0.3% through B. ZZ @ 90% through 110% of nominal voltage; or
- (b) optional – plus-or-minus 0.15% through B. Y 90% through 110% of nominal voltage.

**5.3.6 Thermal burden rating**

All voltage transformers shall have a thermal burden rating of:

- (a) 34.5 kV – 2500 VA, 60 hertz;
- (b) 60 kV & 69 kV – 4000 VA, 60 hertz; or
- (c) 115 kV – 6000 VA, 60 hertz.

**5.4 Combination Current/Voltage Transformers (Metering Units)**

Combination Current/Voltage Transformers shall maintain the same electrical, accuracy and mechanical characteristics as individual CTs and VTs. Physical dimensions may vary according to design.

**5.5 Grounding**

The neutral terminal of the VT shall exit the tank via a 5kV insulated bushing and be grounded by means of a removable copper strap to a NEMA 2-hole pad.

**5.6 Primary Terminals**

The primary terminals shall be tin-plated NEMA 4-hole pads (4"x4").

**5.7 Paint**

Exterior metal non current-carrying surfaces shall be painted with a weather-resistant paint system consisting of one primer and two industry recognized gray finish coats. As an option, for high-corrosion areas, special corrosion-resistant finishes (e.g. zinc-rich paint, stainless steel tank) shall be used.

**5.8 Porcelain**

Porcelain shall be of one-piece wet-process, glazed inside and outside. The outside color shall be in accordance with industry recognized gray glaze. The minimum creepage and strike-to-ground distances for various voltages shall be as follows:

<b>Voltage (nominal kV)</b>	<b>Creepage (inches)</b>	<b>Strike (inches)</b>
34.5	34	13
60 & 69	52	24
115	101	42
230	169	65
230 (1050 BIL)	214	84

**5.9 Insulating Oil**

The nameplate shall be of non-corroding material and shall indicate that the dielectric fluid is free of polychlorinated biphenyls by the inscription:

**"CONTAINS NO PCB AT TIME OF MANUFACTURE".**

**5.10 Accessories**

All units shall be equipped with the following standard accessories:

- 1/2" brass ball drain valve with plug
- 1" oil filling opening with nitrogen valve
- Magnetic oil level gauge, readable from ground level

- Primary bypass protector
- Sliding CT shorting link
- Four 7/8"x 2-3/8" mounting slots
- Four 1" eyebolts on base for four-point lifting sling
- 1/4" threaded stud secondary terminals
- Two conduit boxes, each with three 1-1/2" knockout

## **6 Testing**

The ISO Metered Entity shall ensure that, before shipment, each transformer is subjected to testing as prescribed by recognized industry standards and other tests including:

- (a) Applied voltage test for primary and secondary winding withstand to ground;
- (b) Induced voltage test for proper turn-to-turn insulation;
- (c) Accuracy test for ratio correction factor and phase-angle verification to confirm 0.3% metering accuracy per recognized industry standards;
- (d) Ratio test;
- (e) Insulation Power Factor test;
- (f) Polarity test;
- (g) Leak test to assure integrity of gaskets and seals; and
- (h) Partial Discharge Test may be done in conjunction with applied voltage testing to assure proper line-to-ground withstand.

The tests shall be submitted to the ISO on a formal certified test report.

## **7 Required Information**

The following drawings and information shall be required:

- (a) 3 sets of drawings showing physical dimensions including mounting holes and primary CT terminal details, nameplate. The ISO Metered Entity shall ensure that it receives a schematic of connections from its supplier; and
- (b) a copy of quality controls/quality assurance (QC/QA) manuals applicable to production of the transformer(s).



## **APPENDIX E**

### **TRANSFORMER AND LINE LOSS CORRECTION FACTORS**

#### **E 1 Introduction**

Transformer loss correction refers to the practice of metering electrical Energy delivered at a high-voltage billing point using metering equipment connected on the low-voltage side of the delivery point. The metering equipment is provided with a means of correction that adds to, or subtracts from, the actual active and reactive metered values in proportion to losses that are occurring in the transformer.

Transformer losses are divided into two parts:

- the core or iron loss (referred to as the no-load loss); and
- the copper loss (referred to as the load loss).

Both the no-load loss and the load loss are further divided into Watts and Var components.

The no-load (iron) loss is composed mostly of eddy current and hysteresis losses in the core. No-load loss varies in proportion to applied voltage and is present with or without load applied. Dielectric losses and copper loss due to exciting current are also present, but are generally small enough to be neglected.

The load (copper) watt loss ( $I^2 +$  stray loss) is primarily due to the resistance of conductors and essentially varies as the square of the load current. The Var component of transformer load loss is caused by the leakage reactance between windings and varies as the square of the load current.

Line losses are considered to be resistive and have  $I^2R$  losses. The lengths, spacings and configurations of lines are usually such that inductive and capacitive effects can be ignored. If line losses are to be compensated, they are included as part of the transformer load losses (Watts copper).

The coefficients, which are calculated at the calibration point of the meter, are entered into the meter as Percent Loss Watts Copper (%LWCU), Percent Loss Watts Iron (%LWFE), Percent Loss Vars Copper (%LVCU), and Percent Loss Vars Iron (%LVFE).

Percent losses are losses expressed as a percent of the full load on a meter.

The formulas used to determine the compensation values at a particular operating point are:

$$\text{WATTS Compensation Value} = \frac{\text{Measured Voltage}^2}{\text{Calibration Point Voltage}^2} * \%LWFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LWCU$$

$$\text{Vars Compensation Value} = \frac{\text{Measured Voltage}^4}{\text{Calibration Point Voltage}^4} * \%LVFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LVCU$$

## E 2 Calculating Transformer Loss Constants

Transformer Loss correction calculations with electronic meters are accomplished internally with firmware. Various setting information and test data is required to calculate the four values which are to be programmed into the meter.

The following information is required about meter installations:

- the transformer high voltage (HV) voltage rating
- the transformer kVa rating
- the transformer high voltage (HV) tap settings
- the transformer low voltage (LV) tap settings
- the transformer connection (wye or delta)
- the transformer phases (1 or 3)
- the voltage transformer (VT) ratio
- the current transformer (CT) ratio
- the number of meter elements

The following data from a transformer test report is required:

- no-load (iron) loss
- full-load (copper) loss
- percent impedance
- percent excitation current

The test data required may be obtained from the following sources:

- the manufacturer's test report
- a test completed by a utility or independent electrical testing company

If the transformer bank is used to deliver power to more than one entity (that is, it is a joint use transformer bank) additional data is required, including the:

- maximum available kVa from the transformer bank
- contracted amount of load to be compensated in kW
- contractual power factor amount to be used in calculations

**E 3            Calculating Line Loss Constants**

Line Loss correction calculations with electronic meters are accomplished internally with firmware. Various information about the radial line is required to calculate the value which is programmed into the meter. The resistance of the conductors are used to calculate a value which is added to the Watts copper loss value which is programmed into the meter. It is not practical to compensate for line losses in a network connected line, only radial lines.

The following information is required about the transmission line:

- the transmission line type
- the ohms per mile
- the length in miles of each type of line

**E 4            Applications**

*Joint Use Transformers*

Where a transformer bank is used to deliver power to more than one entity (that is, a joint use transformer bank), no-load iron losses are adjusted by the transformer percent use. This percent use is determined by dividing a negotiated contract kW load (*Contract kW*) at a negotiated power factor (*% Power Factor*) by the maximum available kVa from the transformer bank (*Max. Available kVa*).

$$\text{Percent Use} = \frac{\text{Contract kW} / \% \text{ Power Factor}}{\text{Max. Available kVa}}$$

*Switched Lines*

Line Loss correction for radial lines which are switched, must be based on a negotiated average resistance based on the typical operating characteristics.

*Transformer Load Tap Changer*

Transformers equipped with a load tap changer (i.e., which has the capability to change transformer voltage tap positions or settings under Load) for regulating voltage, must have the corrections calculated at the median tap voltage. Differences in the corrections must be minimal and must even out over time as the bank operates above and below the median tap voltage.

**E 5**

**Worksheets**

A pro forma Transformer and Line Loss Correction Worksheet which can be used to perform the above calculation is attached to this Appendix. Instructions for completing the worksheet are as follows:

- Complete the Name, Delivery, Location and Revision Date fields using the ISO Metered Entity's name, operating name, city, state, and the date of the calculation.
- Enter Transformer High Voltage (HV) winding rated voltage, this is the voltage at which the transformer tests were performed.
- Enter the HV and Low Voltage (LV) transformer tap settings.
- Enter 'Y' or 'D' to indicate the secondary winding connection of either wye or delta.
- Enter '1' to indicate that the transformer bank is comprised of single phase units or '3' to indicate the bank is comprised of three phase units.
- Enter '2' or '3' to indicate the number of elements in the meter.
- Enter the VT and CT ratios of the instrument transformers used in the metering.
- Enter 'Y' or 'N' to indicate if the transformer bank is utilized by more than one entity.
- Enter the negotiated contract and power factor for the joint use portion of the transformer (if any).
- If compensation coefficients are required at a calibration point other than five amps, enter the new value.
- Space is provided to make comments about the calculation or delivery configuration.
- Enter the manufacturer and serial number of the transformer(s).
- Enter the kVa rating of each bank. For multiple rated banks, the base kVa should be used. Enter the test data collected at base kVa.
- Enter the no-load losses in Watts from the test data.

- Enter the load losses in Watts from the test data.
- Enter the impedance from the test data.
- Enter the Exciting current from the test data.
- If the maximum available kVa from the transformer bank is more than the rated kVa, this value can be entered manually. An example may be for a triple rated transformer that has fans with a rating which is more than the base kVa. This value only affects the percent use calculation.
- Enter the line type for each type of line to be compensated.
- Enter the resistance in ohms per mile of each type of line to be compensated.
- Enter the total length in miles of each type of line to be compensated.

**E 6 Reference Materials**

The following additional references may be referred to for assistance when calculating the correction factors referred to in this Appendix.

- Handbook For Electricity Metering, Ninth Edition. Edison Electric Institute. Washington, D.C.
- Eastern Specialty Company Bulletin No. 63.
- American National Standard Institute. Test Code for Distribution, Power and Regulating Transformers.
- System Loss Compensation, Schlumberger Industries, Quantum Multifunction Meter Hardware Instruction Manual 1610, November 1993.
- Transformer Loss Calculation Method, Process System Manual, Appendix E.

**Transformer and Line Loss Correction Worksheet (Example)**

**TRANSFORMER AND LINE LOSS CORRECTION**

Name: Acme Power Company  
 Delivery: Delivery Number 5  
 Location: Surf Beach, CA  
 Rev. Date: 5/6/97

HV Rated Voltage:	110000 V	VT Ratio:	60:1
HV Tap:	101200 V	CT Ratio:	600:5
LV Tap:	13090 V	Joint Use (Y/N):	N
Trf. Conn. (Y/D):	Y	Metering Trf. Use:	100 %
Trf. Phase (1 or 3)	3	Contract kW:	10,000 kW
# Meter Elem.:	3	Power Factor:	95 %

Compensation Values (@ 5A F.L.)		Compensation Values at: 10 A	
Watt Fe Loss:	0.16 %	Watt Fe Loss:	.08 %
Watt Cu Loss:	0.53 %	Watt Cu Loss:	1.06 %
Watt Tot. Loss:	0.69 %	Watt Tot. Loss:	1.14 %
Var Fe Loss:	0.31 %	Var Fe Loss:	0.16 %
Var Cu Loss:	10.96 %	Var Cu Loss:	21.92 %
Var Tot. Loss:	11.27 %	Var Tot. Loss:	22.08 %

Comments:

**TRANSFORMER DATA**

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current
ABB 1000001	12000	22200 w	51360 w	8.84 %	0.45 %

Total kVa rating:	12000	Max Available kVa:	12000
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**LINE DATA**

	Resistance	Length
#1 Line Type:	Ohms/mile	miles
#2 Line Type:	Ohms/mile	miles
#3 Line Type:	Ohms/mile	miles
#4 Line Type:	Ohms/mile	miles
#5 Line Type:	Ohms/mile	miles

#6 Line Type:	Ohms/mile	miles
---------------	-----------	-------

**Transformer and Line Loss Correction Worksheet (Example,  
 continued)**

**TRANSFORMER AND LINE LOSS CORRECTION**

Name: ACME Power Company  
 Delivery: Delivery Number 5  
 Location: Surf Beach, CA  
 Rev. Date: 5/6/97

HV Rated Voltage:	110000 V	VT Ratio:	60:1
HV Tap:	101200 V	CT Ratio:	600:5
LV Tap:	13090 V	Joint Use (Y/N):	N
Trf. Conn. (Y/D):	Y	Metering Trf. Use:	100 %
Trf. Phase (1 or 3)	3	Contract kW:	10,000 kW
# Meter Elem.:	3	Power Factor:	95 %

**TRANSFORMERS**

Serial Number	kVa
ABB 1000001	12000

**\*\*TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS\*\***

**SERIES TEST**

Test Load	% Iron	% Copper	% Total
Light	1.60	0.05	1.65
Full	0.16	0.53	0.69
0.5 P.F.	0.32	1.06	1.38

**\*\*TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS\*\***

**SERIES TEST**

Test Load	% Iron	% Copper	% Total
Light	3.10	1.10	4.20
Full	0.31	10.96	11.27
0.5 P.F.	0.62	21.92	22.54



## Pro Forma Transformer and Line Loss Correction Worksheet

### TRANSFORMER AND LINE LOSS CORRECTION

Name:  
 Delivery:  
 Location:  
 Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

Compensation Values (@ 5A F.L.)		Compensation Values at: 10 A	
Watt Fe Loss:	%	Watt Fe Loss:	%
Watt Cu Loss:	%	Watt Cu Loss:	%
Watt Tot. Loss:	%	Watt Tot. Loss:	%
Var Fe Loss:	%	Var Fe Loss:	%
Var Cu Loss:	%	Var Cu Loss:	%
Var Tot. Loss:	%	Var Tot. Loss:	%

Comments:

#### TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current

Total kVa rating:	Max Available kVa:
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#### LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	miles
#2 Line Type:	Ohms/mile	miles
#3 Line Type:	Ohms/mile	miles
#4 Line Type:	Ohms/mile	miles
#5 Line Type:	Ohms/mile	miles
#6 Line Type:	Ohms/mile	miles

**Pro Forma Transformer and Line Loss Correction Worksheet  
 (continued)**

**TRANSFORMER AND LINE LOSS COMPENSATION**

Name:  
 Delivery:  
 Location:  
 Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

**TRANSFORMERS**

Serial Number	kVa
---------------	-----

**\*\*TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS\*\***

**SERIES TEST**

Test Load	% Iron	% Copper	% Total
Full			
0.5 P.F.			
Light			

**\*\*TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS\*\***

**SERIES TEST**

Test Load	% Iron	% Copper	% Total
Full			
0.5 P.F.			
Light			

## APPENDIX F

### INSTRUMENT TRANSFORMER RATIO AND CABLE LOSS CORRECTION FACTORS

#### **Background**

All current transformers (CTs) and voltage transformers (VTs) (collectively, instrument transformers) have inherent errors due to their design and the physical properties of the materials used in their construction. These errors are manifested as a magnitude and phase angle difference between the "ideal" nameplate ratio and the waveform actually present on the secondary of the transformer. The terms used to denote these errors are Ratio Correction Factor (RCF) and Phase Angle Correction Factor (PACF).

The burden (load) connected to instrument transformer secondaries has an effect on the RCF and PACF of the units. All wiring and instrumentation of any kind is part of the burden. On a CT, the burden is designated in ohms and is represented by a number ranging from B-0.1 through B-1.8. On a VT, burden is measured in volt-amps and indicated by an alpha character, such as W, X, M, Y, Z or ZZ. The magnitude of these burdens must be known and kept within specified limits or additional errors will occur in the metering.

Significant impedance in the leads between the VTs and the meter can be another source of error, where a voltage drop in the leads is caused by the load of the meter and any other connected devices between the VTs and the meter. Conductors which are too small or too long can cause metering error.

#### **Correction when the Burden Rating is exceeded**

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet minimum ISO accuracy requirements, then one of the actions listed below must to be taken:

- i. The preferred action is to correct the problem by either replacing the instrument transformer(s) with higher burden rated revenue class units or reducing the burden on the circuit to comply with the name plate of existing instrument transformer(s).

- ii. An acceptable action is to apply ISO approved correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The ISO Metered Entity will be responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meter to adjust for inaccuracies in the metering circuit. ISO approved algorithms and spreadsheets for calculating correction factors are included in this Appendix.

#### **CT Ratio Correction Factor**

Current transformers are usually tested by the manufacturer for the value of RCF and phase angle at both 5 and 0.5 amp secondary currents. The values for each CT in an installation would be averaged together to determine the CT Ratio Correction Factor (RCFI) and CT Phase Angle (b). If the current transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

#### **VT Ratio Correction Factor**

Voltage transformers are usually tested by the manufacturer for the value of RCF and phase angle at rated voltage. The values for each VT in an installation would be averaged together to determine the VT Ratio Correction Factor (RCFE) and VT Phase Angle (g). If the voltage transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

#### **Cable Loss Correction Factor**

The secondary voltage cables at an installation can be tested to determine the losses and phase angle of each. These values would then be averaged together to get the Cable Loss Correction Factor (CLCF) and the Phase Angle (a) for the installation. If the calculated connected burden of each phase do not exceed the VT burden rating, then the correction factors may be disregarded.

#### **Final Correction Factor**

The PACF for an installation is determined by the following formula:

$$PACF = \frac{\cos(Q + b - a - g)}{\cos Q}$$

Where  $\cos Q$  is the secondary apparent power factor.

The Final Correction Factor (FCF) can then be determined as follows:

$$\text{FCF} = \text{RCFI} * \text{RCFE} * \text{CLCF} * \text{PACF}$$

The Percent Error is the amount of error caused by the instrument transformers and cable loss, it is calculated as follows:

$$\text{Percent Error} = (1 - \text{FCF}) * (100)$$

The Percent Meter Adjustment is the adjustment to the meter required to compensate for the Percent Error, it is calculated as follows:

$$\text{Percent Adjustment Factor} = (\text{FCF} - 1) * (100)$$

The FCF is applied to the calibration of the meter, usually through adjustment of the calibration potentiometer or through a change in the programmed calibration values. After an adjustment to the meter is made, the meter should be tested at all test points to show that the meter is within calibration limits with the calibration values applied. A FCF which results in a correction of less than 0.6% can be disregarded since this is less than the required combined accuracy of the instrument transformers. However, if any correction factor (full load, light load or power factor) results in a correction of more than 0.6%, they should all be applied.

## Applications

### *Typical Installation*

The preferred meter installation would utilize revenue metering class instrument transformers (0.3 %) operated at or below rated burden. If this is not the case, one or more of the following actions may be used to correct the problem:

- Replace instrument transformers with higher burden rated units.
- Reduce the burden on the circuit to comply with the existing rated burden.
- Apply correction factors to the meter to compensate for inaccuracies.

### *Paralleling CTs*

In normal revenue metering, current transformers would not be paralleled, but there are some applications where paralleling is done because the cost of the installation is reduced and the possibility of reduced meter accuracy is acceptable. A typical installation of this type

would be to meter the net output of a generating station on a single meter rather than metering gross generator output and auxiliary power separately. In these type of installations additional rules apply:

- All of the transformers must have the same nominal ratio regardless of the ratings of the circuits in which they are connected.
- All transformers which have their secondaries paralleled must be connected in the same phase of the primary circuits.
- The secondaries must be paralleled at the meter and not at the current transformers.
- There should only be one ground on the secondaries of all transformers. This should be at their common point at the meter. Each utility may use their established grounding procedures.
- Modern current transformers with low exciting currents and, therefore, little shunting effect when one or more current transformers are "floating" at no load should be used. Three or more "floating" current transformers might have an effect that should be investigated.
- The secondary circuits must be so designed that the maximum possible burden on any transformer will not exceed its rating. The burden should be kept as low as possible as its effects are increased in direct proportion to the square of the total secondary current.
- A common voltage and frequency must be available for the meter.
- If adjustments are made at the meter to compensate for ratio and phase angle errors, the ratio and phase angle error corrections used must represent the entire combination of transformers as a unit.
- The watthour meter must be able to carry, without overload errors, the combined currents from all the transformers to which it is connected.
- While servicing meters and equipment on parallel CT secondaries, all CTs must be by-passed (shorted). When work is completed all by-passes must be removed.

### **Worksheets**

A worksheet which can be used to perform the above calculations is attached to this Appendix. Instructions for completing the worksheet follow:

- Complete the Name, Delivery and Location fields using the ISO Metered Entity's name, the operating name of the delivery, and the city and state for the location.

- Enter the values of RCF and phase angle as tested at full load and light load for each CT in the circuit. Record the manufacturer and serial number of each transformer.
- Enter the values of RCF and phase angle as tested at rated voltage for each VT in the circuit. Record the manufacturer and serial number of each transformer.
- Enter the values of the Cable Loss Correction Factor and Phase Angle for the secondary voltage cables.
- The worksheet will calculate the Final Correction Factors, Percent Errors and Percent Adjustment Factors to be applied to the meter calibration.

**Reference Materials**

The following additional reference may be referred to for assistance when calculating the correction factors referred to in this Appendix.

- Handbook For Electricity Metering, Ninth Edition. Edison Electric Institute. Washington, D.C.

### CT/VT Ratio and Cable Loss Correction Worksheet (Example)

Name:  
 Delivery:  
 Location:

Full Load	Light Load
-----------	------------

**CT Test Data:**

Phase 'A' CT		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>1</sup> )	1.0003	1.0002	
Phase Angle ( $\beta$ ) (minutes)	-0.3	2.2	

Phase 'B' CT		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>1</sup> )	1.0004	1.0029	
Phase Angle ( $\beta$ ) (minutes)	-0.4	2.2	

Phase 'C' CT		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>1</sup> )	1.0019	1.0028	
Phase Angle ( $\beta$ ) (minutes)	-0.3	3.1	

Average of CT's		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>1</sup> )	1.0009	1.0020	
Phase Angle ( $\beta$ ) (minutes)	-0.3	2.5	

**VT Test Data:**

Phase 'A' VT		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>5</sup> )	0.9997		
Phase Angle ( $\gamma$ ) (minutes)	1.5		

Phase 'B' VT		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>5</sup> )	0.9996		
Phase Angle ( $\gamma$ ) (minutes)	1.5		

Phase 'C' VT		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>5</sup> )	0.9997		
Phase Angle ( $\gamma$ ) (minutes)	1.7		

Average of VT's		Mfr. & Serial Number:	
Ratio Correction Factor (RCF <sup>5</sup> )	0.9997		
Phase Angle ( $\gamma$ ) (minutes)	1.6		

**Cable Loss Test Data:**

Phase 'A'			
Ratio Correction Factor (CLCF)	0.9969		
Phase Angle ( $\alpha$ ) (minutes)	4.3		

Phase 'B'			
Ratio Correction Factor (CLCF)	0.9949		
Phase Angle ( $\alpha$ ) (minutes)	4.2		

Phase 'C'			
Ratio Correction Factor (CLCF)	0.9959		
Phase Angle ( $\alpha$ ) (minutes)	4.7		

Average Cable Loss Data			
Ratio Correction Factor (CLCF)	0.9959		
Phase Angle ( $\alpha$ ) (minutes)	4.4		

**Correction Factors:**  
 Light Load

Full Load      Power Factor



CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION  
FERC ELECTRIC TARIFF  
ORIGINAL VOLUME NO. III

Original Sheet No. 1095

Avg. Combined Corr. Factor	0.9964	0.9964	0.9975
Phase Ang Corr Factor (PACF)	1.0003	1.0032	1.0001
Final Correction Factor (FCF)	0.9967	0.9996	0.9977
Percent Error	+ 0.33	+ 0.04	+ 0.23
Percent Meter Adjustment	- 0.33	- 0.04	- 0.23

Issued by: N. Beth Emery, General Counsel and Vice President  
Issued on: June 1, 1998

Effective: March 31, 1998

### CT/VT Ratio and Cable Loss Correction Worksheet

Name:  
 Delivery:  
 Location:

Full Load	Light Load
-----------	------------

**CT Test Data:**

Phase 'A' CT	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>1</sup> )			
Phase Angle ( $\beta$ ) (minutes)			

Phase 'B' CT	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>1</sup> )			
Phase Angle ( $\beta$ ) (minutes)			

Phase 'C' CT	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>1</sup> )			
Phase Angle ( $\beta$ ) (minutes)			

Average of CT's	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>1</sup> )			
Phase Angle ( $\beta$ ) (minutes)			

**VT Test Data:**

Phase 'A' VT	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>5</sup> )			
Phase Angle ( $\gamma$ ) (minutes)			

Phase 'B' VT	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>5</sup> )			
Phase Angle ( $\gamma$ ) (minutes)			

Phase 'C' VT	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>5</sup> )			
Phase Angle ( $\gamma$ ) (minutes)			

Average of VT's	Mfr. & Serial Number:		
Ratio Correction Factor (RCF <sup>5</sup> )			
Phase Angle ( $\gamma$ ) (minutes)			

**Cable Loss Test Data:**

Phase 'A'			
Ratio Correction Factor (CLCF)			
Phase Angle ( $\alpha$ ) (minutes)			

Phase 'B'			
Ratio Correction Factor (CLCF)			
Phase Angle ( $\alpha$ ) (minutes)			

Phase 'C'			
Ratio Correction Factor (CLCF)			
Phase Angle ( $\alpha$ ) (minutes)			

Average Cable Loss Data			
Ratio Correction Factor (CLCF)			
Phase Angle ( $\alpha$ ) (minutes)			

**Correction Factors:**  
 Light Load

Full Load      Power Factor

Avg. Combined Corr. Factor			
Phase Ang Corr Factor (PACF)			
Final Correction Factor (FCF)			
Percent Error			
Percent Meter Adjustment			

## **APPENDIX G**

### **ISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES**

This Appendix is provided for information purposes only, it gives an overview of the procedures that the ISO will use to validate, edit and estimate Meter Data received from ISO Metered Entities and, where an exemption applies, Meter Data received from SC Metered Entities.

#### **G 1            Validation**

##### **G 1.1        Timing of Data Validation**

Meter Data will be remotely retrieved via WEnet from ISO Metered Entities by MDAS on a daily basis. Validation will be performed on the new Meter Data as it is retrieved from the meter or Compatible Meter Data Server in order to detect:

- missing data;
- data that could be invalid based upon status information returned from the meter; or
- meter hardware or communication failure.

Additional validation will be performed on a daily basis to verify data against load patterns, check meters, schedules, MDAS load interval data and data obtained by SCADA.

##### **G 1.2        Data Validation Conditions**

MDAS will detect the following conditions so that erroneous data will not be used for Settlement or billing purposes:

##### **G 1.2.1     Validation of metering/communications hardware:**

- meter hardware/firmware failures;
- metering CT/VT failures (for example, losing one phase voltage input to the meter);
- communication errors;

- data which is recorded during meter tests;
- mismatches between the meter configuration and host system master files;
- meter changeouts (including changing CT/VT ratios);
- gaps in data;
- overflow of data within an interval;
- ROM/RAM errors reported by the meter; and
- alarms/phase errors reported by the meter.

**G 1.2.2 Validation of MDAS load Interval Data characteristics:**

- data which exceeds a defined tolerance between main and check meters;
- data which exceeds a defined tolerance between metering and SCADA data;
- load factor limits;
- power factor limits; and
- for End-Users, validation of load patterns against historical load shapes.

**G 1.3 Validation Criteria**

Validation criteria will be defined by the ISO for each channel of MDAS load interval data (kW/kVar/kVa/Volts, etc.) depending on the load characteristics for each meter location and the type of data being recorded.

For loads that do not change significantly over time or change in a predictable manner, percentage changes between intervals will be used.

For loads that switch from no-load to load and for reactive power where capacitors may be switched to control power factors, validation will be based upon historical data for that meter location. If no historical data is available, data such as the rating of transformers or the maximum output from a Generator will be used to set maximum limits on interval data.

Validation will be based upon reasonable criteria that can detect both hardware and operational problems with a high degree of confidence but will be set so as to avoid unnecessary rejection of data.

**G 1.4                    Validation for Stated Criteria**

Data validation will be performed only for the validation criteria that has been entered for each meter channel of data. For example, the number of intervals of zero Energy recorded by the meter for the channel indicated will be validated only when a non-zero value is entered for this criteria.

Additional validation will be performed on a daily basis to verify data which is based upon load patterns, comparisons to check meters, schedules, MDAS load profiles or data obtained by SCADA.

**G 1.5                    Validation Failure**

Data that fails validation will be flagged with the reason for the failure, where applicable. Data that fails checks such as load factor limits or comparisons of a MDAS load profile to the previous day, check meter or other load shape will be identified so that manual intervention can be used to estimate the correct values in order to edit the data or to manually accept the data.

**G 1.6 Validation Criteria**

**G 1.6.1 Time of Application of Criteria**

<b>Validation Criteria</b>	<b>Hourly</b>	<b>Daily</b>
<b>Meter Readings vs. MDAS load profile (Energy Tolerance)</b>		<b>Yes</b>
<b>Intervals Found vs. Intervals Expected</b>		<b>Yes</b>
<b>Time Tolerance Between MDAS and Meter</b>	<b>Yes</b>	<b>Yes</b>
<b>Number of Power Outage Intervals</b>		<b>Yes</b>
<b>Missing Intervals (Gap In Data)</b>		<b>Yes</b>
<b>High/Low Limit Check On Interval Demand</b>	<b>Yes</b>	<b>Yes</b>
<b>High/Low Limit Check on Energy</b>		<b>Yes</b>
<b>CRC/ROM/RAM Checksum Error</b>	<b>Yes</b>	<b>Yes</b>
<b>Meter Clock Error</b>	<b>Yes</b>	<b>Yes</b>
<b>Hardware Reset Occurred</b>	<b>Yes</b>	<b>Yes</b>
<b>Watchdog Timeout</b>	<b>Yes</b>	<b>Yes</b>
<b>Time Reset Occurred</b>	<b>Yes</b>	<b>Yes</b>
<b>Data Overflow In Interval</b>	<b>Yes</b>	<b>Yes</b>
<b>Parity Error (Reported By Meter)</b>	<b>Yes</b>	<b>Yes</b>
<b>Alarms (From Meter)</b>	<b>Yes</b>	<b>Yes</b>
<b>Load Factor Limit</b>		<b>Yes</b>
<b>Power Factor Limit</b>		<b>Yes</b>
<b>Main vs. Check Meter Tolerance</b>		<b>Yes</b>
<b>Actual vs Scheduled Profile</b>		<b>Yes</b>
<b>Actual vs SCADA Data</b>		<b>Yes</b>
<b>Comparison Of Current Day To Previous Day</b>		<b>Yes</b>
<b>Percent Change Between Intervals</b>		<b>Yes</b>

**G 1.6.2 Validation Criteria**

**(a) Meter Reading vs. MDAS load Interval Data (Energy Tolerance)**

Meter readings will be obtained from ISO approved meters on a daily basis in order to validate interval Energy measurements

obtained from the MDAS approved meters data and Energy from the meter readings. This Energy tolerance check will be used to detect meter changeouts or changes in metering CT/PT ratios that have not been reflected in the MDAS master files (meter configuration files). A "tolerance type" parameter will be set in the MDAS system parameter to define the type of check to be performed.

The types of check that will be used will include the following (the constant used to convert the meter readings to kWh):

ID	Term	Description
<b>M</b>	<b>Multiplier</b>	Allows a percentage of the meter multiplier difference between the meter reading the recorded interval total energy.
<b>P</b>	<b>Percent</b>	Allows a percentage of the metered total energy difference between the metered total energy and the recorded total energy. The percent of allowed difference will be defined by the ISO on an individual meter channel basis.
<b>Q</b>	<b>Same as Percent</b>	Based on 30 days of data. If the data relates to a period less than 30 days then the total usage will be projected to 30 days as follows:  Projected Usage=Total Usage * (30/Total Days)
<b>D</b>	<b>Dual Check</b>	Percent Method (P) is the primary check. If it fails, then the Multiplier Method (M) is used.
<b>E</b>	<b>Dual Method</b>	Percent Method (Q) is the primary check. If it fails, then the Multiplier Method (M) is used.
<b>N</b>	<b>None</b>	No tolerance check

**(b) Intervals Found vs Intervals Expected**

MDAS will calculate the expected number of time intervals between the start and stop time of the MDAS load profile data file and compare that number against the actual number of time intervals found in the MDAS data file. The calculation used to determine the expected number of time intervals will take into account the size or



duration of the actual time intervals for the particular meter/data file (e.g., 5 min, 15 min, 30 min and 60-min interval sizes).

**(c) Time Tolerance Between MDAS and Meter**

When MDAS retrieves data from a meter, the MDAS workstation clock will be compared against the meter's clock. MDAS will be configured to automatically update the meter clocks within certain tolerances, limits and rules including:

- i. a time tolerance parameter (in seconds) which indicates the allowable difference between the MDAS workstation clock and the meter clock (if the meter clock is within that parameter, MDAS will not update the meter clock);
- ii. an upper limit for auto timeset which is the maximum number of minutes a meter can be out of time tolerance before MDAS will perform an auto timeset;
- iii. the MDAS will not perform auto timesets across interval boundaries; and
- iv. the auto timeset feature will support DST changes and time zone differences. Since all ISO Metered Entity's meters that are polled by MDAS will be set to PST, this rule will not generally apply.

**(d) Number of Power Outage Intervals**

The ISO approved meter will record a time stamped event for each occurrence of a loss of AC power and a restoration of AC power. During the Meter Data retrieval process, MDAS will flag each MDAS interval between occurrences of AC power loss and AC power restoration with a power outage status bit. MDAS will sum the total number of power outages for a time frame of MDAS data and compare that value against an ISO defined Power Outage Interval Tolerance value stored in the MDAS validation parameters.

**(e) Missing Intervals (Gap in Data)**

The MDAS validation process will compare the stop and start times of two consecutive pulse data files for a meter and will report if a missing interval/gap exists. The MDAS automatic estimation process for "plugging" missing intervals/gaps in data is described in more detail in the Data Estimation section of this Appendix.

**(f) High/Low Limit Check on Interval Demand**

The MDAS validation process will compare the Demand High/Low Limits entered by the MDAS operator on a meter channel basis in the MDAS meter channel table against the actual Demand value collected from the meter. This comparison will be performed on an interval by interval basis. If the actual Demand value is less than the Low Limit or greater than the High Limit, the MDAS validation process fails.

**(g) High/Low Limit Check on Energy**

The MDAS validation process compares the Energy High/Low Limits entered by the MDAS operator on a meter channel basis in the MDAS meter channel table against the actual total Energy collected from the meter for the time period. If the actual total Energy is less than the Low Limit or greater than the High Limit, the MDAS validation process fails.

**(h) CRC/ROM/RAM Checksum Error**

This general meter hardware error condition can occur during an internal status check or an internal read/write function within the meter. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available, this internal status information will be collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

**(i) Meter Clock Error**

This meter hardware error condition can occur whenever an internal meter hardware clock error results in an invalid time, day, month, year, etc. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available this interval status information is collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

**(j) Hardware Reset Occurred**

This meter hardware error condition occurs whenever an internal meter hardware reset occurs. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available this interval status information is collected

during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

**(k) Watchdog Timeout**

This error code may not be standard on some meters (reference should be made to the meter's user manual). When available, this feature watches for meter inactivity, indicating a possible meter failure.

**(l) Time Reset Occurred**

This is a meter error code that indicates that the meter time has been reset. See paragraph (c) above.

**(m) Data Overflow In Interval**

This error code occurs when the amount of data in an interval exceeds the memory capabilities of the meter to store the data. This alerts MDAS that there is corrupt data for the interval.

**(n) Parity Error (Reported by Meter)**

Parity error is another indicator of corrupted data.

**(o) Alarms (From Meter)**

ISO MDAS operator will evaluate all meter alarms to determine if the alarm condition creates data integrity problems that need to be investigated.

**(p) Load Factor Limit**

The MDAS validation process compares the daily Load Factor to the limit entered by the MDAS operator. MDAS will prompt the operator to investigate data integrity if the limit is out of tolerance.

**(q) Power Factor Limit**

The MDAS validation process compares the actual Power Factor to the limit entered by the MDAS operator. MDAS will prompt the operator to investigate if the limit is out of tolerance.

**(r) Main vs Check Meter Tolerance**

The main and check meters can be configured in MDAS to be compared on a channel by channel basis to the check meter ID, channel number, percent tolerance allowance and the type of check. Interval or daily Meter Data will be entered into the corresponding main meter MDAS meter channel table record. This information will remain constant unless:

- i. a meter changeout occurs at the site;

- ii. the percent tolerance allowance needs adjusting;  
and/or
- iii. the type of check is switched.

If the percentage difference between the main channel interval Demand and the check channel interval Demand exceeds the Percent Tolerance allowed, the MDAS validation will fail. If, after applying this validation test, the percentage difference between the main channel total Energy and the check channel total Energy for each Trading Day exceeds the allowed percentage, the MDAS validation will fail. In both cases, if the percentage difference is less than the Percent Tolerance allowed, the MDAS validation will be accepted.

**(s) Actual vs. Scheduled Profile**

Data is compared on an interval by interval basis like Main vs Check.

**(t) Actual vs. SCADA Data**

Data is compared on an interval by interval basis like Main vs Check.

**(u) Comparison Of Current Day To Previous Day**

The MDAS validation process compares the last complete day's Demand and Energy in the validation time period to one of the following parameters configured by the MDAS operator:

- i. previous day;
- ii. same day last week; or
- iii. same day last month.

**Validation Failure**

If the percentage difference between the Demand and Energy exceeds the tolerance setup in the MDAS validation parameters, the data subjected to the validation process fails.

**(v) Percent Change Between Intervals**

The MDAS validation process uses the Interval Percent Change Tolerance set by the MDAS operator on a meter channel basis in the MDAS meter channel table to compare the percentage change in the pulses for the channel between two consecutive intervals. If the percent change exceeds the Interval Percent Change Tolerance set for that channel, the MDAS validation process fails.

**G 2 Data Estimation Criteria**

When interval data is missing due to there not being any response from the meter or the meter reports it as missing, MDAS will supply

estimated data for the missing intervals based on the guidelines discussed below.

If a certified Check Meter is available and that data is valid, the data from the Check Meter will be used to replace the invalid or missing data from the main meter. When reading meters on a frequency basis, the point-to-point linear interpolation method will be used to estimate the current interval(s) of data. This method will only normally be used when estimating one hour or less of contiguous missing interval data when the previous and next intervals are actual values from the meter. If data is missing for an extended time period, historical data will be used as the reference date so that data can be matched to time of day and day of week.

**G 2.1 Data Estimation Methods**

The following data estimation methods are configurable by the MDAS operator on a meter-by-meter basis. The algorithms for each method are described below in order of precedence as implemented by the MDAS automatic estimation application software. The MDAS operators can alter this order by simply not activating a certain method. In addition, the MDAS operator can manually select each data estimation method at any time during the data analysis process.

**G 2.2 Main vs Check Meter**

The global primary and Check Meters can be configured in the MDAS meter channel table to be compared on a channel-by-channel basis. The Check Meter ID and channel number will be entered into the corresponding primary meter MDAS meter channel table record. This information remains constant unless a meter changeout at the site occurs. During the MDAS automatic estimation process, if missing data is encountered and actual values from a certified Check Meter are available, the values for the corresponding intervals from that Check Meter will be substituted into the data file for the primary meter. All copied intervals will be tagged as an edited interval. In order for actual values from the check meter to be deemed acceptable for use in the automatic estimation process, the values must reside in an accepted data file that passed the validation criteria referred to earlier in this Appendix and no error codes or alarms can be set on the interval values. Meter Data from Check Meters may only be used where Meter Data is not available from the primary meter.

**G 2.3 Point-to-Point Linear Interpolation**

When reading meters on a frequency basis, the Point-to-Point Linear Interpolation Algorithm described below can be used to estimate the missing intervals of data. This method will only normally be used to

estimate a maximum of one hour of contiguous missing interval data when the previous and next intervals are actual values from the meter. Even though this method will not normally be used above that maximum of one hour, the MDAS allows this maximum threshold to be set by the MDAS operator on a meter-by-meter basis. The same rules for defining acceptable actual values apply as detailed in Main vs. Check Meter description above. All estimated intervals will be tagged as an edited interval.

*Point to Point Linear Interpolation Algorithm*

$$\text{Estimated Interval} = \frac{\text{Next Actual} - \text{Previous Actual Interval}}{\text{Number of Missing Intervals} + 1} + \text{Previous Actual Interval}$$

**G 2.4 Historical Data Estimation**

Historical data estimation is the process of replacing missing or corrupt interval data in the MDAS data files. The data is replaced using historical data as a reference. There are two basic requirements when estimating data to be inserted or replaced:

- the amount of data to add or replace; and
- the shape or contour of the data over the time span requested.

**G 2.4.1 Estimation Parameters**

The following estimation parameters are required on a per meter basis:

Auto Plug (Y/N) Controls the option to perform automatic estimation

Auto Plug Option (W/C/P/L) Indicates where to get the reference data used in the estimation process:

W - use the previous week as the reference data (all data for the week must be present).

C - use the current month as reference data.

P - use the previous month as reference data.

L - use the current month of last year as reference data.

Reference ID ID from which the reference data is retrieved. The contour of the data is determined from this ID. The Reference ID can be the same as the meter ID (i.e. use historical data from the

same meter) or a different Reference ID.

Auto Plug Missing Days Limit Verifies that the number of missing days of data is less than the missing day limit in order to invoke automatic estimation.

Auto Plug Reference Data % Identifies a percent adjustment for situations where there is a need to factor the reference data by a percent increase or decrease. If this value is set to "0", the adjustment is not performed.

Auto Plug Power Outage Indicates if intervals with a power outage status are to be estimated/replaced automatically.

Reference Time Span Identifies the reference time span for the historical data.

**G 2.4.2 Total Data**

The estimation algorithm used depends on the total amount of data to be added or replaced and the shape of that data. The MDAS operator can give the total data or that can be calculated to balance the meter usage in the file. The shape of the data is defined with the use of the reference data.

**G 2.4.3 Reference Data**

The reference data is based on the day of the week. All reference data is averaged and stored into a 7-day table of values for each interval. The table includes a day's worth of intervals for each day of the week (Sunday-Saturday). When the shape of a day's data is needed, this weekly table is referenced. Two data tables are set up to use in the algorithm. One stores the number of times that an

interval value is needed from the reference data. While the other table maps the interval value in the reference data to the correct data in the update file. The data from the reference must be scaled up or down to match the magnitude of the data needed for the update file. This is determined by comparing the data total from the reference file with the data needed for the update file. This ratio is used when getting reference data to use for the update file.

#### **G 2.4.4 Iterations**

Iterations will be used to get the best reproduction of data in the update file. This process will attempt to get the correct shape for the data and also to get as close to the requested total data as possible by using up to ten iterations. Since MDAS data will be integer data and cannot have decimal values, the total data used will not be exactly what is requested. Definition of some of the tables and variables are:

REFTOT	Total data from the reference file for the time requested.
REQTOT	Total requested data.
REFADJ	Adjusted total reference data.
IP( )	A table containing the total times that a value is used from the reference data.
NP ( )	A table containing the data in the update file for that value in the reference data. A table mapping the reference data to the update data according to the needed ratio.

#### **G 2.4.5 Population of Tables**

The first step is to populate the tables. All intervals for the requested time are read from the reference data. These values are stored into table NP( ). The number of times a value is used is stored into the table IP( ). For example:

If the value 54 is needed 3 times, then  $IP(54)=3$  and  $NP(54)=54$

The table IP( ) is used to quickly add up the totals. The table NP( ) is modified by the ratio  $REQTOT/REFADJ$ . For example:

If:             $REQTOT=22000$   
                   $REFTOT=44000$

Then:           $REQTOT/REFTOT=0.50$

and             $NP(54) = 0.50 * NP(54) = 27$



After modifying the complete NP( ) table, the total data is added to determine how close this total is to the requested total (REQTOT). The NP( ) values have to be rounded to whole numbers. This total is calculated by adding up all of the values in the NP ( ) table multiplied by the times the value is needed (IP( )). Each value used (IP(x) not zero) is multiplied by the value (NP(x)). Then each of the results is added up to a total. If the total is close enough to the requested total then the iteration process ends. After ten iterations the total will automatically be considered close enough to the requested total.

**G 2.4.6 Update File**

As the data is needed to insert into the update file, the reference data is read from the reference file. The mapping table (NP) modifies the value. This modified value is inserted into the update file. All intervals are inserted in this manner to complete the data estimation.

**G 3 Editing**

All estimated intervals will be tagged as an edited interval in MDAS. The ISO MDAS operator will notify the Metered Entity of the edited interval start and stop times, new value and technique used to estimate the data.

If estimation and editing is frequently required for the Meter Data received from a particularly metered entity, the ISO may require re-certification and or facility maintenance or repair to correct the continued provision of erroneous or missing data.