ISO TARIFF APPENDIX O

Metering

PART 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 Scheduling Coordinators 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 Scheduling Coordinators using voice communications; and

(b) inform ISO Metered Entities and Scheduling Coordinators 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 Scheduling Coordinators via the WEnet.

PART B

CERTIFICATION PROCESS FOR METERING FACILITIES

Paragraphs B1 to B3 of this Part 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 Scheduling Coordinator Metered Entities where no certification requirements are imposed on a Scheduling Coordinator Metered Entity by its Local Regulatory Authority.

Paragraph B5 of this Part 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/Scheduling Coordinator Metered Entity

The ISO Metered Entity or Scheduling Coordinator 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 Scheduling Coordinator 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 Part) 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 Scheduling Coordinator 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 Scheduling Coordinator 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 Appendix, the ISO shall provide written notice of the deficiencies to the ISO Metered Entity or Scheduling Coordinator 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 10.3.18.5.1 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 Scheduling Coordinator Metered Entity is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Appendix; 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 Section 10.2.4.1, 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 Part; 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.

ISO Meter Certification Form	
Facility Information	
Name:	Unit Name:
Address:	Drawing Numbers: (see note 1)
ISO Metered Entity Contact :	Phone Number:
Scheduled ISO Inspection Date:	

Generator Information			
Gross Output		Auxiliary Load	
Net Output		Voltage / Connections	

Revenue Billing Information			
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 ☐ (info. is attached) No ☐

Internal Mass Memory Constants					
Function	Channel	K_e	PRI KWH Constant	Interval Size	Display Sequence
KWH DELIVERED					
KVARH DEL					
KVARH REC					
KWH RECEIVED					

Voltage Transformer Information				**Current Transformer Information**			
Name Plate	**A**	**B**	**C**	Name Plate	**A**	**B**	**C**
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 ☐Fail ☐	Pass ☐Fail ☐	Pass ☐Fail ☐

Instrument Transformer Correction Factors (FCF) (see note 2)		
Full Load	**Power Factor**	**Light Load**
Line Loss Compensation Values (at Full Load Meter Rating) (see note 2 and 3)		
% Watt Fe Loss	% Var Fe Loss	
% Watt Cu Loss	% Var Cu Loss	
Total Compensation Values (at Full Load Meter Rating)		
% Watt Total Loss	% Var Total Loss	
Completed by:		Date:
Remarks:		
Reviewed by:		Date:

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 Part.
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.

PART 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 Part D of this Appendix.

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 Appendix 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 Appendix 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).

PART D

STANDARDS FOR METERING FACILITIES

The standards for Metering Facilities referred to in this Part 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 Part apply to ISO Metered Entities and, where the relevant Local Regulatory Authority has not set any standards, to Scheduling Coordinator 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 Part, the detailed standards shall prevail.

D 3 Detailed Standards for New Meters

Exhibit 1 to this Part 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 Part 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 PART D

SPECIFICATION MTR1-96

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

TABLE OF CONTENTS

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 an 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 it's 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. ± 0.2% at Full load at power factor of 100%;

ii. ± 0.25% at Full load at power factor of 50% lag;

iii. ± 0.25% at Full load at power factor of 50% lead; and

iv. ± 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% ±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°±2° 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 ±2° Celsius.

Attachment 1

Physical and Electronic Attribute Criterion for Electricity Meters

	Test / Inspection Description	Pass	Fail
1.	**Bayonets**		
A.	Missing or loose parts, i.e., cotter pin, arc gap, etc.		
2.	**Meter Base**		
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		
3.	**Meter Frame**		
A.	Nameplate data incorrect or flawed		
B.	Missing or loose hardware on frame		
4.	**Module**		
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)		
5.	**Meter Cover**		
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		

Attachment 1

Physical and Electronic Attribute Criterion for Electricity Meters (cont.)

6. Electronic Register		
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

Display Item	Normal Mode	Alternate Mode	Test Mode
Minimum Requirements for Delivered kWh			
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.)

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

Additional requirements for kVAh (cont.)			
Previous Season Total Delivered kVAh		x	
Previous Season Total Received kVAh		x	
Total Delivered kVAh		x	
Total Received kVAh		x	
Additional requirements for Power Factor (if specified)			
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 PART 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:

Voltage (nominal kV)	Creepage (inches)	Strike (inches)
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).

PART 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 hystersis 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*).

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

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 Part. 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 Part.

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

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:

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			

PART 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 Part.

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 *cosQ* is the secondary apparent power factor.

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

FCF = RCFI * RCFE * CLCF * PACF

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

Percent Error = (1-FCF)*(100)

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

Percent Adjustment Factor = (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 Part. 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 Part.

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^I)	1.0003	1.0002
Phase Angle (β) (minutes)	-0.3	2.2

Phase 'B' CT   Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0004	1.0029
Phase Angle (β) (minutes)	-0.4	2.2

Phase 'C' CT   Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0019	1.0028
Phase Angle (β) (minutes)	-0.3	3.1

Average of CT's   Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0009	1.0020
Phase Angle (β) (minutes)	-0.3	2.5

VT Test Data:

Phase 'A' VT   Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9997

Phase Angle (γ) (minutes)	1.5

Phase 'B' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9996
Phase Angle (γ) (minutes)	1.5

Phase 'C' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9997
Phase Angle (γ) (minutes)	1.7

Average of VT's Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9997
Phase Angle (γ) (minutes)	1.6

Cable Loss Test Data:

Phase 'A'

Ratio Correction Factor (CLCF)	0.9969
Phase Angle (α) (minutes)	4.3

Phase 'B'

Ratio Correction Factor (CLCF)	0.9949
Phase Angle (α) (minutes)	4.2

Phase 'C'

Ratio Correction Factor (CLCF)	0.9959
Phase Angle (α) (minutes)	4.7

Average Cable Loss Data

Ratio Correction Factor (CLCF)	0.9959
Phase Angle (α) (minutes)	4.4

Correction Factors:	Full Load	Power Factor	Light Load
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

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^I)		
Phase Angle (β) (minutes)		

Phase 'B' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Phase 'C' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Average of CT's Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

VT Test Data:

Phase 'A' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	

Phase Angle (γ) (minutes)	

Phase 'B' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

Phase 'C' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

Average of VT's Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

Cable Loss Test Data:

Phase 'A'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Phase 'B'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Phase 'C'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Average Cable Loss Data

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Correction Factors:	Full Load	Power Factor	Light Load
Avg. Combined Corr. Factor			
Phase Ang Corr Factor (PACF)			
Final Correction Factor (FCF)			
Percent Error			
Percent Meter Adjustment			

PART G

ISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES

This Part 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 Scheduling Coordinator 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

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

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
M	**Multiplier**	Allows a percentage of the meter multiplier difference between the meter reading the recorded interval total energy.
P	**Percent**	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.
Q	**Same as Percent**	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)
D	**Dual Check**	Percent Method (P) is the primary check. If it fails, then the Multiplier Method (M) is used.
E	**Dual Method**	Percent Method (Q) is the primary check. If it fails, then the Multiplier Method (M) is used.
N	**None**	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 Part.

(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 Part 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

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

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 replacing 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 then 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 REQROT/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.

ISO TARIFF APPENDIX P

ISO Department of Market Analysis and Market Surveillance Committee

ISO TARIFF APPENDIX P

ISO Department of Market Analysis and Market Surveillance Committee

1 ISO DEPARTMENT OF MARKET ANALYSIS

1.1 Establishment

There shall be established on or before ISO Operations Date within the ISO a Department of Market Analysis that shall be responsible for the ongoing development, implementation, and execution of the ISO Market monitoring and information scheme described in this Tariff and the adherence to its objectives, as set forth in Section 38.1.

1.2 Composition

The Department of Market Analysis shall be adequately staffed by the ISO with full-time ISO staff with the experience and qualifications necessary to fulfill the functions referred to in this ISO Tariff. Such qualifications may include professional training pertinent to and experience in the operation of markets analogous to ISO Markets, in the electric power industry, and in the field of competition and antitrust law, economics and policy. The Department of Market Analysis shall be under the general management of the ISO CEO, provided that the CEO may designate another ISO officer (currently the General Counsel) for day-to-day oversight of the Department.

1.3 Accountability and Responsibilities

1.3.1 Department of Market Analysis

The Department of Market Analysis shall report to and be accountable to the ISO CEO and his or her designee on all matters pertaining to policy and other matters that may affect the effectiveness and integrity of the monitoring function, including matters pertaining to market monitoring, information development and dissemination and pertaining to generic or entity-specific investigations, corrective actions or enforcement.

1.3.2 CEO and MSC

The ISO CEO and the MSC shall each have the independent authority to refer any of the matters referred to in Section 37.3.3.1 to the ISO Governing Board for approval of recommended actions.

1.3.3 Chief Executive Officer (CEO)

1.3.3.1 The Department of Market Analysis shall report to and be accountable to the ISO CEO and his or her designee on all matters relating to administration of the Department and the internal resources and organization of the ISO in accordance with Appendix P, Section 1.3.3.2.

1.3.3.2 The ISO, through its CEO and Governing Board, shall determine that the Department of Market Analysis has adequate resources and full access to data and the full cooperation of all parts of the ISO organization in developing the database necessary for the effective functioning of the Department of Market Analysis and the fulfillment of its monitoring function.

1.3.4 Regulatory and Antitrust Enforcement Agencies

Where considered necessary and appropriate, or where so ordered by the regulatory or antitrust agency with jurisdiction over the matter in question, or by a court of competent jurisdiction, the ISO shall refer a matter to the regulatory or antitrust enforcement agency concerned, e.g., in cases of serious abuse requiring expeditious investigation or action by the agency. In all such cases of direct referral, the ISO CEO shall promptly inform the ISO Governing Board and the MSC of the fact of and the content of the referral.

1.3.5 Complaints

Any Market Participant, or any other interested entity, may at any time submit information to or make a complaint to the Department of Market Analysis concerning any matter that it believes may be relevant to the Department of Market Analysis's monitoring responsibilities. Such submissions or complaints may be made on a confidential basis in which case the Department of Market Analysis shall preserve the confidentiality thereof. The Department of Market Analysis, at its discretion, may request further information from such entity and carry out any investigation that it considers appropriate as to the concern raised. The Department of Market Analysis shall periodically make reports to the ISO CEO and ISO Governing Board on complaints received.

ISO TARIFF APPENDIX P1

ISO Department of Market Analysis

P1.1 ISO Department of Market Analysis

P1.1.1 Information Gathering and Market Monitoring Indices for Evaluation

P1.1.1.1 Information System

The Department of Market Analysis shall be responsible for developing an information system and criteria for evaluation that will permit it to effectively monitor the ISO Markets to identify and investigate abuses of that market, whether caused by exercises of market power or by other actions or inactions.

P1.1.1.2 Data Categories

To develop the information system set forth in Section P1.1.1.1, the Department of Market Analysis shall initially develop, and shall refine on the basis of experience, a detailed catalog of all the categories of data it will have the means of acquiring, and the procedures it will use (including procedures for protecting confidential data) to handle such data.

P1.1.1.3 Catalog of Market Monitoring Indices

The Department of Market Analysis shall initially develop, and shall refine on the basis of experience, a catalog of the ISO Market monitoring indices that it will use to evaluate the data so collected.

P1.1.2 Evaluation of Information

P1.1.2.1 Ongoing Evaluation

The Department of Market Analysis shall evaluate and reevaluate on an ongoing basis the data categories and market monitoring indices that it has developed under Appendix P1, Sections P1.1.1.2 and P1.1.1.3, and the information it collects and receives from various other sources, including and in particular the ISO's operation of the ISO Markets. Such ongoing evaluations shall provide the basis for its reporting and publication responsibilities as set forth in this ISO Tariff, for recommendations on proposed changes to the ISO Tariff and ISO Protocols and other potential rules affecting the ISO Markets, and for the development of criteria or standards for the initiation of proposed corrective or enforcement actions. In evaluating such information, the Department of Market Analysis may consult the MSC or such external bodies as may be appropriate.

P1.1.2.2 Submission of Evaluation Results

The final results of the Department of Market Analysis's ongoing evaluations under Appendix P1, Section P1.1.2.1 shall routinely and promptly be submitted to the ISO CEO and to the MSC for comment.

P1.1.3 Review of Rules of Conduct

The Department of Market Analysis shall review Rules of Conduct for their effectiveness and consistency with its market monitoring activities and standards. The Department of Market Analysis may at that time, and from time to time thereafter based on its experience in monitoring the ISO Markets, propose to the ISO CEO and/or the ISO Governing Board that changes be made in such Rules of Conduct.

P1.1.4 Reports and Recommendations

P1.1.4.1 ISO CEO and Governing Board

On the basis of the evaluation conducted under Appendix P1, Section P1.1.2 or the review conducted under Section 37.4.3, the Department of Market Analysis shall prepare periodic reports, as required by the ISO CEO, and specific ad hoc reports as appropriate, for the ISO CEO and ISO Governing Board on the state of competition in or the efficiency of the ISO Markets; and on its monitoring activities, the results of its evaluation and review activities, and its development and implementation of recommendations. Where appropriate, the ISO Department of Market Analysis may recommend to the ISO CEO and/or the ISO Governing Board actions to be taken, including the amendment of the ISO Tariff and ISO Protocols and corrective or enforcement action against specific entities. Such reports shall be made not less frequently than quarterly in the case of the ISO CEO and annually in the case of the ISO Governing Board and shall contain such information and be in such form as specified by such entities. Such reports shall be made public and publicized as specified by such entities except to the extent that they contain confidential or commercially sensitive information or to the extent such entities determine that effective enforcement of the monitoring function dictates otherwise.

P1.1.4.2 Regulatory Agencies

As required in the ISO Tariff or by the ISO CEO and ISO Governing Board, or as required by the regulatory agency with jurisdiction over the matters in question, the Department of Market Analysis shall prepare reports to the FERC and other regulatory agencies, which shall be reviewed and approved by the ISO CEO or his or her designee and then submitted as required. When publicly available reports are made to one regulatory agency with competent jurisdiction, such as the FERC, the Department of Market Analysis may simultaneously make such reports available to other regulatory agencies with legitimate interests in their contents, such as the Electricity Oversight Board, the California Public Utilities Commission, the California Energy Commission and/or the California Attorney General.

P1.1.4.3 ISO Market Surveillance Committee

All reports and recommendations to be made to regulatory agencies under Appendix P1, Section P1.1.4.2, unless urgency requires otherwise, shall first be submitted to the MSC for comments, which comments shall be reflected in any submittal to the ISO Governing Board seeking approval of any such reports or recommendations. All final reports made to external regulatory agencies shall be simultaneously submitted to the MSC.

P1.1.5 Market Participants

P1.1.5.1 Collection of Data

The Department of Market Analysis may request that Market Participants or other entities whose activities may affect the operation of the ISO markets submit any information or data determined by the Department of Market Analysis to be potentially relevant. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by Market Participants to provide such data shall be treated under Section 37. In the event of failures by other entities to provide such data, the ISO may take whatever action is available to it and appropriate for it to take, including reporting the failure to the pertinent regulatory agency, after providing such entity the opportunity to respond in writing as to the reason for the alleged failure and may include possible exclusion from the ISO Markets or termination of any relevant ISO agreements or certifications. Before any such action is taken, the ISO Participant shall be provided the opportunity to respond in writing as to the reason for the alleged failure.

P1.1.5.2 Dissemination of Data

Any Market Participant may request that the ISO provide data that the ISO has collected concerning that Market Participant; and, such data may, subject to constraints on the ISO's resources and at the ISO's sole discretion, be provided by the ISO subject to due safeguards to protect confidential and commercially sensitive data. Where such activity imposes a significant burden or expense on the ISO, the data may be provided on the condition that a reasonable contribution to the cost incurred by the ISO is made to the ISO by the requesting party.

P1.1.6 External Consulting Assistance and Expert Advice

In carrying out any of its responsibilities under this ISO Tariff, including the development of an information system, market monitoring indices and evaluation criteria, and the catalogs associated therewith, and in its analysis and ongoing evaluation of these catalogs and of the Rules of Conduct, the Department of Market Analysis may hire consulting assistance subject to the budgetary approval of the ISO CEO and may seek such expert external advice as it believes necessary.

P1.1.7 Liability for Damages

As provided in Section 14 of the ISO Tariff, the Department of Market Analysis, the MSC, the ISO CEO and other ISO staff, and the ISO Governing Board shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this ISO Tariff.

ISO TARIFF APPENDIX P2

Market Surveillance Committee

P2.2 Market Surveillance Committee

P2.2.1 Establishment

There shall be established on or before ISO Operations Date a Market Surveillance Committee (MSC), whose role it shall be to provide independent external expertise on the ISO market monitoring process and, in particular, to provide independent expert advice and recommendations to the ISO CEO and Governing Board. Members of the Committee shall not be, and shall not be understood to be, employees or agents of the ISO.

P2.2.2 Composition

P2.2.2.1 Qualifications

The MSC shall comprise a body of three or more independent and recognized experts whose combined professional expertise and experience shall encompass the following:

(a) economics, with emphasis on antitrust, competition, and market power issues in the electricity industry;

(b) experience in operational aspects of Generation and transmission in electricity markets;

(c) experience in antitrust or competition law in regulated industries; and

(d) financial expertise relevant to energy or other commodity trading.

P2.2.2.2 Criteria for Independence

Each member of the MSC must meet the following criteria for independence:

P2.2.2.2.1 no material affiliation, through employment, consulting or otherwise, with any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct; and

P2.2.2.2.2 no material financial interest in any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct.

P2.2.2.2.3 during their time on the Committee, members may not provide paid expert witness testimony or other commercial services to the ISO or to any other party in connection with any legal or regulatory proceeding relating to the ISO or any trade or other transaction involving the ISO markets (except that the Committee may consult with and make recommendations concerning the functioning of the markets to ISO Management or the ISO Governing Board in connection with legal or regulatory proceedings).

P2.2.3 Appointments to the MSC

For each position on the MSC, the ISO CEO shall conduct a thorough search and requisite due diligence to develop a nomination to the ISO Governing Board, which nomination shall be consistent with meeting the combined professional expertise and experience of the MSC set forth in Appendix P2, Section

P2.2.2.1 and with the criteria for independence set forth in Appendix P2, Section P2.2.2.2. The ISO Governing Board shall expeditiously consider such nominations. If the nomination is approved, the ISO

CEO shall appoint the candidate so nominated to the MSC. If the nomination is rejected, the ISO CEO shall expeditiously proceed to develop another nomination.

P2.2.4 Compensation and Reimbursements

Members of the MSC shall be compensated on such basis as the ISO Governing Board shall from time to time determine.

Members of the MSC shall receive prompt reimbursement for all expenses reasonably incurred in the execution of their responsibilities under this Appendix P2, Section P2.2.

P2.2.5 Liability for Damages

As provided in Section 14 of the ISO Tariff, the Department of Market Analysis, the MSC, the ISO CEO and other ISO staff, and the ISO Governing Board shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this ISO Tariff.

P2.2.6 SPECIFIC FUNCTIONS OF MARKET SURVEILLANCE COMMITTEE (MSC)

P2.2.6.1 Information Gathering and Evaluation Criteria

The MSC shall review the initial catalogs of information and data and of evaluation criteria developed by the Department of Market Analysis pursuant to Appendix P1, Section P1.1 and shall propose such changes, additions or deletions to such catalogs or items therein as it sees fit. In so doing, the MSC shall have full discretion to specify database items or evaluation criteria for inclusion in the pertinent catalog.

P2.2.6.2 Evaluation of Information

The MSC may, upon request of the Department of Market Analysis, the ISO Management or the ISO Governing Board, or on its own volition, evaluate such information or data, including as may be collected by the Department of Market Analysis on the basis of the evaluation criteria developed by the Department of Market Analysis or on such further articulated evaluation criteria developed by the MSC.

P2.2.6.3 Reports and Recommendations

P2.2.6.3.1 Required Reports

All evaluations carried out by the MSC pursuant to Appendix P2, Section P2.2.6.2, and any recommendations emanating from such evaluations, shall be embodied by the MSC in written reports to the ISO CEO and ISO Governing Board and shall be made publicly available subject to due restrictions on dissemination of confidential or commercially sensitive information. The MSC may submit any MSC report to FERC, subject to due restrictions on dissemination of confidential or commercially sensitive information.

P2.2.6.3.2 Additional Reports

The MSC may make such additional reports and recommendations as it sees fit relating to the monitoring program referred to in this ISO Tariff, the analysis of information, the evaluation criteria or any corrective or enforcement actions proposed by the Department of Market Analysis or proposed of its own volition.

P2.2.6.4 Publication of Reports and Recommendations

Upon request of the MSC, the ISO shall publish reports and recommendations of the MSC or incorporate them, if consistent, into the ISO's own reports or recommendations.

P2.2.7 IMPLEMENTATION OF RECOMMENDATIONS

P2.2.7.1 Plan and Rules of Conduct Changes

Following a recommendation of the MSC, the ISO Governing Board may make such changes as it believes are appropriate to the ISO Tariff, any ISO Protocol or Agreement, or any Rules of Conduct applicable in accordance with Sections 14.1.1 and 4.9 of this Tariff. .

P2.2.7.2 Tariff Changes

Upon recommendation of the MSC, the ISO Governing Board shall consider and may adopt proposed ISO Tariff changes in accordance with Section 14.1.1 of this Tariff.

P2.2.7.3 Sanctions and Penalties

Upon recommendation of the MSC, the ISO may impose such sanctions or penalties as it believes necessary and as are permitted under the ISO Tariff and related protocols approved by FERC; Section 37.9 or it may make any such referral to such regulatory or antitrust agency as it sees fit to recommend the imposition of sanctions and penalties.

P2.2.8 PUBLICATION OF INFORMATION

P2.2.8.1 Market Monitoring Data and Indices

The ISO Department of Market Analysis shall, pursuant to Appendix P1**,** Section P1.1.1, develop a catalog of data and indices. Upon approval of the ISO CEO, such catalogs shall be duly published on the ISO Home Page and disseminated to all Market Participants.

P2.2.8.2 Reports to Regulators

The ISO shall develop annual reports of market performance for delivery to FERC, and such other reports as may be required by FERC, which shall be submitted for review to the MSC. The Department of Market Analysis shall prepare and submit such reports to the ISO CEO, ISO Governing Board and to the regulatory agency concerned.

ISO TARIFF APPENDIX P

Attachment A

Conduct Warranting Mitigation

ISO Market Monitoring Plan

Market Mitigation Measures

1 PURPOSE AND OBJECTIVES

1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Real Time Market while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

1.2 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Attachment A:

“Economic Market Clearing Prices” are the Market Clearing Prices for a particular resource at the location of that particular resource at the time the resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-Ahead Energy market, the Hour-Ahead Energy market (when these markets are in place), or ISO real-time Imbalance Energy market. The Economic Market Clearing Price for the ISO real-time Imbalance Energy market shall be the Dispatch Interval Ex Post Price, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time Dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO real-time Imbalance Energy market for resources that cannot change output level within one Dispatch Interval and System Resources shall be the simple average of the relevant Dispatch Interval Ex Post Prices for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, or a Participating Load.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in Section 2.4 below.

2.3 Conditions for the Imposition of Mitigation Measures

2.3.1 In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 2.4 below.

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the ISO Real Time Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining real-time bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real time to produce an output level that is less than the ISO's Dispatch instruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a Market Clearing Price.

(3) Uneconomic production from an Electric Facility that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

2.4.2 Mitigation Measures may also be imposed to mitigate the market effects of a rule, standard, procedure, design feature, or known software imperfection of an ISO Market that allows a Market Participant to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure design feature, or software defect to preclude such manipulation of prices or impairment of efficiency.

2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

2.4.4 The ISO shall monitor ISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in an ISO Market or other payments. The ISO shall: (i) seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate.

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in Section 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

3.1.1 Conduct Thresholds for Identifying Economic Withholding

The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of the bid from a resource and shall be determined with respect to a reference level determined as specified in Section 3.1.1.1:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of a 200 percent increase or $100/MWh increase in the bid with respect to its Reference Level.

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

A reference level for each bid segment shall be calculated each day for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

1. Excluding non-positive proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily changes in fuel prices using gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Edison Company, or Pacific Gas and Electric Company), or, if the resource is not served from one of those three Service Areas, from the nearest of those three Service Areas. Accepted and justified bids above the applicable soft cap, as set forth in Section 39.2 of this Tariff, will be included in the calculation of reference prices.

2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

4. The mean of the Economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:

   i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or

   ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO Market Clearing Prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or $50 per MWh in the projected Hourly Ex Post Price at any location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

3.2.2 Price Impact Analysis

3.2.2.1 Bids to be Dispatched as Imbalance Energy.

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in projected Hourly Ex Post Prices as a result of simultaneously setting all such bids to their Reference Levels. If a change in the projected Hourly Ex Post Price exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.2.2 Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion. If the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff, the bid price shall be mitigated to the reference price and the Scheduling Coordinator for that

resource shall be paid the greater of the reference price or the relevant Dispatch Interval Ex Post Price. Bids mitigated in accordance with this Section 3.2.2.2 shall not set the Dispatch Interval Ex Post Price.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with FERC seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

(1) bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit, or

(2) bids that vary over time in a manner that appears unrelated to the change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

The conducts listed above are intended to be examples rather than a comprehensive list.

3.3 Consultation with a Market Participant

If a Market Participant anticipates submitting bids in an ISO Market administered by the ISO that will exceed the thresholds specified in Section 3.1 above for identifying conduct inconsistent with competition, the Market Participant may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Participant's bids. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the ISO, that the questioned conduct is consistent with competitive behavior, no further action will be taken. Upon request, the ISO shall also consult with a Market Participant with respect to the information and analysis used to determine reference levels under Section 3.1.1 above for that Market Participant.

4 MITIGATION MEASURES

4.1 Purpose

If conduct is detected that meets the criteria specified in Section 3, the appropriate mitigation measures described in this Section 4 shall be applied by the ISO. The conduct specified in Section 3.1.1 shall be remedied by the prospective application of a default bid measure as described in Section 4.2 for the specific hour that they violate the price and market impact thresholds.

4.2 Sanctions for Economic Withholding

4.2.1 Default Bid

A default bid shall be designed to cause a Market Participant to bid as if it faced workable competition during a period when: (i) the Market Participant does not face workable competition and (ii) has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

(a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for each component of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1 above.

(b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the real-time Imbalance Energy market during the pre-dispatch process prior to the real-time Imbalance Energy market based on the projected real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.

(c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.

(d) The ISO shall not use a default bid to determine revised MCPs for periods prior to the imposition of the default bid, except as may be specifically authorized by FERC.

(e) The Mitigation Measures shall not be applied to Energy Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below $91.87/MWh. If the Zonal Dispatch Interval Ex Post Price is projected to be above $91.87/MWh in any ISO Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.

(f) The Mitigation Measures shall not be applied to bids below $25/MWh.

(g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.

(h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO determines to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 9.3.10.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

4.4 Duration of Mitigation Measures

Bids will be mitigated only in the specific hour that they violate the price and market impact thresholds.

5 FERC-ORDERED MEASURES

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

6 DISPUTE RESOLUTION

If a Market Participant has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may seek a determination in accordance with the dispute resolution provisions of the ISO Tariff. In no event, however, shall the ISO be liable to a Market Participant or any other person or entity for money damages or any other remedy or relief except and to the extent specified in the ISO Tariff.

7 EFFECTIVE DATE

These Mitigation Measures shall be effective as of the date they are approved by the FERC.

ISO TARIFF APPENDIX Q

Eligible Intermittent Resources Protocol

APPENDIX Q

Eligible Intermittent Resources Protocol

EIRP 1.3 Scope

EIRP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to:

(a) Scheduling Coordinators (SCs);

(b) Eligible Intermittent Resources; and

(c) Participating Intermittent Resources.

EIRP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

EIRP 2 PARTICIPATING INTERMITTENT RESOURCE CERTIFICATION

EIRP 2.1 No Mandatory Participation

Eligible Intermittent Resources may elect to be scheduled and settled as the ISO Tariff provides for Generating Units, and are not required to seek certification as Participating Intermittent Resources.

EIRP 2.2 Minimum Certification Requirements

Those Eligible Intermittent Resources that intend to become Participating Intermittent Resources must meet the following requirements.

EIRP 2.2.1 Agreements

The following agreements must be executed:

(a) A Participating Generator Agreement that, among other things, binds the Participating Intermittent Resource to comply with the ISO Tariff;

(b) A Meter Service Agreement for ISO Metered Entities; and

(c) A letter of intent to become a Participating Intermittent Resource, which when executed and delivered to the ISO shall initiate the process of certifying the Participating Intermittent Resource. The form of the letter of intent shall be specified by the ISO and published on the ISO Home Page.

EIRP 2.2.2 Composition

The ISO shall develop criteria to determine whether one or more Eligible Intermittent Resources may be included within a Participating Intermittent Resource. Such criteria shall include:

(a) A Participating Intermittent Resource must be at least 1 MW rated capacity.

(b) A Participating Intermittent Resource may include one or more Eligible Intermittent Resources that have similar response to weather conditions or other variables relevant to forecasting Energy, as determined by the ISO.

(c) Each Participating Intermittent Resource shall be electrically connected at a single point on the ISO Controlled Grid, except as otherwise permitted by the ISO on a case-by-case basis as may be allowed under the ISO Tariff.

(d) The same Scheduling Coordinator must schedule all Eligible Intermittent Resources aggregated into a single Participating Intermittent Resource.

EIRP 2.2.3 Equipment Installation

A Participating Intermittent Resource must install and maintain the communication equipment required pursuant to EIRP 3, and the equipment supporting forecast data required pursuant to EIRP 6.

EIRP 2.2.4 Forecast Model Validation

The ISO must determine that sufficient historic and real-time telemetered data are available to support an accurate and unbiased forecast of Energy generation by the Participating Intermittent Resource, according to the forecasting process validation criteria described in EIRP 4.

EIRP 2.2.5 Information Requirements For Participating Intermittent Resource Export Fee

In order for the ISO to administer, implement and calculate the Participating Intermittent Resource Export Fee, each Participating Intermittent Resource jointly with, and through, its Scheduling Coordinator must provide the ISO with the following information and documents under the schedule and conditions set forth in this section. The ISO will maintain the confidentiality of all information and documents received under this section in accordance with ISO Tariff section 20 et seq.

(a) A certification, in the form posted on the ISO Homepage, signed by an officer of the Participating Intermittent Resource and its Scheduling Coordinator, identifying (1) the Export Percentage under EIRP 5.3.2, if any, and basis thereof, and (2) each contract to sell Energy or capacity from the Participating Intermittent Resource, including for each such contract, the counterparty, start and end dates, delivery point(s), quantity in MW, other temporal terms, i.e., seasonal or hourly limitations.

The certification must be updated by resubmission to the ISO (1) upon a request to modify the composition of the Participating Intermittent Resource under EIRP 2.4.2; or (2) within ten (10) calendar days of final execution of a new contract or any change in counterparty, start and end dates, delivery point(s), quantity in MW, or other temporal terms, as described above, for any prior certified contract. All other contractual changes will not trigger the obligation for recertification;

(b) Copies of all contracts, including changes, identified in the above-referenced certification; however, price information may be redacted from the contracts provided.

Each Participating Intermittent Resource, as of November 1, 2006, must initially provide the information requested by EIRP 2.2.5 in accordance with a market notice provided by the ISO to Participating Intermittent Resources. All other Eligible Intermittent Resources must satisfy EIRP 2.2.5 in order to become a Participating Intermittent Resource after November 1, 2006.

EIRP 2.3 Notice of Certification

When all requirements described in EIRP 2.2 have been fulfilled, the ISO shall notify the Scheduling Coordinator and the representatives of the Eligible Intermittent Resources comprising the Participating Intermittent Resource that the Participating Intermittent Resource has been certified, and is eligible for the settlement terms provided under Section 11.2.4.5 of the ISO Tariff, as conditioned by the terms of this EIRP.

EIRP 2.4 Requirements After Certification

EIRP 2.4.1 Forecast Fee

Beginning on the date first certified, a Participating Intermittent Resource must pay the Forecast Fee for all metered Energy generated by the Participating Intermitted Resource over the duration of the commitment indicated in the letter of intent described in EIRP 2.2.1(c).

The amount of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the ISO as a direct result of participation by Participating Intermittent Resources in ISO Markets, divided by the projected annual Energy production by all Participating Intermittent Resources.

The initial rate for the Forecast Fee, and all subsequent rate changes as may be necessary from time to time to recover costs incurred by the ISO for the forecasting conducted on the behalf of Participating Intermittent Resources, shall be posted on the

ISO Home Page. In no event shall the level of the Forecast Fee exceed the amount specified in ISO Tariff Appendix F, Schedule 4.

EIRP 2.4.2 Modification of Participating Intermittent Resource Composition

A Participating Intermittent Resource may seek to modify the composition of the Participating Intermittent Resource (e.g., by adding or eliminating an Eligible Intermittent Resource from the Participating Intermittent Resource). Such changes shall not be implemented without prior compliance with the written approval by the ISO. The ISO will apply consistent criteria and expeditiously review any proposed changes in the composition of a Participating Intermittent Resource.

EIRP 2.4.3 Changes in Scheduling Coordinator

This EIRP does not impose any additional requirement for ISO approval to change the Scheduling Coordinator for an approved Participating Intermittent Resource than would otherwise apply under the ISO Tariff to changes in the Scheduling Coordinator representing a Generating Unit.

EIRP 2.4.4 Continuing Obligation

A Participating Intermittent Resource must meet all obligations established for Participating Intermittent Resources under the ISO Tariff and this EIRP, and must fully cooperate in providing all data, other information, and authorizations the ISO reasonably requests to fulfill its obligation to validate forecast models, explain deviations, and implement the Participating Intermittent Resource Export Fees.

EIRP 2.4.5 Failure to Perform

If the ISO determines that a material deficiency has arisen in the Participating Intermittent Resource's fulfillment of its obligations under the ISO Tariff and this EIRP, and such Participating Intermittent Resource fails to promptly correct such deficiencies when notified by the ISO, then the eligibility of the Participating Intermittent Resource for the settlement accommodations provided in Section 11.2.4.5 of the ISO Tariff shall be suspended until such time that the unavailable data is provided or other material deficiency is corrected to the ISO's reasonable satisfaction. Such suspension shall not relieve the Scheduling Coordinator for the deficient Participating Intermittent Resource from paying the Forecast Fee over the duration of the period covered by the letter of intent described in EIRP 2.2.1(c).

EIRP 3 COMMUNICATIONS

EIRP 3.1 Forecast Data

The ISO may require various data relevant to forecasting Energy from the Participating Intermittent Resource to be telemetered to the ISO, including appropriate operational data, meteorological data or other data reasonably necessary to forecast Energy.

EIRP 3.2 Standards

The standards for communications shall be the monitoring and communications requirements for Generating Units providing only Energy and Supplemental Energy; as such standards may be amended from time to time, and published on the ISO Home Page.

EIRP 3.3 Cost Responsibility

An applicant for certification as a Participating Intermittent Resource is responsible for expenses associated with engineering, installation, operation and maintenance of required communication equipment.

EIRP 4 FORECASTING

The ISO is responsible for overseeing the development of tools or services to forecast Energy for Participating Intermittent Resources. The ISO will use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. Objective criteria and thresholds for unbiased, accurate forecasts shall be published on the ISO Home Page, and shall be used to certify Participating Intermittent Resources in accordance with EIRP 2.2.4.

EIRP 4.1 Hour-Ahead Forecast

The ISO shall develop expert, independent hourly forecasts of Energy generation on each Participating Intermittent Resource. A forecast shall be published each hour on the half hour for each of the next seven operating hours. Other forecasts, including a day-ahead forecast, may be developed at the ISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the Hour-Ahead Forecast that is available 30 minutes prior to the deadline for submitting the Preferred Hour-Ahead Schedule. The ISO shall use best efforts to provide reliable and timely forecasts. However, if the ISO fails to deliver the Hour-Ahead Forecast to the Scheduling Coordinator prior to 15 minutes before the deadline for submitting Preferred Hour-Ahead Schedules, then the Hour-Ahead Forecast shall be the most recent Energy forecast provided by the ISO to the Scheduling Coordinator for the operating hour for which Preferred Schedules are next due.

EIRP 4.2 Forecast Calibration

The ISO shall calibrate the forecast to eliminate bias as measured by net MWh deviations across any and all relevant time periods to minimize the expected cumulative net charges or payments that are recovered or allocated through Section 11.2.4.5 of the ISO Tariff.

EIRP 4.3 Confidentiality

The ISO shall maintain the confidentiality of proprietary data for each Participating Intermittent Resource in accordance with Section 20 of the ISO Tariff.

EIRP 5 SCHEDULING AND SETTLEMENT

EIRP 5.1 Schedules

Scheduling Coordinators shall be required to submit Preferred Hour-Ahead Energy Schedules (MWh) for the Generating Units that comprise each Participating Intermittent Resource that are identical, in the aggregate, to the Hour-Ahead Forecast published for that Participating Intermittent Resource (MWh).

EIRP 5.2 Settlement

After a Participating Intermittent Resource is certified, settlement shall be determined for each Settlement Period based on consistency of Schedules and bids submitted on behalf of such Participating Intermittent Resources with the rules specified in the ISO Tariff and this Protocol.

No Supplemental Energy bids or Adjustment Bids may be submitted on behalf of a Participating Intermittent Resource. Submitting such bids shall render the Participating Intermittent Resource ineligible for settlement according to Section 11.2.4.5 of the ISO Tariff for that Settlement Period. Such activity will be monitored in accordance with EIRP 7.

EIRP 5.3 Participating Intermittent Resource Export Fee

EIRP 5.3.1 Exemptions

After November 1, 2006, Participating Intermittent Resources shall be subject to the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F, for Energy generated, except to the extent the Participating Intermittent Resource is exempt under one or more of the following conditions:

(a) The owner of a Participating Intermittent Resource, as of November 1, 2006, utilizes the Energy generated from the Participating Intermittent Resource to meet its own Native Load outside the ISO Control Area. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will not apply to the added capacity unless exempt under another subsection of EIRP 5.3.1.

If the Participating Intermittent Resource subject to this exemption changes ownership, the Participating Intermittent Resource Export Fee will apply, except where the prior exempt owner demonstrates that the entire output of the Participating Intermittent Resource continues to be delivered to the exempt owner under a power purchase agreement for the purpose of serving the prior exempt owner's Native Load. The exemption will then continue only for the period of the power purchase agreement as provided in accordance with EIRP 2.2.5 and cannot exceed the MW quantity originally exempted.

(b) A Participating Intermittent Resource demonstrates in its certification under EIRP 2.2.5(a) an export contract with a starting term prior to November 1, 2006. An export contract is any power purchase agreement to sell Energy to any entity other than a load serving entity with an obligation under law or franchise to serve Demand within the ISO Control Area.

The exemption will apply to any extension of the current export contract through an evergreen or other existing extension provision. The exemption terminates upon termination of the export contract. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will apply only to Energy generated up to the contract quantity, unless the Participating Intermittent Resource demonstrates a basis for exemption under subsection (c) for the expanded capacity.

(c) A Participating Intermittent Resource demonstrates in its certification under EIRP 2.2.5(a) a contract to sell Energy to a load serving entity with Native Load within the ISO Control Area. Energy Service Providers with contractual obligations with customers within the ISO Control Area would be deemed a load serving entity with an obligation to serve Native Load within the ISO Control Area.

The exemption will apply to any extension of the current contract through an evergreen or other existing extension provision. The exemption terminates upon termination of the contract. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will continue to apply only to Energy generated up to the contract quantity unless the Participating Intermittent Resource demonstrates a basis for exemption under this subsection (c) for the expanded capacity.

EIRP 5.3.2 Participating Intermittent Resource Export Percentage

Based on the information required in EIRP 2.2.5 and application of the exemptions to the Participating Intermittent Resource Export Fee in EIRP 5.3.2, the ISO will determine an "Export Percentage" for each Participating Intermittent Resource that will be calculated as the ratio of the Participating Intermittent Resource's Pmax in the ISO Master File minus the MW, subject to an exemption under EIRP 5.3.2 on a MW basis to the Participating Intermittent Resource's Pmax in the ISO Master File. For example, a Participating Intermittent Resource with a Pmax of 100 MW and a contract with an ISO Control Area load serving entity for 40 MW would have an export percentage of (100-40)/100 = 60%. A Participating Intermittent Resource with Export Percentage greater than zero (0) will be deemed an Exporting Participant Intermittent Resource. The ISO will notify the Participating Intermittent Resource and its Scheduling Coordinator of the facility's Export Percentage. Any dispute regarding the ISO's determination of Export Percentage shall be subject to the dispute resolution procedures under Section 13 of the ISO Tariff.

EIRP 5.3.3 Quarterly Application of Participating Intermittent Resource Export Fee

Each quarter the ISO will charge Exporting Participating Intermittent Resources the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F.

EIRP 5.3.4 Allocation of Credit for Participating Intermittent Resource Export Fees Received

Payments received by the ISO from application of the Participating Intermittent Export Fee in accordance with EIRP 5.3 shall be allocated as a credit on a quarterly basis to Scheduling Coordinators with Net Negative Uninstructed Deviations in proportion to the to the amount of Net Negative Uninstructed Deviations that each Scheduling Coordinator was assessed for Participating Intermittent Resources settlement charges for ISO Charge Type 721 during the prior quarter.

EIRP 5.3.5 Recording of Exemptions and Notice of Termination

The ISO will record any exemption period ending date, if applicable, for each Participating Intermittent Resource. At the conclusion of the exemption period, the ISO will notify the Scheduling Coordinator for the Participating Intermittent Resource that the facility is no longer exempt from the Participating Intermittent Resource Export Fee.

EIRP 5.3.6 Annual Confirmation

On December 31 of each calendar year, each Participating Intermittent Resource shall confirm in the form posted on the ISO Homepage, signed by an officer of the Participating Intermittent Resource, that the operations of the Participating Intermittent Resource are consistent with any certification(s) provided to the ISO under EIRP 2.2.5.

EIRP 5.3.7 Audit Rights

In addition to the rights set forth in ISO Tariff Section 4.6.9, the ISO shall have the right to contact any counterparty to a contract relied upon under EIRP 5.3.1 for purposes of determining compliance with this EIRP.

EIRP 6 DATA COLLECTION FACILITIES

The Participating Intermittent Resource must install and maintain equipment to collect, record and transmit data that the ISO reasonably determines is necessary to develop and support a forecast model that meets the requirements of EIRP 4.

EIRP 6.1 Wind Resources

A Participating Intermittent Resource powered by wind must install at least one meteorological tower at a project location that is representative of the microclimate within the project boundary.

The meteorological tower must rely on equipment typically used in the wind industry to continuously monitor weather conditions at a wind resource site. Data collected shall be consistent with requirements published on the ISO Home Page. Such data must be gathered and telemetered to the ISO in accordance with EIRP 3.

If objective standards developed by the ISO indicate that the meteorological data may not be sufficiently representative of conditions affecting Energy output or changes in Energy output by that Participating Intermittent Resource, then the ISO may require that additional meteorological equipment be temporarily installed at another location within the project boundary. The cost of such equipment, which may be temporarily installed by the Participating Intermittent Resource or the ISO, shall be the responsibility of the Participating Intermittent Resource.

If objective standards indicate that the data collected from such a temporary site contribute significantly to the development of an accurate and unbiased forecast, then the Participating Intermittent Resource shall be responsible for installing and arranging for the telemetry of data from an additional permanent meteorological tower at such site, and for the reasonable cost, if any, that the ISO may have incurred to install and remove the temporary equipment. Relocation of the original meteorological tower to the new site will be allowed if the ISO determines that a sufficiently accurate and unbiased forecast can be generated from a single relocated meteorological tower.

EIRP 6.2 Other Eligible Intermittent Resources

Eligible Intermittent Resources other than wind projects that wish to become Participating Intermittent Resources will be required to provide data of comparable relevance to estimating Energy generation. Standards will be developed as such projects are identified and will be posted on the ISO Home Page.

EIRP 7 PROGRAM MONITORING

The ISO shall monitor the operation of these rules, and will in particular seek to eliminate any gaming opportunities provided by the flexibility provided Participating Intermittent Resources to self-select participation on an hourly basis.

Participating Intermittent Resources are expected to schedule and otherwise perform in good faith, and not seek to act strategically in a manner that causes financial gain through systematic behavior, where such gain results solely from the settlement accommodations provided under ISO Tariff Section 11.2.4.5.

If requirements specified in this technical standard are not met, then Participating Intermittent Resource certification may be revoked pursuant to EIRP 2.4.5. Any patterns of strategic behavior by Participating Intermittent Resources will be tracked, and the statistical significance of such deviations will be used by the ISO to evaluate whether changes in the rules defined in this EIRP are appropriate.

The ISO will monitor the impact of rules for Participating Intermittent Resources on Imbalance Energy and Regulation costs to the ISO.

EIRP 8 AMENDMENTS

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 22.10 of the ISO Tariff.

ISO TARIFF APPENDIX R

UDP Aggregation Protocol (UDPAP)

ISO TARIFF APPENDIX R

UDP Aggregation Protocol (UDPAP)

UAP 1.3 Scope

There are two types of UDP Aggregation Classifications:

(1) Basic UDP Aggregations: composed of Generating Units connected at the same substation and stepping up to the same voltage level bus bar, or

(2) Custom UDP Aggregations: composed of Generating Units connected at different substations and/or different voltage levels, particularly where the Generating Units to be aggregated are separated by ISO Controlled Grid facilities. Examples of a proposed Custom UDP Aggregation include hydroelectric units operating on a common watershed (but having multiple different interconnection points), or geothermal units fed from a common geothermal steam supply.

UAP 2 SUBMITTAL OF A REQUEST FOR UDP AGGREGATION

Requests for UDP Aggregation are submitted to the ISO and must include the following documentation:

(1) A completed UDP Aggregation Request form, which is available for downloading on the ISO website;

(2) A simplified electrical one-line diagram, which illustrates each resource, the connection of the resources to each other and to the ISO Control Area Grid;

(3) For Custom UDP Aggregations, a detailed description that explains physical operating interrelationships between the units, or, if there are no interrelationships, how the units are compatible and why an aggregation of these units for the purpose of calculating Uninstructed Deviation Penalties is reasonable.

UAP 3 ISO REVIEW OF A UDP AGGREGATION REQUEST

Upon receipt of a completed request form and accompanying attachments, the ISO shall review the request according to the criteria outlined herein. For Basic UDP Aggregations, the ISO shall review and approve or reject it within one week of receipt. The ISO shall review and approve or reject a request for a Custom UDP Aggregation within thirty (30) days of receipt.

UAP 3.1 Criteria for Reviewing a Request

UAP 3.1.1 Scheduling Coordinator and Interconnection Point

Uninstructed Deviations may be aggregated for resources that are:

(1) Represented by the same Scheduling Coordinator and

(2) Connected to the same ISO Controlled Grid bus and voltage level.

The ISO will consider, on a case-by-case basis, requests to aggregate Uninstructed Deviations among resources represented by the same Scheduling Coordinator but not sharing a common ISO Controlled Grid bus and voltage level based on an ISO review of impact on the ISO Controlled Grid. In particular, the ISO will consider whether the request concerns resources related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; whether the Energy production from one resource necessarily causes Energy production from other resource(s); and whether the operational arrangement of resources determines the overall physical efficiency of the combined output of all of the resources.

UAP 3.1.2 Additional Criteria

Additional eligibility criteria for a UDP Aggregation are as follows:

(1) Only Generating Units shall be eligible for UDP Aggregation. As a general rule, pump-generating Units (or a Physical Scheduling Plant [PSP] containing a pump-generating Unit) cannot be part of a UDP Aggregation. However, it is possible that generating Units could form a UDP Aggregation comprised entirely of pump-generating Units whose operation is uniform, that is, Units all operating in either Generation mode or all in pump mode, but never mixed.

(2) UDP Aggregations cannot include any of the following:

(a) Load;

(b) Condition 2 Reliability Must Run (RMR) Units;

(c) Participating Intermittent Resources;

(d) Generating Units less than 5 MW; or

(e) Generating Units that span active or inactive Congestion Zones.

(3) The resources must have ISO direct telemetry and must be fully compliant with the ISO's direct telemetry standards.

(4) The Generating Units must have the same relative effect on all network elements for which the Generating Units have at least a five (5) percent effectiveness factor, that is, for those network elements for which a 1 MW change in the output of the Generating Unit changes the flow across that element by at least 0.05 MW. For the purposes of this item (4), the "same relative effect" means that the effectiveness factors of any Generating Unit relative to a network element cannot differ by more than 10% from the midpoint effectiveness factor of all the units. The midpoint effectiveness is the arithmetic mean of the two most different effectiveness factors to be aggregated.

(5) Custom UDP Aggregations involving units not directly connecting to the ISO Controlled Grid must recognize the transfer limits and status of the intermediate local facilities.

(6) The applicable Pmax of aggregated groups of resources will exclude units that are not operating.

UAP 3.1.3 Approval of a Request

If a UDP Aggregation request is approved, the ISO shall create a new unique Resource ID, which reflects the identity or location of the units and stipulates the UDP Aggregation, but which cannot be used for scheduling purposes. The ISO shall inform the Scheduling Coordinator of the approval and ask the Scheduling Coordinator to confirm the desired start date of the UDP Aggregation. When that confirmation has been received, the new aggregation will be entered into the ISO systems. Unless otherwise agreed to by the Scheduling Coordinator and the ISO, the UDP Aggregation will become effective on the first day of the month following approval. The Units in an approved UDP Aggregation are obligated to follow their individual schedules and instructions at all times.

UAP 3.1.4 Rejection of a Request

If the ISO determines that the proposed UDP Aggregation is likely to impact grid reliability or the reliability of transmission systems or equipment of intermediate entities between the relevant resources and the ISO grid, the request will be rejected. If the ISO rejects a request, the ISO shall inform the Scheduling Coordinator, and forward to it the reason for the rejection. The ISO may suggest alternative solutions if it has adequate time and data. The Scheduling Coordinator may choose to resubmit based on the ISO's recommendations, or to close the request.

UAP 4 MODIFICATIONS TO AN EXISTING UDP AGGREGATION

UAP.4.1 Status of UDP Aggregation

An approved UDP Aggregation shall be considered active until otherwise requested by the Scheduling Coordinator.

UAP 4.2 Suspension by the ISO

The ISO may temporarily suspend any aggregation as needed to ensure reliability. The ISO may also suspend previously approved UDP Aggregations if, due to changes to the grid, to the aggregated Generating Units, or to the facilities connecting aggregated Generating Units to the grid, the UDP Aggregation no longer meets the criteria set forth in Sections 3.1.1 and 3.1.2 of this ISO Protocol.

If the ISO must suspend the UDP Aggregation due to a forced outage or other unanticipated event, the ISO shall provide notice that the UDP Aggregation has been suspended as soon as practical after the affecting event, but in no case longer than 72 hours after that event. If the ISO must suspend the UDP Aggregation due to future changes, the ISO shall notify the affected Scheduling Coordinator (1) that the UDP Aggregation will be suspended and (2) when the UDP Aggregation will be suspended as soon as practical after the ISO determines the UDP Aggregation must be suspended.

The ISO shall write a report that explains the reason for the suspension and that specifies the effective date and time. The ISO will forward the report to the Scheduling Coordinator and take steps to have the aggregation removed from the ISO systems.

In the event that a resource in a UDP Aggregation changes from one Scheduling Coordinator to another, the UDP Aggregation will be suspended. In order to reinstate the aggregation, the new Scheduling Coordinator must submit a new request reflecting the change.

UAP 4.3 Request for Modification by a Scheduling Coordinator

A Scheduling Coordinator may request a modification to an existing aggregation up to once per calendar month. A request for modification will follow the same procedures as a new request.

ISO TARIFF APPENDIX S

Station Power Protocol

STATION POWER PROTOCOL

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STATION POWER PROTOCOL (SPP)

SPP 1 General Conditions

SPP 1.1 Procurement

Station Power may be voluntarily self-supplied through On-Site Self Supply or Remote Self Supply. Third Party Supply may serve Station Power only to the extent permissible under the rules and regulations of the applicable Local Regulatory Authority.

SPP 1.2 Eligibility

SPP 1.2.1 Only Station Power loads associated with Generating Units in the ISO Control Area that are part of an approved Station Power Portfolio may be self-supplied in accordance with this SPP. Each Generating Unit must be subject to a PGA, QF PGA, or MSS Agreement. Any generating facility outside the ISO Control Area owned by the same entity is eligible to provide Remote Self-Supply to Station Power loads, subject to the terms of this SPP. Generating Units wishing to self-supply Station Power, by means other than netting permitted under Section 10.1.3 of this ISO Tariff, shall complete the application process specified in SPP 2.

SPP 1.2.2 Station Power may be self-supplied by a single corporate entity, government agency, or joint powers agency or other legal entity organized under the laws of the State of California. A Station Power Portfolio may not include any facilities that are owned by the owner's corporate Affiliates. In the case of a joint powers agency, a Station Power Portfolio may not include facilities independently owned by one or more members or other legally distinct entities. If an entity owns a portion of a jointly owned Generating Unit, such ownership share may be included in a Station Power Portfolio up to the amount of the associated entitlement to Energy from the jointly-owned Generating Unit provided that: (i) the entity has the right to call upon that Energy for its own use; and (ii) the Energy entitlement is not characterized as a sale from the jointly owned Generating Unit to any of its joint owners.

SPP 1.2.3 Net Output from generating facilities outside the ISO Control Area may be included in a Station Power Portfolio and used as a source of Remote Self-Supply to serve Station Power of Generating Units in the ISO Control Area and part of the Station Power Portfolio, so long as the following conditions are fulfilled:

(a) Imports of Net Output must be scheduled using an interchange ID specified by the ISO;

(b) Import Schedules using such interchange ID do not exceed the available Net Output of such generating facilities in any hour;

(c) Firm transmission service to a Scheduling Point that assures delivery into the ISO Control Area is secured; and

(d) Meter data for generating facilities located outside the ISO Control Area shall be subject to ISO audit to verify performance in accordance with these requirements.

SPP 1.3 Limitations

SPP 1.3.1 Station Power supplied by contemporaneous on-site Generation is treated as permitted netting under Section 10.1.3 of this ISO Tariff. This SPP neither expands opportunities for nor imposes additional conditions on permitted netting. In accordance with this ISO Tariff such contemporaneous self-supplied Station Power need not be scheduled with the ISO.

SPP 1.3.2 Self-supply of Station Power shall be strictly voluntary. Nothing in this SPP is intended to: 1) preclude a Generating Unit from purchasing Station Power pursuant to an applicable retail rate or tariff; or 2) supersede otherwise applicable jurisdiction of a Local Regulatory Authority, except in the event of a conflict between federal and state tariff provisions, in which case the federal tariff provisions will control.

SPP 2 Station Power Requirements and Review

SPP 2.1 Applications to Self-Supply Station Power

SPP 2.1.1 An application to establish a Station Power Portfolio or to modify the configuration of Station Power meters or the Generating facilities included in a Station Power portfolio must be submitted according to the process specified by the ISO and posted on the ISO Home Page, and shall include the following information:

(a) One-line diagrams clearly showing the location and ownership of all Generating Units and Station Power meters, their connection to the ISO Controlled Grid or distribution system, and the status of breakers and switchgear for normal system operation.

(b) Identification of any generating facilities outside the ISO Control Area, to be used to provide Remote Self Supply of Station Power within the proposed Station Power Portfolio. No loads associated with generating facilities outside the ISO Control Area may be supplied under this SPP.

(c) Certification that the applicant is the sole owner of all generating facilities proposed to be included in the Station Power Portfolio, and that the applicant has the right to call on Energy for its own use from its ownership share of any jointly owned facilities that are proposed to be used to self supply Station Power.

(d) Demonstration that each Station Power meter is certified in accordance with the ISO Tariff.

(e) Verification that each Station Power meter is subject to a Meter Service Agreement for ISO Metered Entities, and that each Generating Unit is bound to the ISO Tariff by a PGA, QF PGA, or MSS Agreement.

(f) Verification that the applicant has arranged for terms of service with the responsible UDC or MSS Operator for the use of any distribution facilities required to self-supply Station Power.

SPP 2.1.2 On the ISO's written request, the applicant will provide additional information that the ISO reasonably determines is necessary to verify the planned operation of the Station Power Portfolio and meet the requirements of SPP 2.1.1.

SPP 2.2 ISO Monitoring and Review

SPP 2.2.1 The ISO will take the following actions with respect to each application to establish a Station Power Portfolio:

(a) The ISO shall post on the ISO Home Page a listing of the specific Station Power meters and Generating Units located in the ISO Control Area, and any generating facilities outside the ISO Control Area, that compose each Station Power Portfolio, and which are eligible to participate in the self-supply of Station Power in accordance with this SPP.

(b) The ISO will provide the appropriate UDC or MSS Operator and the Local Regulatory Authority with one-line diagrams and other information regarding each application.

(c) The ISO will make a determination in consultation with the UDC or MSS Operator and the Local Regulatory Authority on the factual question of whether distribution facilities are involved in the requested self-supply of Station Power. Any disputes regarding such determinations shall be subject to the dispute resolution procedures of this ISO Tariff.

(d) The ISO will verify metering schemes and assign unique load identifiers consistent with the ISO Data Templates and Validation Rules that the Scheduling Coordinator responsible for each meter will be required to use for scheduling and settlement.

SPP 2.2.2 The ISO shall promptly review each application to establish or modify a Station Power Portfolio. Within ten (10) Business Days after the submittal of the application, the ISO shall notify the applicant in writing that the application is complete, or shall list any specific deficiencies or additional information that the ISO reasonably requires to complete the application. The ISO shall use all reasonable efforts to make the changes necessary for the new or modified configurations to take effect and the Station Power Portfolio to begin self-supplying Station Power within twenty (20) Business Days after a complete application is submitted. In no event shall a Station Power Portfolio begin self-supplying Station Power until any and all required changes to the configuration of metering or other equipment are completed as required under SPP 6. The ISO will have an ongoing right to request additional information reasonably necessary to verify that conditions on the self-supply of Station Power as specified in this SPP are met.

SPP 3 Self-Supply Verification and ISO Charges

SPP 3.1 Self-Supply Verification

At the end of each Netting Period, the ISO will calculate the Net Output for each Generating Unit in the Station Power Portfolio. If the Net Output is positive, then all Station Power associated with that Generating Unit will have been served by On-Site Self Supply. Any positive Net Output from facilities in the Station Power Portfolio will be available to provide Remote Self Supply to any Generating Unit with negative Net Output. If the available Remote Self Supply is less than the aggregate negative Net Output in the Station Power Portfolio, then such shortfall will be deemed to have been served by Third Party Supply. The ISO will incorporate these determinations in its accounting and billing for the Netting Period by reassigning Station Power to unique load identifiers for Remote Self Supply and Third Party Supply, as required.

SPP 3.2 Charges on Metered Demand

Station Power that is not eligible for permitted netting in accordance with Section 10.1.3 of this ISO Tariff must be scheduled in accordance with the ISO Tariff, and will be assessed all charges applicable to metered Demand under the ISO Tariff, except as provided in SPP 4.1.

SPP 3.3 Administrative Charge

Scheduling Coordinators of Generating Units that have Station Power meters shall be assessed an administrative charge in accordance with Schedule 5 of Appendix F to the ISO Tariff.

SPP 4 Transmission Service

SPP 4.1 Station Power Load that is directly connected to the transmission facilities or directly connected to the Distribution System of a UDC or MSS Operator located in a PTO Service Territory and that is determined to have been served by On-Site Self Supply shall be deemed not to have used the ISO Controlled Grid and shall not be included in the Gross Load of the applicable UDC or MSS Operator. Station Power that is served by Wheeling service and that is determined to have been served by On-Site Self Supply shall be deemed not to have used the ISO Controlled Grid and shall not be included in the hourly schedules (in kWh) of the applicable Scheduling Coordinator that are subject to the Wheeling Access Charge.

SPP 4.2 Station Power Load that is directly connected to the transmission facilities or directly connected to the Distribution System of a UDC or MSS Operator located in a PTO Service Territory and that is determined to have been served by Remote Self-Supply or Third Party Supply shall be included in the Gross Load of the applicable UDC or MSS Operator. Station Power that is served by Wheeling service and that is determined to have been served by Remote Self-Supply or Third Party Supply shall be included in the hourly schedules (in kWh) of the applicable Scheduling Coordinator that are subject to the Wheeling Access Charge.

SPP 4.3 If the Generating Unit requires the use of distribution facilities or other facilities that are not part of the ISO Controlled Grid, then the Generating Unit will be subject to the appropriate charges of the applicable UDC, MSS Operator or owner of such non-ISO Controlled Grid Facilities.

SPP 5 ENERGY PRICING

All deviations between scheduled and metered Generation or Station Power will be settled at the applicable zonal price. The determination of Net Output and attribution of On-Site Self Supply, Remote Self Supply and Third Party Supply to serving Station Power under this SPP shall apply only to determine whether Station Power was self-supplied during the Netting Period and will have no effect on the price of Energy sold or consumed by any facility in the Station Power Portfolio.

SPP 6 METERING

SPP 6.1 In order to self-supply Station Power under this SPP by means other than netting permitted under Section 10.1.3 of this ISO Tariff, a Generating Unit must be subject to a Meter Service Agreement for ISO Metered Entities pursuant to ISO Tariff Section 10.3.1. A meter certified in accordance with the ISO Tariff is required for Station Power Load taken under the SPP. Separate metering is required for any on-site Load that does not meet the definition of Station Power. Under no circumstances may ineligible Loads be included in the meter data collected by the ISO from a Station Power meter.

SPP 6.2 Any costs associated with owning or operating metering or related facilities necessary to self-supply Station Power according to the terms of this SPP are the responsibility of the owner-applicant.

SPP 6.3 A single Scheduling Coordinator must represent the unique load identifiers assigned by the ISO for On-Site Self-Supply and Remote Self-Supply associated with each Station Power meter.

SPP 7 PROVISION OF DATA TO UDC OR MSS OPERATOR

The ISO will provide the applicable UDC or MSS Operator with the amount of On-Site Self Supply, Remote Self-Supply, and Third Party Supply serving Station Power at the granularity required to allow the UDC or MSS Operator to assess charges, if any, under the applicable retail tariff(s).

ISO TARIFF APPENDIX T

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