AESO Revenue Metering Technical Requirements—Rodan Comments

APPENDIX

Aug 20/19

Table of Contents

APPENDIX 1 – OWNERSHIP OF RESPONSIBILITIES

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	2.6 Metering Systems (a) 2.5 Data Systems (a)	Sections 1-10
Summary of Rules	• **AESO** responsible for management of **MPDR**s. • **MDM**s responsible for Meter Data Services. • **MSP**s responsible for Meter System Services.	• All responsibilities placed on the legal owner of a facility.

<u>Rodan Recommendations:</u>

1. Add a clause to Section 502.10 that the legal owner of a facility is free to contract Metering System Services to an **MSP**, and Meter Data Services to an **MDM**.

2. Add a clause to Section 502.10 that all entities providing **MSP** & **MDM** services to be recognized and approved by the **AESO**.

<u>Reasons:</u>

1. Legal owners seldom provide Metering System Services, or Meter Data Services themselves. Including a clause in Section 502.10 that they are free to contract these responsibilities will provide clarity for market participants and would be a more accurate representation of how the Alberta Electricity Market currently operates.

2. Providing Metering System Services and Meter Data Services is a highly nuanced field. In order to carry out this type of work and to comply with applicable standards and codes, providers need to be equipped with the proper systems, procedures, knowledge and experience. Ensuring that providers are qualified for this work would contribute to the overall performance, reliability and accuracy of Revenue Metering Systems and Settlements.

APPENDIX 2 – METER SERVICE PROVIDER & METERING SYSTEM SERVICES: ROLES, PROCEDURES AND RESPONSIBILITIES

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	2.6 Metering Systems (b) 6.2 Service Scope 6.3 System Requirements 6.4.1 General 6.4.2 Security & Access 6.4.3 Testing 6.4.4 Restoration 6.4.5 Alternative Metering Data Sources **APPENDIX 11** DEFINITIONS	Restoration - Section 10(1)-(5)
Summary of Rules	• Meter Service Provider (**MSP**) & Metering System Services (**MSS**) are defined. • **MSP** roles and responsibilities are outlined. • **MSS** procedures and requirements are outlined. • Existing Measurement Standard differentiates between *Metering System Provider* and *Metering Service Provider*.	• Restoration requirements and procedures are outlined, but all responsibility is placed on the legal owner of a facility.

Rodan Recommendations:

1. Include definition of **MSP** in Section 502.10
2. Include definition of **MSS** in Section 502.10
3. Clarify the roles and responsibilities of an **MSP** in Section 502.10
4. Clarify the procedures and requirements for providing **MSS** in Section 502.10
5. Eliminate *Metering System Provider* and *Metering Service Provider* definitions. Replace with Meter Service Provider (**MSP**).

Reasons:

1. **MSP**s form a large and critical component of the Alberta Electricity Market. They are responsible for the proper engineering, installation and maintenance of revenue metering systems which are used for settlement purposes on a legal owner's behalf. AUC Rule 021 contains references to Meter Service Provider (**MSP**), but the roles and responsibilities of an **MSP** is not defined nor elaborated anywhere within that document.
2. Providing **MSS** is vital to the proper and accurate operation of revenue metering systems and should be defined in Section 502.10.

3. Proposed Section 502.10 does not address the roles and responsibilities of an **MSP** which may result in market participants seeking this information from other regulatory bodies such as the AUC and Measurement Canada. However, neither the AUC or Measurement Canada have language in their policies and manuals that clearly outline **MSP** roles and responsibilities. For this reason, it is important to include this information in proposed Section 502.10. Clarifying **MSP** roles and responsibilities will promote system-wide consistency and provide legal owners with assurance that all providers are following the same set of rules.

4. Including the procedures and requirements for **MSS** in Section 502.10 will promote system-wide consistency and provide legal owners with assurance that providers are performing services to a provincial standard. In the absence of clearly defined procedures, **MSP** may implement **MSS** procedures which may not comply with AESO expectations and standards.

5. There is some overlap between the definitions of *Metering <u>System</u> Provider* and *Metering <u>Service</u> Provider* in the existing Measurement Standard. We suggest replacing both with Meter Service Provider (**MSP**), which is the same terminology used in AUC Rule 021.

APPENDIX 3 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: METER REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	6.3.3 Meter	Meter - Section 7(a)-(c)
Summary of Rules	• Approval under Section 9(1), Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act subject to the terms and conditions of any applicable dispensations(s) listed as requirement. • Labelling requirements for revenue meters are outlined (Ex. Multipliers, **CT**/**PT** Ratios, Loss Compensation Status). • Register requirements are outlined. • Communication port requirements are outlined. • Security requirements to prevent unauthorized access and tampering are outlined. • Accuracy requirements are outlined. • Recorder minimum memory for storage of interval data outlined (14 days). • Recorder retention of readings and, if applicable, all clock functions in absence of line power defined (14 days) listed as requirement.	• Measurement Canada approval, verification, re-verification and sealing in accordance with the Electricity and Gas Inspections Act of Canada subject to the terms and conditions of any applicable dispensation agreement listed as requirement. • Accuracy class rating for Watthour and Varhour measurement that equals or exceeds the values specified in Table 1 if they are non-dispensated listed as requirement.

<u>Rodan Recommendations:</u>

1. Specify in Section 502.10 the required registers and metrics to be recorded. This should include, at minimum, separate registers for cumulative active energy and reactive energy transferred in the required directions at a metering point.

2. Include in Section 502.10 the minimum memory requirement for storage of interval data. We recommend 14-35 days.

3. Include in Section 502.10 the minimum requirement for retention of meter readings and, if applicable, all clock functions in the absence of line power. We recommend 14-35 days.

<u>Reasons:</u>

1. Measurement Canada policy S-E-02 permits the use of a net register for bi-directional meters with only one register, and AUC Rule 021 does not outline revenue meter register requirements. For these reasons, Section 502.10 should outline the register requirements that comply with the **AESO**'s expectations.

2. AUC Rule 021 does not include any guidelines for minimum memory requirements for the storage of interval data in a revenue meter. Revenue meters should have sufficient memory to store interval data for specified duration of time in the event of a communication system failure.

3. A minimum retention period of meter readings and, clock functions in the absence of line power is necessary to prevent data loss and maintain clock synchronization if a revenue meter loses power for an extended period of time.

APPENDIX 4 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: BACKUP METERING REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	Not Defined.	Not Defined.
Summary of Rules	N/A	N/A

<u>Rodan Recommendations:</u>

1. Introduce sealed backup (alternate) revenue meter requirement for new meter points. The backup (alternate) meter can share Instrument Transformers with the primary meter but should have a dedicated test switch.

<u>Reasons:</u>

1. When a meter point has a sealed backup (alternate) meter available, it eliminates the need to seek temporary dispensation from Measurement Canada in the event of a primary meter failure. Backup (alternate) meters also reduce site downtime and eliminate the need for data estimations. In many cases, proxy data used for data estimations comes from measurement systems that are not revenue grade, and typically have a lower accuracy rating. Backup (alternate) meters also serve as an excellent alternate/secondary source for meter testing.

   The capital cost for an additional revenue meter is, in most cases, lower than the cost attributed to replacing a failed meter, which include but are not limited to:
   - Labour costs to seek Measurement Canada dispensation and complete necessary paperwork and contracts between affected parties.
   - Revenue loss as a result of potential site downtime.
   - Expedited repair and field labour costs.
   - Potential revenue loss as a result of data estimations.

APPENDIX 5 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: SEALING AND SECURITY REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	6.3.3 Meter (e) 6.3.4 Recorder (f)	Meter - Section 7 (a)
Summary of Rules	• Security requirements to prevent unauthorized access and tampering of revenue meters, recorders, meter cabinets, test switches, meter demand reset mechanisms and communications equipment are outlined.	• Measurement Canada sealing in accordance with the Electricity and Gas Inspections Act of Canada subject to the terms and conditions of any applicable dispensation agreement listed as requirement for the revenue meter. **Note:** Proposed Section 502.10 does not include any security requirements except for the revenue meter.

Rodan Recommendations:

1. Include in Section 502.10 the minimum security requirements to prevent unauthorized access and tampering of revenue metering systems including revenue meters, recorders, meter cabinets, test switches, instrument transformer cabinets, instrument transformer secondary terminals, CT shorting terminals, communications equipment, demand reset mechanisms, meter socket ring seals and meter power/potential reference fuse blocks and/or breakers.

Reasons:

1. Measurement Canada regulations to prevent unauthorized access and tampering are defined somewhat in policy S-EG-02. Section 502.10 should list the minimum requirements that the AESO expects in order to prevent and reduce unauthorized access and tampering of revenue metering systems.

   If the meter is the only component of a revenue metering system that is required to have a seal, it leaves vulnerabilities and enables tampering methods such as:
   - Shorting CTs via test switch or shorting terminals
   - Changing taps on CTs & PTs at secondary terminals or terminal blocks
   - Turning off meter power, or potential references via test switches, fuse blocks, and/or breakers
   - Removing meters from sockets
   - Tampering via re-programming of communications equipment

APPENDIX 6 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: COMMUNICATION REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	6.3.5 Remote Communications Equipment	Not Defined.
Summary of Rules	• Minimum remote communications equipment requirements including reliability, security against unauthorized access, requirements for protocol schemes suitable for the communication path that prevent corruption of interval data during transmission are outlined.	N/A

Rodan Recommendations:

1. Include rules for minimum remote communications equipment requirements that include reliability, security and suitable protocol scheme requirements.

2. Consider prohibiting or restricting the use of analog phone lines for interval data transmission on new meter points unless there is no other viable option.

Reasons:

1. To ensure reliable data transmission. To prevent corruption of data and unauthorised access to remote communications equipment and legal owner's data.

2. Analog phone lines are less reliable and secure when compared to modern communication methods such as ethernet and cellular TCP/IP. Analog phone lines are also prone to transients which can irreversibly damage a meter's communication port and often requires exchanging the meter if the port cannot be repaired or replaced without breaking the Measurement Canada seal.

APPENDIX 7 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: CURRENT TRANSFORMER (CT) TOTALIZATION

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	Not Defined.	Not Defined.
Summary of Rules	N/A	N/A

<u>Rodan Recommendations:</u>

1. Outline the rules for **CT** series connections. Indicate whether a totalizing current transformer is required, or if **CT** secondaries can be connected in series without the use of a totalizing current transformer.

2. Outline the maximum number of **CT**s that can be totalized, series-connected or paralleled. We recommend a maximum of two **CT**s for each current input on a revenue meter.

<u>Reasons:</u>

1. <u>Measurement Canada policy S-E-08 excerpt:</u>
   9.1.1 Additive totalizing of two or more circuits may be performed in the following manners:
      a) *via paralleling of current transformer (**CT**) secondaries, or*
      b) *through use of a totalizing current transformer.*
   *9.1.2 Paralleling **CT** secondaries is permitted subject to the following conditions:*
      a. *paralleled circuits are of the same voltage and frequency;*
      b. *current transformers have identical ratios;*
      c. *the voltage circuits of the meter are supplied from a common bus to which the primary circuits are connected; and,*
      d. *the meter ratings are sufficient for the totalized load.*
   9.1.3 A totalizing current transformer may be used subject to the following conditions:
      a. *the primary circuits are of the same voltage and frequency;*
      b. *the voltage circuits of the meter are supplied from a common bus to which the primary circuits are connected;*
      c. *the primary windings of the totalizing transformers are supplied from corresponding phases of the primary lines;*
      d. *each primary winding of the totalizing transformer in conjunction with its primary current transformer produces the correct proportion of the total secondary current; and,*
      e. *the overall multiplier for the totalizing transformer is the sum of the ratios of all the primary current transformers which supply the totalizing transformer.*

   There are installations in Alberta that utilize **CT** series connections without the use of a totalizing current transformer. This indicates that some market participants are not aware of or have a misunderstanding of Measurement Canada policy S-E-08. It would be beneficial to clarify this in Section 502.10.

2. Each additional **CT** that is totalized, series-connected or paralleled increases the overall burden and possible error of a revenue metering system. Measurement Canada policy S-E-08 does not define a limit for the maximum allowable number of totalized, series-connected or paralleled **CT**s in a circuit. Having a limit included in Section 502.10 will reduce the overall error of revenue metering systems and will prevent legal owners from totalizing, series-connecting or paralleling an unreasonable number of **CT**s. Troubleshooting and testing becomes more difficult as more **CT**s are totalized, series-connected or paralleled.

APPENDIX 8 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: LOSS COMPENSATION REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	6.3.2 Measurement Transformers (d)	Measurement Transformer Facility - Section 6 (b)
Summary of Rules	• Requirement that applicable winding(s) of the current and potential instrument transformers must be located and connected in a manner that, wherever practically possible, avoids compensation methods and produces a real metering point.	• Requirement that the legal owner of a revenue metering system must ensure that any current or potential instrument transformer for a revenue metering system is located and connected without compensation methods and produces a real metering point, unless the **ISO** otherwise approves.

Rodan Recommendations:

1. Outline the minimum line lengths (on supply-side and load-side if a power transformer is located between the **RMP** and **VMP**) before line loss compensation is required.

2. Define reference/test temperature for determining transformer load loss and percent impedance values.

3. Include reference to Measurement Canada Policy E-36 for applications where site specific loss adjustments are required.

Reasons:

1. This is often a point of discussion but is not clearly defined in any standard.

2. Depending on the standard that a power transformer is tested against, there can be variance in the test temperature used to determine transformer load loss and percent impedance values. The most common are 75 and 85 Degrees Celsius. Measurement Canada uses 75 Degrees Celsius but its not clearly defined and the rule is spread out across three documents (Measurement Canada E-36, IESO MDP_STD_0005 and IESO MDP_PRO_0011[1]). Because reference/test temperature has a significant impact on the compensation values (Example: Lower temperature results in lower loss values), **AESO**s preference should be clearly defined in Section 502.10.

3. Based on our experience, many Alberta Electricity Market participants are unaware of this policy and the requirements for performing site specific loss adjustments. Including a reference in Section 502.10 will provide clarity and ensure all Alberta market participants are compensating to Measurement Canada standards.

[1] Measurement Canada refers to IESO standards for determining loss compensation using VA Method.

APPENDIX 9 – METERING SYSTEM DESIGN, ENGINEERING AND INSTALLATION REQUIREMENTS: GENERALLY ACCEPTED UTILITY METERING PRACTICES

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 3** GENERALLY ACCEPTED UTILITY METERING PRACTICES	Not Defined.
Summary of Rules	• Sealed revenue approved meter(s)/recorder(s) are used on all installations • Revenue approved instrument transformers or cores are used on all installations • Either 2 element or 3 element metering configurations are used depending upon the electrical arrangement being metered (no 2 ½ element configurations are used) • A test switch is provided that enables the isolation of potentials and the shorting of all currents to the meter • Wiring from instrument transformers is either colour coded or clearly and unambiguously labeled at all interfaces • All meter enclosures are lockable and kept locked. • Test switch covers are sealed. • Metering and instrument transformer cabinets are sealed. • Meter demand reset mechanisms are sealed. • Wherever possible, the meter/recorder always remain powered. • Recorders have an interval data storage capacity of no less than 14 days. • Meters/recorders have a backup battery (or other) system that will maintain data and clock integrity for no less than 14 days in the absence of line power. • Instrument transformers are not overburdened by the meter and any other devices/wiring that may be included as part of the instrument transformer/meter circuit. • Meters that are loss compensated are labeled as such. • Meters that have unity **PT** and or **CT** ratios have the appropriate multiplier labeled. • Local meter clock displays should be in prevailing clock time. • Metering enclosures that contain voltages in excess of 120V are clearly labeled as containing 'High Voltage' (277/480, 347/600). • Metering system wiring diagrams should either be included within the metering enclosure or available upon request. • The metering system must have a single ground point.	N/A

Rodan Recommendations:

1. Include in Section 502.10 a list of generally accepted utility metering practises similar to the list in the existing **AESO** Measurement Standard.

Reasons:

1. Generally accepted utility metering practises are spread out across a vast number of Measurement Canada policies. It would be beneficial to summarize the key practices in Section 502.10. A summarized list can be used as a quick spot-check by **MSP**s and legal owners to improve efficiencies and ensure that no major oversights are being made during the design phase of new meter system projects, without having to comb thru numerous Measurement Canada policy documents.

APPENDIX 10 – METER & INSTRUMENT TRANSFORMER ACCURACY; METERING SYSTEM ACCURACY

<table>
<tr><th colspan="3">Existing vs. Proposed Standard</th></tr>
<tr><th>Description</th><th>AESO Measurement Standard (Existing)</th><th>Section 502.10 (Proposed)</th></tr>
<tr>
<td>Applicable Sections</td>
<td>APPENDIX 1 SCHEDULE OF ACCURACIES FOR METERING EQUIPMENT APPROVED UNDER SECTION 9(1) OF THE ELECTRICITY AND GAS INSPECTION ACT
APPENDIX 2 SCHEDULE OF ACCURACIES FOR METERS APPROVED UNDER SECTION 9(3) OF THE ELECTRICITY AND GAS INSPECTION ACT
APPENDIX 5 METERING SYSTEM IN-SITU TESTING – Section 5: METERING SYSTEM IN-SITU TEST RECORD</td>
<td>Meter - Section 7(b)
Refers to Instrument Transformer Facility - Section 6 - Table 1
Meter Testing - Section 9(c)</td>
</tr>
<tr>
<td>Summary of Rules</td>
<td>
(NON-DISPENSATED METERING EQUIPMENT)
<table>
<tr><th>Metering Point Capacity (MVA)</th><th>Watthour Meter Accuracy Class</th><th>Varhour Meter Accuracy Class</th><th>Measurement Transformers Accuracy Class</th></tr>
<tr><td>1.0 and Above</td><td>0.2 %</td><td>0.5 %</td><td>0.3 %</td></tr>
<tr><td>Below 1.0</td><td>0.5 %</td><td>1.0 %</td><td>0.3 %</td></tr>
</table>
(DISPENSATED METERING EQUIPMENT)
<table>
<tr><th></th><th colspan="2">Meter Accuracy</th></tr>
<tr><th>Metering Point Capacity (MVA)</th><th>Points of Delivery</th><th>Points of Supply</th></tr>
<tr><td>10 and Above</td><td>1.0 %</td><td>1.0 %</td></tr>
<tr><td>Below 10</td><td>1.0 %</td><td>1.0 %</td></tr>
</table>
Allowable testing measurement error of +/- 3%.
</td>
<td>
Table 1
<table>
<tr><th>Metering Point Capacity (MVA)</th><th>Watthour Meter Accuracy Class</th><th>Varhour Meter Accuracy Class</th><th>Measurement Transformer Accuracy Class</th></tr>
<tr><td>1.0 and above</td><td>0.2%</td><td>0.5%</td><td>0.3%</td></tr>
</table>
Allowable testing measurement error of +/- 3%.
</td>
</tr>
</table>

<u>Rodan Recommendations:</u>

1. Change acceptable testing measurement error of +/- 3% to +/- 1% for kW readings and +/- 3% for kVAR readings between revenue meter and power analyzer (test standard). We recommend changing the acceptable testing measurement error for instrument transformers to +/- 5% (if performed during an in-situ test).

2. Include requirement for minimum 0.25A secondary current (per phase) for in-situ testing purposes.

3. Define accuracy requirements below 1MW.

Reasons:

1. An acceptable testing measurement error of +/- 3% between revenue meter and power analyzer (test standard) for kW readings is extremely high given that the proposed rule calls for meters to have 0.2% Wh accuracy. We are proposing to change the instrument transformer acceptable testing measurement error to +/- 5% (if performed during an in-situ test) due to the difficulty of testing instrument transformer accuracy when the load is fluctuating and readings have to be compared between two separate devices (revenue meter/power analyzer and primary measurement source). Instrument Transformer testing (if performed during an in-situ test) is not intended to precisely verify instrument transformer accuracy, but rather serves as a quick ratio check. Instrument transformer accuracy can only be reliably tested during an outage.

2. When a service is lightly loaded, the measurement error tends to increase. Tests should be performed at as high a power level as feasible to ensure accurate high-end measurement, where the settlement values are greatest.

3. Proposed Section 502.10 does not define accuracy requirements below 1MW.

APPENDIX 11 – INSTRUMENT TRANSFORMER COMMISSIONING, TESTING AND MAINTENANCE

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	Not Defined.	Not Defined.
Summary of Rules	N/A	N/A

<u>Rodan Recommendations:</u>

1. Include rule stating that instrument transformers and secondary circuits must be commissioned and tested prior to energization. Commissioning/Test reports should be documented.

2. Include requirement for periodic testing of instrument transformers based on manufacturers recommendations.

<u>Reasons:</u>

1. This step is often skipped. If there is a problem with the instrument transformer installation, it can lead to large amounts of power being delivered/received to/from the grid, and not being registered correctly until the problem is corrected. Commissioning and Testing of instrument transformers prior to energization can also identify major installation problems and prevent damage to expensive equipment upon site start-up.

2. There are several reasons why Rodan believes Instrument Transformers should be tested periodically:
    a. Primary current and voltage measurements are rarely possible to take in-situ due to safety restrictions.
    b. Secondary/alternate source checks during in-situ testing can not identify inaccurate instrument transformers if the secondary/alternate source shares instrument transformers with the revenue meter, which is very common.
    c. In the event where primary measurements are possible, it’s difficult to accurately test Instrument Transformer accuracy while energized (during in-situ testing for example) because the electrical service loading can fluctuate quickly, and measurements need to be compared between two separate devices (revenue meter/power analyzer and primary measurement source).
    d. Periodic testing of Instrument Transformers can identify potential problems (related to performance and safety) and prevent failures before they happen.

APPENDIX 12 – METERING SYSTEM TESTING: TESTING FREQUENCY/INTERVALS

<table>
<tr><th colspan="3">Existing vs. Proposed Standard</th></tr>
<tr><th>Description</th><th>AESO Measurement Standard (Existing)</th><th>Section 502.10 (Proposed)</th></tr>
<tr><td>Applicable Sections</td><td>APPENDIX 5 METERING SYSTEM IN-SITU TESTING – Section 1: METERING SYSTEM TESTING FREQUENCY</td><td>Meter Testing - Section 9(b)
Meter Testing - Section 9 -Table 2</td></tr>
<tr><td>Summary of Rules</td><td>The MSP must perform a test on a metering system at each of the following trigger points:

Prior to the energization of a new metering system (commissioning tests only).
Within four weeks of the energization of a new or altered metering system.
Upon the change of any equipment associated with a metering system.
Within the time period specified in the following table:

<table>
<tr><th>MW Class</th><th>MW Range</th><th>Testing Interval</th></tr>
<tr><td>A</td><td>< 1</td><td>6 years</td></tr>
<tr><td>B</td><td>1 up to 10</td><td>3 years</td></tr>
<tr><td>C</td><td>10 up to 20</td><td>2 years</td></tr>
<tr><td>D</td><td>20 up to 50</td><td>1 year</td></tr>
<tr><td>E</td><td>50 +</td><td>6 months</td></tr>
</table>

This frequency table refers to individual metering systems.
MW Range refers to the average MW flowing through an individual metering system, where the methodology used to determine the average MW will be documented in the Annual Metering Systems Testing Compliance plan as detailed in Appendix 5 Section 4.
Testing Interval refers to the amount of time allowed between tests of an individual metering system. This time period begins on the first of the calendar month following the completion of a test of that metering system. The next test of that metering system must be completed by the end of the calendar month determined by the table.
</td><td>
The legal owner of a revenue metering system must perform an in-situ test at the applicable testing intervals set out in Table 2, for all revenue metering systems.

Table 2
<table>
<tr><th>MW Class</th><th>Average MW Range</th><th>Testing Interval</th></tr>
<tr><td>A</td><td>< 5</td><td>As per MC requirements</td></tr>
<tr><td>B</td><td>>= 5 and <= 20</td><td>4 years</td></tr>
<tr><td>C</td><td>higher than 20</td><td>2 years</td></tr>
</table>
Note: Average MW Range is defined as the 12-month's MWh divided by 8760(hour);</td></tr>
</table>

Rodan Recommendations:

1. Revenue Metering Systems should be tested at each of the following trigger points:
    a) Prior to the energization of a new metering system (commissioning tests only).
    b) Within four weeks of the energization of a new or altered metering system.
    c) Upon the change of any equipment associated with a metering system.
    d) Within the time period specified in the following table:

MW Class	Average MW Range	Testing Interval
A	<1MW	As per MC Requirements
B	>=1MW and <=10MW	4 years
C	>10MW and <=20MW	3 years
D	>20MW and <=50MW	2 years
E	>50MW	1 year

- This frequency table refers to individual metering systems.
- MW Range refers to the average MW flowing through an individual metering system, **where the methodology used to determine the average MW Range is outlined in APPENDIX 13.**

Reasons:

1. The following are the reasons for Rodan's proposed testing intervals, which are more frequent that what Section 502.10 proposes, and less frequent than the existing **AESO** Measurement Standard:
    a. To prevent long periods of possible inaccurate measurement which can lead to difficult settlements, MC disputes, data estimations and corrections.
    b. To detect unauthorized and access and tampering within reasonable time frames.
    c. For safety. Metering Equipment can experience weather damage, corrosion, water damage, etc.
    d. Utilities charge customers more based on how high their ratchet demand is, because the strain they put on the system during peak periods. Electrical services that have more impact on the grid when they're active should be tested more often.
    e. Proposed Section 502.10's most frequent testing interval of 2 years is not adequate for large sites in excess of 50MW. Measurement problems on sites of this magnitude should be identified within a year.
    f. The cost of annual testing for a large site (>50MW) is arguably negligible in relation to the power production.

APPENDIX 13 – METERING SYSTEM TESTING: MW RANGE/CLASS CALCULATION METHODOLOGY

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 5** METERING SYSTEM IN-SITU TESTING – Section 1: METERING SYSTEM TESTING FREQUENCY **APPENDIX 5** METERING SYSTEM IN-SITU TESTING – Section 4: METERING SYSTEM TESTING COMPLIANCE	Meter Testing - Section 9 - Table 2 (Note)
Summary of Rules	• Existing standard does not dictate how to calculate MW Class, **MSP**s are only required to report how they calculate it.	• Average MW Range is defined as the 12-month's MWh divided by 8760 (hour).

Rodan Recommendations:

1. Rodan proposes the following methodology for calculating MW Range:

   Process:
   1. Calculate sum of all non-zero kWh 15-minute intervals over span of entire year
   2. Divide Result from Step #1 by the total # of non-zero 15-minute intervals
   3. Multiply by 4 to convert kWh to kW (since these are 15-minute intervals)
   4. Divide by 1000 to get MW

Reasons:

1. The following are the reasons for Rodan's proposed MW Range calculation methodology:
   a. MW Range should be based on average demand when the electrical service being metered is active, instead of cumulative annual energy transfer.
   b. The MW Range calculation should not include zero intervals. It should be calculated based on non-zero intervals only. For example, if a 50MW site is delivering/receiving 55MW for half the year, they should be in the >50MW class (E), as opposed to the >20MW and <=50MW class (D).
   c. Using the methodology proposed above will ensure that electrical services which have a high average demand when operational are tested more frequently. This is important because the settlement values are much greater, and the impact on the grid during operational times is more substantial.
   d. For large loads & generator sites, potential measurement issues should be identified as soon as reasonably possible to avoid difficult settlements, MC disputes, data estimations and corrections; regardless of whether the electrical service being metered is inactive for a portion of the year.

APPENDIX 14 – METERING SYSTEM TESTING: IN-SITU TESTING PROCEDURES

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 5** METERING SYSTEM IN-SITU TESTING – Section 2: METERING SYSTEM TESTING PROCEDURES	Meter Testing - Section 9(a) Metering Data Services - Section 5(4)
Summary of Rules	• In-situ testing procedures are outlined in detail. Please refer to the existing **AESO** Measurement Standard **APPENDIX 5** – Section 2: METERING SYSTEM TESTING PROCEDURES for the detailed procedure.	• Requirement that the legal owner of a revenue metering system must ensure that each meter and recorder are tested and sealed as per Measurement Canada requirements. • Requirement that the legal owner of a revenue metering system must check the **PT** and **CT** ratio, as well as metering data against any available second source data at commissioning date to ensure reasonable match between them. **(Listed under Metering Data Services – Section 5(4), instead of Meter Testing – Section 9)**

<u>Rodan Recommendations:</u>

1. Clearly define in-situ testing procedures that align with the in-situ test record requirements proposed in **APPENDIX 17**.

2. Differentiate between meter reverification and in-situ testing. Section 9(1) in the proposed Section 502.10 attempts to address meter reverification and in-situ testing in the same section.

3. Include requirement that in-situ tests must be carried out with a test standard power analyzer that is traceable and annually certified.

4. Move comments about **CT**/**PT** ratio checks and secondary source data checks from 'Metering Data Services – Section 5(4)' to 'Meter Testing – Section (9)'

<u>Reasons:</u>

1. In-situ testing procedures should be defined to **AESO**s preference to ensure that **MSP**s and legal owners are performing tests to a set standard. Without any testing procedures or requirements, **MSP**s and legal owners could argue that a simple spot check against a secondary/alternate source is sufficient and constitutes an **AESO** approved in-situ test. Measurement Canada has a variety of documents relating to metering installation technical requirements but most steer clear of testing requirements. Introducing a testing procedure will also protect legal owners in cases where they contract an **MSP** to perform this work. Legal owners can be assured

that testing is being carried out to an **AESO** specified standard. Defining these critical procedures will promote system-wide consistency.

2. These two separate testing regimes should be independently clarified.

3. For reliable in-situ testing, it's important that a traceable and annually verified test standard power analyzer is utilized.

4. These points do not apply to Metering Data Services. They should be moved to the Meter Testing section.

APPENDIX 15 – METERING SYSTEM TESTING: IN-SITU TESTING REPORTING REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 5** METERING SYSTEM IN-SITU TESTING – Section 3: METERING SYSTEM TESTING REPORTING	Meter Testing - Section 9(c) - (e)
Summary of Rules	• Requirement that test forms are to be submitted to **AESO** by end of the quarter following the month in which test was performed (This form is not intended to replace the detailed metering in-situ test records used by an **MSP)**. • Requirement that test forms are to be submitted to **AESO**. • Requirement that **MSP**s are required to use the test form available on the **AESO** website. • **AESO** test form filing requirements outlined.	Requirement that the legal owner of a revenue metering system must: • provide written test results to the **ISO** for any test required in subsection 9 (a) or (b) that indicates an error of measurement exceeding 3%; • at the request of the **ISO**, undertake and complete in-situ tests on the metering equipment and report to the **ISO** within thirty (30) business days, or within a mutually agreed time frame, of receiving such a request; and • file with the **ISO** an annual report of outstanding un-tested meters in the previous year, annual failures tests, and a mitigation plan, within the first quarter of the next year.

<u>Rodan Recommendations:</u>

1. Include requirement to provide written test results to **AESO** for all in-situ tests, regardless of whether they exceed the acceptable error of measurement.

2. Define what constitutes acceptable 'written test results'. We recommend creating a standardized form to be made available on the **AESO** website. The form that is to be submitted to the **AESO** for test results does not need to be as comprehensive as the in-situ test record to be maintained by **MSP**s and legal owners (See **APPENDIX 17**).

3. Define **AESO**s preference for the method of submission of test results (Example: Email to specified address).

<u>Reasons:</u>

1. It is difficult for the **AESO** to verify whether an in-situ test was carried out if there is no requirement for **MSP**s and legal owners to report passed in-situ tests.

2. Proposed Section 502.10 outlines a requirement to provide written test results to the **AESO** but does not define what constitutes an acceptable submission. If a standardized form is created, **MSP**s and legal owners will have a standard set of requirements to refer to.

3. Proposed Section 502.10 does not outline the method of submission for test results.

APPENDIX 16 – METERING SYSTEM TESTING: COMPLIANCE AND ENFORCEMENT

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 5** METERING SYSTEM IN-SITU TESTING – Section 4: METERING SYSTEM TESTING COMPLIANCE	Meter Testing - Section 9(e)
Summary of Rules	• Timeline for submission of compliance plan clearly defined (between Oct 1st and Dec 31st) outlined. • Requirement to provide list of all metering systems that the **MSP** is responsible for. • Requirement for **MSP** include specific information about each **RMPID** an **MSP** is responsible for on the compliance plan submission, such as: **RMPID**, installation type, MW Class, recent test dates, indication of any metering systems that will be out of compliance by end of year of filing and explanation of plan to bring into compliance, description of testing procedures and explanation of any procedures that differ from those described in Appendix 5 Section 2 of the existing **AESO** Measurement Standard. • Requirement for **MSP** to describe methodology used to determine MW Class. • Requirement to submit information electronically in a standardized form available on **AESO** website. • **AESO** requirement for responding to **MSP** and EUB no later than March 1st of the following calendar year outlined.	Requirement that the legal owner of a revenue metering system must: • file with the **ISO** an annual report of outstanding un-tested meters in the previous year, annual failures tests, and a mitigation plan, within the first quarter of the next year.

<u>Rodan Recommendations:</u>

1. Include requirement for **MSP**s and legal owners to include the following information of their annual compliance plan submission, for each **RMPID** they are responsible for:
    a. **AESO RMPID**
    b. Installation Type
    c. MW Class
    d. Recent test dates
    e. Indication of any metering systems that will be out of compliance by end of year of filing and explanation of plan to bring into compliance.

f. Description of testing procedures and explanation of any procedures that differ from those specified by the **AESO** in new Section 502.10.
g. Description of methodology used to determine MW Class.

2. Define method for submission of compliance plan to the **AESO**.

3. Define acceptable format of compliance plans. We recommend creating a standardized form to be made available on the **AESO** website.

Reasons:

1. Proposed Section 502.10 does not list any requirements to include pertinent information about each **RMPID** that an **MSP** or legal owner is responsible for. Under the proposed rule **MSP**s and legal owners are only required to include outstanding un-tested meters in the previous year, annual failures tests, and a mitigation plan. We believe more comprehensive submission requirements will result in greater compliance to the rules and will be of benefit to the **AESO** because submissions will be consistent across all market participants.

2. Proposed Section 502.10 does not define the method of submission for annual compliance plans to the **AESO**.

3. Proposed Section 502.10 outlines a requirement to provide an annual report to the **AESO** but does not define what constitutes an acceptable submission. If a standardized form is created, **MSP**s and legal owners will have a standard set of requirements to refer to which will promote system-wide consistency.

   All the recommendations included in Appendix 16 will be of benefit to the **AESO** for auditing purposes.

APPENDIX 17 – METERING SYSTEM TESTING: RECORD MANAGEMENT REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 5** METERING SYSTEM IN-SITU TESTING – Section 5: METERING SYSTEM IN-SITU TEST RECORD	Meter Testing - Section 9(c)
Summary of Rules	• In-situ test record requirements are clearly outlined. Please refer to existing **AESO** Measurement Standard **APPENDIX 5** – Section 5: METERING SYSTEM IN-SITU TEST RECORD for the detailed list. **Note:** This section refers to the in-situ test record to be created and maintained by **MSP**s and legal owners and is much more comprehensive than what Rodan is proposing for the submission of test forms to the **AESO**.	Requirement that the legal owner of a revenue metering system must: • provide written test results to the **ISO** for any test required in subsection 9 (a) or (b) that indicates an error of measurement exceeding 3%.

<u>Rodan Recommendations:</u>

1. Include required information to be included in the metering point in-situ test records that are to be maintained by **MSP**s and legal owners. Rodan recommends the following:
    a. Date test completed.
    b. Name of person completing the in-situ test record.
    c. Measurement point identification.
    d. Metering point identification.
    e. Meter Data: Serial #, Make, Model, Ampere rating, Voltage rating, # of Elements, Kh, Kp, Multiplier, Seal Date.
    f. Instrument Transformer Data: Serial #, Make, Model, Voltage Class, Ratio, Accuracy
    g. Metering Equipment Physical Checks:
        i. Meter: Seals, Wiring, Displays.
        ii. Recorder: Seals, Wiring.
        iii. **CT**s: Wiring, polarity, other checks.
        iv. **PT**s: Wiring, polarity, other checks.
    h. Operational Checks
        i. **CT**s: Measure secondary current and using the **CT** ratio, calculate primary current. Compare this primary current with primary current from other source if available and calculate % error. If current is stable, the acceptable error would be +/- 5%.
        ii. **PTs**: Measure secondary voltage and using the **PT** ratio, calculate primary voltage. Compare this primary voltage with primary voltage from other source if available and calculate % error. The acceptable error would be +/- 5%.
        iii. Measure W, Wh, Var, Varh, pf, Q, Qh or other quantities (as required) in each applicable direction and compare them to the equivalent quantities measured with the field metering test

standard. Calculate % errors. If the load is stable, the acceptable error between the meter and the test standard would be +/- 1% for kW readings and +/-3 % for kVAR readings (**See APPENDIX 10**).

i. Recorders: Check the recorder for accurate pulse recording.
j. Vector Checks: With phase A as reference, at the meter test switch, check voltage and current vectors for proper phase sequence and direction of measurement.
k. Communications: Verify that the Metering Data Provider can successfully poll the meter/recorder and successfully collect metering data.
l. Data System End-to-End Test:
    i. Verify that the units of measure for each channel of the meter correspond to the same units of measure for each channel collected by the data collection system.
    ii. Verify that the interval energy data collected from each energy channel by the Metering Data Provider is equivalent to the difference between the corresponding energy register values over one or more consecutive intervals.

2. Include requirement for **MSP**s and legal owners to maintain test results for no less than six years.

Reasons:

1. Without a clear definition of test record requirements, legal owners and **MSP**s could argue that no internal record needs to be produced and maintained. Defining the requirements ensures that all **MSP**s and legal owners are using a similar format for in-situ test records.

2. Proposed Section 502.10 does not include a requirement or timeline for storing/maintaining test results. If the **AESO** requires this data in the future, its pertinent to define a minimum storage timeline for test records.

Both recommendations included in Appendix 17 will be of benefit to the **AESO** for auditing purposes.

APPENDIX 18 –END TO END, ON-SITE COMMISSIONING PROCEDURES

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**APPENDIX 4** END-TO-END COMMISSIONING PROCESSES 6.3 SYSTEM REQUIREMENTS (c)	Not Defined.
Summary of Rules	• Flow chart outlining End-to-End commissioning process for a new meter point included. • **MSP** requirement to ensure that all the required metering system(s) are installed and operational prior to the operation of any power transmission equipment that would cause active energy or reactive energy to be transferred in a manner that would otherwise have been registered by the metering system(s) had it (they) been installed outlined.	N/A

<u>Rodan Recommendations:</u>

1. Include a summarized and easily understandable End-to-End commissioning process for new meter points. This could be in the form of a sequential process list, or a flow chart similar to the one in **APPENDIX 4** of the existing **AESO** Measurement Standard.

2. Include requirements for initial commissioning of revenue metering systems which should occur *<u>prior</u>* to site energization. Including revenue meters, auxiliary equipment, instrument transformers (See **APPENDIX 11**) and communication equipment.

<u>Reasons:</u>

1. Providing an overall End-to-End commissioning process will help ensure that all necessary steps are taken by **MSP**s and legal owners prior to site energization.

2. This step is often skipped. If there is a problem with the installation, it can lead to large amounts of power being delivered/received to/from the grid, and not being registered correctly until the problem is corrected. Commissioning and Testing prior to energization can also identify major installation problems and prevent damage to expensive equipment upon site start-up.

APPENDIX 19 – MPDR REQUIREMENTS

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	**3.3.1 Measurement Point Definition Record** **APPENDIX 9** MEASUREMENT POINT DEFINITION RECORD PROCESSES	Measurement Point Definition Record - Section 3(1)-(6) Revenue Metering System Information - Section 8(a)-(b)
Summary of Rules	• Flow chart outlining general process flow associated with the development and management of an **MPDR** included. • **AESO** responsibilities for operational processes, procedures and processes relating to **MPDR**s outlined. • Key terms and acronyms included in **MPDR** defined.	• **ISO** responsibility to develop and maintain **MPDRs** outlined. • Requirement for legal owner to provide **ISO** with necessary information to create an **MPDR** (Only listed requirement is a Single Line Diagram). • Requirement for legal owners to install and operate a revenue metering system in accordance with the **MPDR**. • Requirement for legal owner to provide **ISO** with information in writing of any modification to the metering system for any metering point associated with a measurement point that would result in changes to the associated **MPDR**.

Rodan Recommendations:

1. Include a more comprehensive list of required information that an **MSP** or legal owner must provide to the **AESO** in order to create an **MPDR**. If a single line diagram is the only requirement, there should be a list of minimum information the single line diagram should contain.

2. Define key terms and acronyms on **MPDR**s that are not already defined in AUC Rule 021. Consider adding a reference to AUC Rule 021 in the Section 3 (**MPDR**) of proposed Section 502.10.

Reasons:

1. Single line diagrams alone are not always adequate to create an **MPDR** if critical information is missing (Example: **CT** effective polarity).

2. Section 502.10 does not define the key terms, acronyms and contents of an **MPDR**. There is also no reference to AUC Rule 021 in Section 3 (**MPDR**) of proposed Section 502.10. Rodan frequently receives inquiries from Market participants asking what these key terms and acronyms refer to.

APPENDIX 20 – TREATMENT OF METERS AND INSTRUMENT TRANSFORMERS NOT APPROVED OR DISPENSATED BY MEASUREMENT CANADA

Existing vs. Proposed Standard		
Description	**AESO Measurement Standard (Existing)**	**Section 502.10 (Proposed)**
Applicable Sections	6.3.3 Meter 6.3.4 Recorder	Meter – Section 7 (a)
Summary of Rules	• Approval under Section 9(1), Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act subject to the terms and conditions of any applicable dispensations(s) listed as requirement. • Approval under Section 9(1), Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act subject to the terms and conditions of any applicable dispensations(s) listed as requirement **Note:** No rule about treatment of equipment not approved or dispensated by Measurement Canada outlined.	• Measurement Canada approval, verification, re-verification and sealing in accordance with the Electricity and Gas Inspections Act of Canada subject to the terms and conditions of any applicable dispensation agreement listed as requirement. **Note:** No rule about treatment of equipment not approved or dispensated by Measurement Canada outlined.

<u>Rodan Recommendations:</u>

1. Consider implementing a program/policy to replace, approve, or dispensate instrument transformers and meters not approved or dispensated by Measurement Canada within an **AESO** specified time frame.

<u>Reasons:</u>

1. Implementing a program like this will ensure that all revenue metering equipment in Alberta is Measurement Canada approved or dispensated, in accordance with Federal Law.

APPENDIX 21 - ACRONYMS

MSP – "Meter Service Provider"
MDM – "Meter Data Manager"
AESO – "Alberta Electric System Operator"
MPDR – "Measurement Point Definition Record"
CT – "Current Transformer"
PT – "Potential Transformer"
RMP – "Real Meter Point"
VMP – "Virtual Meter Point"
RMPID – "Real Meter Point Identifier"
ISO – "Independent System Operator"