ISO-NE OP18 Work Group Feb 26th, 2014 Meeting Minutes (r0)

**Web Conference Scheduled 9:30am to 3:30pm on WebEx**

**Agenda:**

**1. Introductions, Meeting Roles, Discussion of Agenda and Minutes of Last Meeting**

**2. HQ HVDC metering update** – Alan Salk (NGrid), Tom Succi (UI) & David Santa Maria (NU)

Annual Field Testing Guide & Commissioning Testing Guide

The ISO requires the telemetry (RFL – Realtime data) on comm infrastructure that is owned by the utility.

Other concerns: Validation of data (pg .6, section B.5), diagnostics. Issues w/ Optical CTs previously discussed as well

The load profile versus accumulated energy check on IX.D.5 will not be done but the A (main) & B (check) meters will feed A (main) & B (check) pulse recorders. The data on the 2 recorders will be compared against each other.

**3. Generator Station Service Metering** – Jeff Carrara (VELCO), Chad Nelson (ISO) & ???

Discuss revised diagrams and verbiage to discuss key metering and telemetering aspects of a single generator asset following last meetings discussions. Key discussions include station service attributable to a generator outside the main point of interconnect (or PTF boundary) and depending upon how far outside the POI, or its significance to the settlement/telemetry for thermal ratings and losses between its actual POI and the generators main POI, whether it will be netted out like D (from settlement, telemetry and capacity) or like E (only netted out of capacity). Market Rule 1 Manual M28 12.2.4 applies but what guidance does it give (if any to this question). The key reason for revising / expanding appendix D is to make it clear what options / requirements apply for generators and generator interconnects to TO/DPs for revenue metering and telemetering.

If the E load (in VA) was 5% (at max) of the lowest rated component’s rating (between its POI and the Gen’s POI) would it impact the operation or settlement cost? A 5% added flow would add 10% more loss whereas a 2% and 1% added flow yields about 4% & 2% added losses. If the Station service was at full but the interconnecting facilities were not near their rating then the percentage of the SS load would be greater. If the generator is not running than the load should be treated normally for where it is located otherwise (if applicable) it would need to be netted out of telemetry and settlement data submitted to ISO

The proposed appendix D was out for review and we should get feedback or approval at this meeting or soon after to move forward.

**4. Computerized Routines for Telemeter Data Accuracy – Dave LaPlante, Scott Roberge, etc.**

IX.C.1 notes “state estimators or similar software packages that detect and individually inconsistent data values may be used…” for detecting error in place of testing (IX.C.2) - but there is no note giving acceptable tolerances. Methods for checking MW or MVAR data are single point comparison (comparing telemetered data to a state estimator solution) and Bus-Net (netting telemetered data around a bus). For Voltage values single point comparison can still be used otherwise has to be compared against adjacent values.

Pilot language for IX.C.1 was discussed at last meeting and was revised to version 3.4. It is planned that this wording would not be revised in OP18 in this round but instead be used to kick off a pilot project by those wishing to continue or start leveraging IX.C.1 (in place of the field testing noted in IX.C.2). If we have acceptance from the group this topic will be closed for future meetings except to discuss the pilot as necessary.

To discuss progress so far for those which have something to show. Talk about other implementations that are being scoped or in process development.

**5. Miscellaneous Discussion, OP18 Document Work, Committee Discussion, etc.**

**Sub-hour Metering Intervals:** any update?

**Reviewing OP18:** All of OP18 has been reviewed and revised by the group as of last meeting now so it is up to the TOs to make sure we are ready to send the remainder of changes to the ISO approval process.

**6. Summation: Plans for continuation of discussion & next meeting(s)**

**Adjourn**

**1 Introductions, Meeting Roles and Discussion of Agenda**

**Voting Members:**

CMP: Scott Roberge –present -

Emera: John Doyon – present –

ISO-NE: Brock Nubile –present –

NGrid: Alan Salk - present –

EE\*: Bob Bobarsky -absent \*: Eversource Energy

UI: Clifford Branzell - absent

VELCO: Jeff Carrara (chairman) – present

**Other Participants:**

ISO-NE: Chad Nelson – present

John Caravaca – present

John Socha – present

NGrid: Michael Crowley – present

EE: Dave LaPlante – present

Vinni O’Connell – absent

Greg Pivin – present

Tom Cahill – present

Brian Whalen (NStar) – present

UI: Tom Succi – present

Tony Napikoski – present

Bob Pellegrini - present

**February minutes motioned by Alan (NGrid) 2nd’d by Tom (UI) - CMP, Emera, ISO, NGrid, EE, UI, VELCO**

**2. HQ HVDC metering update** – Alan Salk (NGrid), Tom Succi (UI) & David Santa Maria (NU)

**February 2015:**

1. Some questions came up from the group that will be sent to HQ (see below)
   1. Strike Settled, any time frame for commissioning?
   2. Status update on RFL installation for real-time data.
   3. Question - does any comparison take place between the dc meter register read and the recorder?
2. HQ has completed changes and requests to commissioning and testing documents.
3. Discussion held on real time transmission to ISO from HQ - will be via RFL. ISO will investigate at their end the status of this installation and also what the use of the data will be as the RFL data from Sandy Pond should be the operational data needed.

**December 2014:**

A brief project update was given based on the AOC meeting held a couple weeks ago which indicated that a strike is still in progress, and no date was given as to when the replacement high voltage IT will be installed and when the commissioning/validation period will begin.

Presented to the group for review HQ's most recent version of the "Annual field testing document" & "Commissioning testing document". These new documents have added the column for the "Standard meter reading" to all of the test equation tables. They also have added a form to document when a meter is taken out of service for testing which includes the meters serial number and out reading. HQ also indicated that upon a meter being taken out of service for testing the telemetry will automatically switch between A & B system so that no interruption will occur.

Based on discussion at this meeting, HQ will be asked: (a)  to update their "Meter error equation" in both documents to replace "reference dc power" with "Standard Meter Reading" (b) indicate in the documents that data missing while a meter (A or B system) is being tested will be patched from the readings of the in service (A or B system) meter. (c) will question HQ on test jack as presented in photo if permanent or temporary and how they will validate when the meter is wired back into service if correct. (d)

**November 2014:**

Test results for std meter missing from procedure.

How to apply test load?

Taking meters out of system under test.

**September 2014:**

OP18 VII.A. ANSI Standards – Updated for DC metering – No additional comments

Section IX.D. Watt-Hour Meters. b) – Updated for DC metering – No additional comments

In IX.F it is already mentioned that the standard used for testing watt-hour meters needs to have a 0.1% or better accuracy whereas for telemetry and instrument transformers needs to twice as accurate. Follow up with HQ.

Annual testing – under normal modes of operation – normal operation needs to be defined

Same device that is utilizes and reports telemetry and revenue metering used in same circuit needs to be able to maintain telemetry during test (Note to NU – EML: may need additional test equipment and standards)

**August 2014:**

Missing from field test procedure…

1. Adjusting meter test recorder data after test
2. Adjusting backup meter data after test
3. Telemetering Watt/VAR device, AB, throw-over switch during test

Accuracy requirements need to meet or exceed ANSI standard C12.

**July 2014:**

See 6/20 email…The 3rd calibrated meter will be used for calibration checks for each in service meter (A&B) in turn. Field test DC meter in series-parallel with standard, compare outputs, a recorder will be in circuit to see target test data for comparison. Telemetry can be sourced from either meter so during test the meter not under test will be used. Test data will be adjusted in MV90 as part of the test procedure, no test mode on device, the meter not under test will be used to capture the correct registration. Instructions for testing devices will be provided. The 4-normal modes of operation (compensation equations), will be tested annually at 10 & 100% nominal current levels similar to AC meters LL & FL. Whereas the commissioning test will test all 12 equations HQ working on connecting to ISO via microwave

Telemetry data must be provided by utility owned telecom communications (VIII.2). The approval of the test procedure should predicate standard witness tests (VELCO & NGRID, etc…) it may be worthwhile to invite the other utilities as well. Test switches vs quick connectors should be looked into for testing purposes, allow isolation, safety and reduce risk of disrupting other devices, while device is under test (another potential discussion for OP18 revision).e

**June 2014:**

No update since last meeting. Last asset owner meeting HQ acknowledged that they need to work with OP18 to work on the open items.

**May 2014:**

HQ, NSTAR, NU and UI meeting to discuss testing and commissioning, Validation methodology, field testing… Refer to HVDC Meter Testing Document provided by Alan which is an outline for their meeting with HQ. Per the last asset owners meeting, HQ will be calling us for a conference call to discuss these items, Alan will notify the group when this is scheduled so whoever wishes to attend can call in. One issue is that Tom did not notice anything in the documentation for a test mode, so if the (2) meters talk to each other for validation a procedure will be needed for putting test load on the meters

Is enough information available and acceptable to include in OP-18 for testing? We have a good idea but will wait to get agreement by all parties on testing (as noted above).

**March 2014:**

Real-time should be via RFL 9800 system, ICCP is only backup source of real-time data

For the annual testing & equations they did only what we asked for but not as far as we expected…

**February 2014:**

Data request from HVDC from last meeting has not been received yet, so nothing new to report for this meeting.

Tom provided a email clarification after last meeting explaining that the dc meter does receive a external contact closure indicating what operational mode the meter is in which (along with the values of voltage and current metering inputs) tells the meter which loss compensation formulae to utilize.

Of the 12 modes of operation only a small subset are contractual the rest are drastic action (small time frames) The group is in agreement that we would not require they test all 12 modes/formulas for loss compensation in all possible operational modes. Thinking they should bench test in the shop all modes and document prior to the meter going into the field, and in the field have a short list to be determined for annual field testing.

**January 2014:**

Normand Girard and Patrick Roy were on the call representing HQ

Discussed the dc meters to be used for testing, they will have three meters, two for testing and one as a reference. The meters will be tested/calibrated annually at the Canadian equivalent lab to our USA NIST.Discussed the test points on the document presented by HQ which have values at nominal, 150%, 10%, and 50%. We are in agreement with these test points.

Discussed testing in the calibrated mode. We learned today that the meter autosenses inputs and determine what mode of operation the dc line is in and then uses the appropriate compensation. HQ intends to test and verify all modes of operation in the meter in the lab on the bench and then test accuracy in the field in only one mode. Also discussed how many modes (12?) and the merit of testing and the time involved in checking all possible modes. Generally the line only operates in a couple of modes. Generally consensus that some level op compensated field testing should take place as currently is required within OP18 for an AC meter. Have requested that HQ provide us with a list of the inputs that will trigger the different modes/compensations in the meter.

Asked HQ about the intended comm. path for the real time data from the new meters to ISO. They will check with their control group and get back to us.

Patrick and Normand will get on next month’s call for further discussion.

**December 2013:**

Most of the discussion will be made in the January meeting when Tom and potentially HQ may be able to chime in. Otherwise it was discussed that HQ had done commissioning checks in October for which they wished to start the clock. NGrid/VELCO had asked for commissioning information as we were not invited to witness the commissioning checks and HQ responded that they need to convert documentation from French to English and will provide at that point. Also it was noted that the current implementation does not automate the energy check noted in OP18 but will compare the A and B reads against each other which needs to be evaluated.

**October 2013:**

1) This meetings discussion was limited to the meter/recorder and field testing requirements, did not discuss the IT's.

2) Discussed the operation of the meter indentified that the inputs to the meters are dc voltages for both current and voltage with 5 volts representing the full scale voltage of 450kV, and 5 volts representing the full scale current of 2250 amps.

3) Discussed potential issues of how to field test, traceability of source to NIST. Possible have a third meter as a reference and or bench test then swap out at site. These issues are more for NG as the witness to testing versus this group making the necessary changes to the OP to accommodate the dc metering system.

4) Agree that the test points will be +/- full load, 150% full load, 10%, and 50%. Compensation tests other than the normal condition could be limited to full load (100%) and light load (10%).

5) Reviewed and discussed the proposed OP edits.

6) Agreed that the test would include the test points in (4) above and would be for all modes of meter operation.

**September 2013:**

Just before the meeting HQ had submitted a proposed “Annual Field Testing” document. It was noted there were some issues with the diagram and the document hasn’t had much chance for review prior to the meeting. It was mentioned again that the document make no mention of the telemetry component which is also required along with the utility owned communications circuit needed to transmit that telemetry to the ISO.

**June & July 2013:** No new information at this time; still pending testing documentation from HQ.

**April 2013:**

Canadian standards pending approval of testing plan. Field testing procedure pending. Waiting for CSA. Tom Succi provided documentation on the data recorder for the DC metering that has MV90 TIM for collection and validation of data.

DC-CT measuring device damaged in Flash testing due to insulator being porcelain. Insulator change to composite being proposed. DC metering equipment accuracy and testing needs to be re-evaluated.

Per Alan, comply with OP-18 accuracy requirements. One year validation using metering, DC-CT vs. existing measuring equipment. DC-CT not available, interim CT is being proposed for validation,

Per Tom, We need test procedure prior to approval.

Alan’s Questions to HQ:

* What are the specs and accuracy they want to use for the interim CT?
* Spare available? If not, how long will interim CT be used?
* Will this scenario with interim CT accommodate all compensation scenario’s?
* What testing procedure will be used?

Optical CT’s not been successful through experience for metering per OP-18 committee.

While the people on the subcommittee had expected new information by this meeting it had not come so there was nothing new to discuss

**See previous minutes for earlier detail**

**3. Computerized Routines for Telemeter Data Accuracy**

**February 2015:**

Discussed further, not everyone up and running fully yet… Any details of note to add?

**December 2014:**

Brock to check with ISO on auditing penaltys and/or ties to NERC

Had some discussion over data sharing given CEII. Each participating TO should check with their CEII SME on this topic. There are options to share the data without it being a concern such as NU’s example of generalizing the various substation names so the data can’t be tied back.

**November 2014:** Discussed Pilot, what TO plans may be and to discuss some data and practices next meeting

**September 2014:**

Pilot IX.C.1 language:

Section a. – NU has concern with bullet three, the voltage variances between three locations may give an erroneous average value. New language added to reference other options for comparing less than three bus voltages at same voltage relationships.

* + - * The average of all non-zero telemetered voltages that are phase-phase\* on the same nominal voltage level at the substation. Busses at the same voltage level that are not tied should be treated separately.
        + When less than three voltages (of comparible phase relationship) are measured at the same substation bus then additional points of reference are needed for comparison. Other points of reference could include, but not limited to, adjacent bus voltages, nearby scheduled voltages or bus voltage in a state estimator.

Section b. – Included percent tolerance for using largest full scale value

* 1. The tolerances for acceptable MW, MVAR and kV telemetered quantities are as follows:

Watts: +/- 10 MW or +/- 4.5% of the largest full scale value (whichever is smaller)

VARs: +/- 30 MVAR – for bus net will determine during the pilot whether a percentage of full scale, like on MW, could also be used.

Waiting for pilot program confirmation from UI, NGRID, CMP, etc…Dave L. to send out template used by NU.

**August 2014:**

Proposed IX.C.1 version 3 was developed on a July 30th conference call with members from the TOs. On that call it was discussed to use this language for a pilot instead of incorporating it into OP18 at this time. As an action from that call on a later call closer to the meeting data Jeff and Scott discussed the MVAR exception for SE and determined that if the MW and MVAR is derived/measured from the same device and the MW is being checked by SE that the MVAR quantity can be exempt from the MVAR check which lead to version 3.1. Since this principle also applies to Bus-Net a version 3.2 was developed to attempt to simplify the MVAR check exemption of any method.

The revised language was discussed at the August meeting as well as considering it as a pilot.

Cliff B (UI) proposing to use the revenue meter for comparison against the telemetering device as another alternative method for the quantity check. Concerns with loss of phase (V or I), would need monitoring for loss of phase detection, access to real time data, comp and uncomp data is available… This option was written in for version 3.3.

No all TOs had their related people in the conversation to determine the timeframe for implementing pilot program so it would be related to them and discussed at next OP meeting. It was expected that the pilot could start in January 2015 and run for a year. Also if need be points could be prioritized by voltage: Data points from higher voltages are more likely to have higher levels of MW and MVAR difference. There was discussion about whether the pilot should be run with the revised language in OP18 or have the pilot run from the language in the separate document allowing us to only change the language once if anything needs to change following the pilot.

**July 2014:**

Bob Peligrini (UI) – Uses state estimator for reporting to ISO.

Proposal is to use Bus NET check every month with new thresholds in lieu of periodic testing. UI will need PI interface with CONVEX.

UI, CMP and others need additional time to review the proposed documentation (2 versions of IX.C.I as proposed by Jeff and Dave) in order to devise a realizable plan of action that suits each company and address any concerns with the proposed wording, method (State estimator, Bus NET, etc…), tolerances ranges, reporting frequency, etc…Each entity will need to establish an auditable procedure, means of archiving data, etc… once this has been agreed upon and accepted by all stake holders.

Subcommittee meeting to discuss further: Jeff(VELCO), Dave(NU), Scott(CMP), Dexter(NGRID), Bob(UI)

**June 2014:**

NU and CMP provided additional data points since last meeting. NU provided 24 individual hour integrated/average data for 3 busses on 2 weeks as a follow-up to daily average mismatch calculations. This included a bus with three 345 kV autotransformers showing a high amount of MVAR mismatch (~17 MVAR for a number of hours). CMP’s datasheet was based upon variation from the state estimator for MW/MVAR and kV. Like NU’s sheet using busnet the MVAR mismatch for CMP using state estimator comparison still has some mismatch to the order of 22 MVAR on the worst base but most are much better

It was noted by John (CONVEX) that State Estimators (SEs) are incorrect at times and require manual intervention. Also people noted that 345 kV autotransformers and GSUs cause a difficultly to discern VAR accuracy. So while SEs can estimate the VARs in a transformer compared to a simple bus-net they have the weakness that the SE solution may be invalid causing incorrect red flags.

Since MW was much more reasonable than MVAR for all utilities for both Bus-Net and SE –AND– since MW and MVAR most often derived from the same measurement device –AND– since such a measurement device would cause error in both MW and MVAR if drift were to occur –THEREFORE– If MW and MVAR telemetered data within a substation are from the same measurement device only MW need be monitored for bus-net or SE single point comparison. If MW and MVAR are measured from different devices on the same circuit then both need to be monitored for bus-net or SE single point comparison.

While the current requirement requires the routing occur once every 6 months it should occur more often to catch more operating conditions of which would ideally catch a peak day. Even on peak most devices would still be far away from the “full scale” discussed in appendix C. It was proposed to have the check done once a month and capture 1 point each hour of that day. In the case of SE single point comparison would require some level or archiving of related solution and telemetry data. It is understood that once a month may mean the 31st of one month and the 1st of the following month. This would not be ideal but for simplicity in language will be left that way and if anything is still more often that the once every 6 months

Thresholds were also proposed.

* MW: +/- 10 MW
* MVAR: +/- 30 MVAR
  + When not provided by same measurement device as MW, otherwise can be ignored
  + Still a wide window but will require significant work to hone down any further.
* For voltage (kV) the thresholds would be different by voltage class:
  + 345 kV: +/- 5 kV
  + 230 kV: +/- 4 kV
  + 115 kV: +/- 3 kV
  + Applicable 69 kV = +/- 2 kV.

Dave LaPlante volunteered to propose wording for OP18 based upon these proposals: MVAR check only required if not measured by same device as MW; check to occur at least every month containing 1 days worth of 24 separate 1 hour samples; See thresholds proposed above.

**May 2014:**

Bus NET examples provided by NU, NGRID and VELCO. As an example VELCO noted its bus-net tolerances of +/- 5 MW/MVAR except for 345 kV MVAR which is +/-10 which works everywhere except for a bus with a large high flow GSU telemetered on the low-side which throws off the bus-net significantly. VELCO was asked if this was a proposal to the group but it was not unless others thought it was reasonable although another example at the meeting would have issues with VELCO’s tighter tolerances. Bus NET thresholds in question, defer decision until CMP provides additional information. CMP proposing more data points throughout year.

State Estimator check for individual single point comparisons versus Bus NET check. Establish tolerances dependent on method. It was thought that single point comparison may be a better method although it is only in 1 way: that it identifies the most likely telemetering point that is in error. Although for thresholds both method have the same issues: They rely on the summation of errors of surrounding telemetry so most likely the thresholds would be the same for both methods.

Everyone will continue to provide additional examples w/o large high flow transformers @ 115kV to 345kV and multiple points (VELCO, NU, NGRID, CMP). Key point is here that some transformers are telemetered on only 1 side yet are used for bus-net for high and low-side busses that they interconnect with so the VARs (and to a lesser point Watts) absorbed by the transformer can vary widely based upon loading. So the idea is to avoid evaluating busses that include meters on a different voltage where the transformer they meter is sufficiently loaded to throw off the evaluation of errors due to the telemetry system.

**March 2014:**

Update on “homework assignment” to gather existing day-to-day variances (single point comparison and/or bus-net) on a select number of 345, 230, 115 & 69 kV busses by which a discussion can be had what variance limits could be set based on either voltage level or metering range of connected circuits.

Dexter (NGrid) not ready to get the data out of the system but within a week or so will have something developed to start looking at this information

Dave (NU) to check with PSNH on homework assignment. Also was asked to run his manual bus-net more often for data for next meetings discussion.

Jeff (VELCO) will also be looking at this as bus nets are now being archived in pi

Asked UI to participate if they have an inkling of interest... (the more data points the better)

Scott (CMP) has not had a chance to start yet but may have information for the next meeting on the subject

**February 2014:**

Voltages from relay may also be positive sequence which adds another variation to compare with ph-ph & ph-gnd values which already may differ more than the tolerances allowed to individual equipment. OP18 prefers ph-ph values although ph-gnd may be used if compensated phase-phase (x √3) but this can lead to issues with computerized routines. Look forward to future meeting for results of bus-net and single point comparison data gathering…

**January 2014:**

Discussion continued on the computerized routine for verifying telemetering system accuracy. A meeting was scheduled for Feb 6th 2014 for this specific topic for SMEs to have a focused discussion on this topic.

**December 2013:**

Talked over NU’s “homework” excel sheet looking comparing the 1.5 MW/MVAR per circuit bus-net method to the per circuit MW Allowance method.at an example 345 kV substation with 5 lines and 3 transformers (8 circuits) the 1.5/circuit method would allow a bus net difference of 12 MW/MVAR whereas the individual circuits using the MW allowance method: (+full range) \* (summation of allowable inaccuracies of components) = MW/MVAR error on a reading versus the state estimator calculation. The summation of allowable inaccuracies for a MW/MVAR read would include a transducer (0.25%), a CT (0.6%), a VT (old 1.2%, recent 0.3%) + 0.2% if an A/D on the RTU is used due to use of an analog transducer which yields from a minimum of 1.15% to 2.25%. NU at the 345 kV example bus had full ranges of 900 for the transformers and 5400 and 10800 for the lines. The lines with 10800 would allow from 124.2 to 243 MW/VAR of error on those reads before flagging an issue which seemed to the group to allow a high level of error. Before Scott joined the call it was suggested that we investigate if the 1.5 MW/MVAR per circuit bus net method would be acceptable since it is much more conservative and hasn’t caused NU any heart ache (currently ISO allows a bus net error of 24 MW/MVAR). When Scott joined he was reluctant to agree with this method as the CMP state estimator does not implement a bus net and so it would be added work that would require justitifcation. Also Scott does not expect to be able to respond to the MW tolerance method either for the January meeting

**October 2013:**

Proposed weekly reporting obligation vs six months, for Option 1 (IX.C.1.). Utilities using RTNET – Need to establish limits and thresholds for inaccuracy percent tolerances. Dave will contact CONVEX for monitoring RTNET and discuss reporting frequency. SUB BUS NET vs FULL SCALE (N\* Highest Full Scale). Utility to report Full Scale range to ISO… Create testing parameters for each options accuracy limits. The accuracy limits for each option need to be established. NU - CRS 13, procedure on checking tolerance using calculated comparison of voltage values between adjacent substations.

PSNH Mismatch in RTnet: +/- 10 for MW & +/-5 for MVAR

The full scale of metering values at higher voltages is greater due to the VT ratios and for bundled conductor may also have higher CT ratios. If a bus net calc were to be done then the appendix C limits would need to be applied to the meter value with the highest full scale value and because 2 values could be out in opposite direction so twice the appendix C value may be needed. Bus Net is one method, the other method is comparing an individual metered value against a solved value which may better verify individual metered values. Each TO using method 1 should look at the largest full scale value for a sample 345, 230, 115 & 69 kV and apply appendix C to derive reasonable thresholds. Also consider weekly instead of every 6 months for the periodicity.

**September 2013:**

Continued discussion on accuracy limits on computerized routines noted in IX.C.1 was discussed starting with what NU (has for their check every January and July.

NU’s (CL&P and WMECO) Procedure summarized for Watt and VAR telemetry checks take a substation bus (radial, ring, breaker-and-a-half at the same voltage) with N circuits connected to it. Net each the MW and MVAR readings from all those circuits and the differential error left over is allowed to be N \* 1.5. For the voltage check compare adjacent voltage values either at the same station or an adjacent station and the allowable difference for 69 kV is 2kV, for 115 kV is 3 kV and for 345 kV is 7 kV. In both cases it is not just the error of the transducer (or equivalent measurement device) but also the allowable error of the CT, VT and CPU interface that may apply. For example with the current allowances a MW or MVAR point is effected by the CT (0.3%) and VT (0.3% although previously 1.2% which applies to older VTs) errors plus a transducer (0.25%) or digital relay (0.5%). For a transducer the mA or V is then measured again at the RTU (CPU Interface, 0.2%). 0.3 + 0.3 + 0.25 + 0.2 = 1.05% (previously 1.95%). A voltage value would not be affected by the CT so 0.75% (previously 1.65%) would apply.

This same discussion is needed for the checks accomplished automatically by state estimators (used by CMP and NU-PSNH) which each may use different algorithms for deriving a %error. CMP and PSNH need to work with the vendors of their state estimators as to the method used to derive the %error so a reasonable method can be created to derive an accuracy limit.

**July 2013:**

Proposed changes to last paragraph in section IX.C.2. – Change to Digital telemetry (ADC) exempt from periodic testing requirements. (Testing Frequency = 4 yr’s), new verbiage will be presented at next meeting.

**4. Generator Station Service Metering** – Don Bergeron (NU), Jeff Carrara (VELCO) & Chad Nelson (ISO)

**February 2015:** Nothing new yet, looking for TOs and MRWG to review and comment

**December 2014:**

Still looking for input on Appendix D from TOs to move forward

Chad Nelson to take Appendix D to MRWG

**August 2014:**

There were comments provided by NU/PSNH (Aug 11th email) that need some attention, they were reviewed at the meeting. Still looking for comments from others and will need to have more people involved to move this forward.

Dynamic fixed allocation method will be omitted from appendix D and won’t be used going forward. Older existing facilities will be grandfathered. Other acceptable methods can be used in the same manner as the dynamic-fixed allocation method, such as, the fixed allocation method.

ISO (Chad Nelson) to review Figure 6 changes for combined cycle generators.

Pending comments and feedback on appendix D changes from OP working group.

**July 2014:**

**Follow up with Chad Nelson for omitting dynamic fixed allocation method. Each TO (and ISO) still needs to review the proposed Appendix D.**

**June 2014:**

Review terms and conditions on metering concepts for generators and station service. ISO to confirm if any of the multiple generator asset methods are unacceptable (such as dynamic fixed allocation method). Each TO needs to continue to push on reviewing the proposed appendix D.

**May 2014:**

Review and provide feedback on last draft of Appendix D. Decision needs to be made to move forward with update to OP18 appendix D.

Dynamic fixed allocation method not accepted by ISO…Concern: is not knowing the condition of the generators (online, offline, at what capacity, etc…) in settlement systems like in SCADA. Up for discussion on pro’s and con’s.

**March 2014**: quick update: Don provided some revisions to Appendix D . Diagrams need more work. Jeff and Don to continue work.

**Oct & Dec 2013 & Jan & Feb 2014:** Not discussed as Don was not in attendance

**September 2013:**

As tasked at last meeting Jeff was to come up with thresholds for significance of E type loads (generator station service loads connected outside the generators main point of interconnection, POI) as they relate to their negative effect on telemetry which would need to net the E type loads out of their actual connection points (if those points are reported to ISO) and into the generator’s POI telemetry.

Jeff proposed that if this E type load was only 5% of the rating of the circuits where it shares the line and/or transformer components with other loads to the generator’s POI. For example at a large generator where the aux station service is connect to the 115 kV which connects to the 345 kV through a 448 MVA nameplated autotransformer where both the 115 and 345 kV busses do not limit the rating of the transformer the ~4 MVA of load served is ~0.9% of the rating of interconnecting circuits. This circuit could allow the service to be as high as 22.4 MVA before this load would exceed the 5% significance limit.

Someone else mentioned 10% could potentially be ok as well but the question needs to be posed to ISO (and maybe LCC’s) which would need to evaluate the effect of actual flows versus net telemetered flows being different by 5% of the Normal or LTE rating.

**July 2013 Meeting:** (for item numbers refer to June meeting further below)

Items 1 thru 3 were updated in the proposed appendix diagram provided by Jeff C based on a previous meeting, item 1 was updated further per Don B, “xfmr loss comp” verbiage was included, these particular items were agreed upon by committee members. Follow up discussion for remaining items will be vetted offline via a subcommittee consisting of Chad N, Jeff C, Don B, Vinny O & Bob B prior to next teleconference meeting on the 17th and next OP18 face to face meeting.

Item 4 – Follow up on acceptable netting @ different POI’s? Contractual POI vs PTF (POI) vs NON PTF (POI). Metering Domain vs LMP vs POI. Separate POI exceptions/rules? Provide examples and change language as needed in order to satisfy agreed upon guideline for load(s) associated with an ASSET which are not electrically connected to the same POI as the ASSET…What load(s) should be netted and & not netted according to Market Rules based on an agreed upon perspective of the rules (since there appears to be grey area that is open to interpretation.)? Jeff Carrara had revised diagrams with revised E language noting issues of displaced power flows across a modeled impedance as well as their effects on thermal/voltage limits. Jeff Carrara to propose definite thresholds for “significance” to remove the grey area.

**June 2013 Meeting:** NU provided feedback before the meeting so we started with their points to Appendix D, Figure 3 Definitions & Diagrams:

1. D, E, and F definitions (or note(s)) should state "one or multiple loads represented as single loads for clarity." ***Accepted***

2. B definition should include "running station service" in parenthesis. ***Accepted***

3. D definition should include "common station service" in parenthesis. ***Accepted***

4. E definition can not use "significantly". The definition needs to read "other point or points of interconnection" plain and simple. ***Open item for follow up discussion.***

5. Include a definition or reference a definition for PTF. Both Market Rule 1 Manual M-28 and OP 18 refer to PTF. ***Open item for follow up discussion.***

6. D on Figure 3 can not be netted if the bus is PTF. D in this case becomes E***. If POI = PTF then ???; NET Allowed or NET Not Allowed. Per Chad, “Price is identical if same PTF bus”. Open item for follow up discussion.***

7. D on Figure 3 can only be netted if the bus is Non-PTF and the bus is owned by the generating facility. Ownership change to either Transmission or Distribution prevents netting of load D based on Market Rule 1 Manual M-28 12.2.4(2) "...Generators connected to the non-PTF system must be reported net to the point of interconnection with the utility(s) to which they are directly connected..." We interpret "utility" as Transmission or Distribution. So D becomes E when fed from a bus that crosses Transmission or Distribution. ***Open item for follow up discussion.***

8. We suggest making reference to Market Rule 1 Manual M-28. ***Open item for follow up discussion.***

**See previous minutes for earlier detail**

**5. Miscellaneous Discussion, OP18 Document Work, Committee Discussion, etc.**

**5a. Sub-hour Metering Intervals**

**Nothing new in June through February 2015**

**May 2014:**

ISO Demand Response Program: Implementation ISD June 2017. Need to establish metering requirements for 10 minute reserve. Currently 5 min data is being provided, a 1 minute interval is being proposed. A concern is with the resolution provided by the KYZ pulses provided by the retail meter. It appears for short durations (such as 1 minute) the resolution of pulses from the metering are skewed due to large pulse values. Limitations to the capabilities of the meter may prohibit smaller pulse values due to memory or saturation (overflow).

**Past Meeting Notes:** (nothing new in 2013/14)

Don gave an update from the last Meter Reader Working Group meeting which was mostly that they have the estimated costs from the utilities for the change for them to evaluate the cost-benefit.

It was noted by Alan as previously voiced by others starting at the July meeting that this has an impact on the meter options that are available as many meters while able to do smaller intervals and store the 60 days required by VII.B.5 bullet 3. The expectation is that there are only 2 or 3 meters available that would meet the memory requirement for this

**5b. Review of OP18:** (Detail is covered in the OP18 redline)

**February 2015:** No further changes planned, may submit for ISO approval process at next meeting

**December 2014:** Discussed George Wegh’s (of NU) comments:

* VIII.1 – The working group had changed the should to shall for having 8 hour capability on the batteries. George opposed this new requirement noting it is in NPCC directory 8 for black start facilities only and should not be applying it to all stations. The working group changed the alternative power source from “an independent battery” to “an uninterruptible power source” but otherwise left the “shall” and the 8 hours.
* VIII.1 1st bullet – George noted the “If for some reason” was too open ended following the above noted “shall”. The working group replaced this and the next bullet with new language of a different note:

### All microwave/fiber optic sites should have a battery rated for at least eight hours and a suitable backup power source for extended periods.

### This includes telephone company equipment co-located with Market Participant or Designated Entity equipment.

* VIII.3 – George disagreed with the change the “should” to “shall” for making stations that have 2 battery systems capable of being a power source for the equipment. He noted the NPCC TFSP that they do not want entities tying both systems together. Jeff clarified that the TFSP allows either system to feed the telemetry but should have protection separation (fuses/breakers) that ensure that a fault in the telemetry circuit would not take down both battery systems. The working group reverted back to a “should”.
* VIII.5 – George asks “Are there telemetering systems that are "required" to be redundant? And by who?”. The working group revised the statement removing the “shall” & “that are required to be redundant” reverting it to its original form
* VIII.6 – George takes exception to reporting alarms from telemetry equipment such as a bitronics meter to the LCC. This was left as is.
* VIII.8 – George takes exception to the 8 hour battery (similar to VIII.1) and suitable backup power source for an additional 36 hours. This was moved to sub bullet of VIII.1 and “36 hours” was reverted back to “for extended periods”.

**November 2014:** Reviewed changes

**September 2014:**

**Note (5) proposal has been unanimously accepted.**

Note (5) – The voltage transformers accuracy requirement for security analysis changed from an accuracy class of 1.2 to 0.3 as of the September 17th 2010 revision of this appendix. All VTs put into service after Dec 31st 2012 require the higher accuracy. This VT accuracy requirement change occurred with the addition of allowing digital protective relays which commonly have a wider accuracy specification and as such should only be used with the higher accuracy VTs.

Continue with review:

Section - IX.D.2.a.ii: Include all watt-hour meters (removed “induction”)

Section – IX.D.a.iv.: Delineate induction type from other watt-hour accuracies (change “solid-state” to “other”)

Section – IX.D.b: Changed “permitted for solid-state only” to “not permitted for induction type meters”.

Section – IX.D.b.iii: Removed “solid-state” so that it applies to all meters and removed “or promptly replaced”.

Section – IX.D.4: Changed to reference “non-induction type watt hour” meters with a reordering of the sentence.

Section – IX.D.5: Separate out validation for Real time demand response assets and real-time emergency generation assets.

Section – IX.D.6: No further discussion for now

Section – IX.E. Instrument Transformers: Added reference to ANSI C57.13 although we need to make sure this includes the test code

Section – IX.F Test Equipment: changed “solid-state” to “non-induction type” as well as a should to a shall for watt-hour standards to be certified every 12 months. Added requirement for telemetry standards shall be certified at least once every two years.

No further comment in OP18. Now it is out for TO review prior to filing this part for the ISO process.

**August 2014:**

ISO-NE provided revised wording for Appendix C note 5 which was discussed and pushed back to them.

* + OP18WG draft: Note (5) – The voltage transformers accuracy requirement for security analysis changed from an accuracy class of 1.2 to 0.3 as of September 17th 2010. Any VTs procured after 2012 require the higher accuracy class to account for projects already underway that would have already procured VTs. Also this change occurred with the addition of allowing digital protective relays which are commonly have a wider accuracy specification as such should only be used with the higher accuracy VTs as required for changes since the September 17th 2010 revision.
  + Proposal: Note (5) - The voltage transformers accuracy requirement for security was revised in NERC Standard XXX-XXX on September 17, 2010 from an accuracy class of 1.2 to 0.3. This change occurred with the addition of allowing digital protective relays, which commonly have a wider accuracy specification and as such should only be used with the higher accuracy VTs as required for changes since the September 17th 2010 revision

The NERC reference is unnecessary (and uncertain what reference we would make) but the removal of the middle sentence was accepted as well as the slight modifications to the last sentence.

**July 2014:** Continued wordsmith of OP18. Re-reviewed and further revised Section VIII which included a bit of discussion on telecom equipment operating temperature range, utility owned telecom facilities and a bit more about backup power and reporting of alarms .

IX.B – removed example list of meters, chart recorders and computer outputs. Also removed testing of all circuit breakers….

IX.C covered by other initiative

IX.D.ii should potentially cover more than just induction meters

IX.D.iii & iv changed practicable to practicle

Next meeting will review above notes and continue with remaining sections

**June 2014:** Worked on VIII. Will check through it next meeting and then continue with IX.

**May 2014:**

No comments on V.D or V.E

Section VI “METERING FOR POWER FACTOR MEASUREMENT PURPOSES” seems to be unneeded. Each TO to look into this and get back with the group

Section VII “EQUIPMENT STANDARDS FOR NEW AND UPGRADED INSTALLATIONS”

* A – added statement
* A.1 & A.2 Revised
* B.2 & B.4 Revised, B.4 2nd bullet removed, both remaining bullets revised
* B.6 Removed
* VIII. Revised battery backup requirements, backup power source
* IX. Testing, Calibration & Maintenance Stds
* D. Watthour Meters – DC metering requirements

Will continue on VIII next meeting

Appendix B Reference: Omitted from OP18 body. Remains as reference to appendix C.

**March 2014:**

Group finished approval of all sections up to and including V.C. will continue further review at May meeting

**6. Summation: Plans for continuation of discussion & next meeting(s)**

**Action Items:**

* **HVDC metering -** Subcommittee to continue to follow up with HQ on outstanding issues.
* **Station Service Net-Gen –** All TOs to review proposed Appendix D terms and diagrams
  + To note for Chad Nelson to send to meter reader working group
* **Telemetry check proposed pilot** **language**
  + IX.C.1 v3.4 to be reviewed by all TOs
  + TOs to ask their CEII SMEs about data sharing
  + Brock to check w/ ISO on Auditing penalties and/or ties to NERC
* **Transducers and Telemetry:** Accuracy as % of full scale as % of +/- full scale (range) or 0 to +/- full scale. Telemetry SMEs to check with manufacturers
* **OP18 main body reviewed at February meeting for potential approval in April**

**Meeting After:** January 22nd, Webex meeting

April 9th Webex meeting