Massachusetts Technical Standards Review Group (MTSRG)

MTSRG Meeting #1

Date: Mar 6, 2013
Time: 9AM-4PM
Location: E3.961 MOHWAK
National Grid Office: 40 Sylvan Rd, Waltham, MA 02451

Attendance:

Chair: Babak Enayati, National Grid
Vice-Chair: Michael Conway, Borrego Solar Systems
Member (utility): Michael Brigandi, NSTAR
Member (utility): John Bonazoli, Unitil
Member (utility): Erik Morgan, WMECO (alternate)
Member (non-utility): Michael Coddington, NREL
Member (non-utility): Reid Sprite, SourceOne

Utility:
Tim Roughan, National Grid
Bill Walsh, NSTAR
Paul Krell, Unitil
Jennifer Shilling, WMECO

Inverter:
Sonwook Hong, Solectria
John Fearelli, Solectria

Customer:
Gerry Bingham, DOER
Robert Flottemesch, Constellation
William Wohlfarth, Broadway Electrical
Fran Cummings, SEBANE

Via telecon:
Robert Broderick, Abraham Ellis, Sandia Labs
Michael Ropp, NPPT

Agenda

1) The meeting kick off by Babak, review and approval of the MTSRG Guidelines 10 mins

- Guideline not finalized, to be approved for next meeting
- Comments and recommendations from non-members, to use Chair & Vice-chair as a conduit for offering agenda topics for future meetings
- Goal of TSRG: to produce document highlighting commonalities and differences in standards among utilities
- Chair would like to emphasize that utilities have final say on editing common technical manual

2) Status of the company specific interconnection standards 5 mins

- **National Grid** - has published ESB 756 C

- **NSTAR** - goal for a comprehensive standard, 1 year. Will be similar to ESB 765C, incorporating guidelines from other states. In interim, the 14-point checklist is a set of guidelines for interconnecting customers including: protection requirements, onelines, deliverables, witness testing expectations, etc. Mike Brigandi is leading team to develop standard, 6-7 P&C engineers, system planning will also have input. 14-point clarification document is derived from the 12-point version, consolidated for all DG technology types. NSTAR will follow up with document to the group.

- **Unitil** - Has an internal standard of general requirements, close to IEEE 1547 that will become more specific. Covers procedures for requiring DTT, standard service equipment, remote monitoring. Working towards a published standard: no format in mind as of now. Approx timeline: one year.

- **WMECO** - no formal standard. Slides form seminars are posted on WMECO.com/distributedgeneration - working to formalize this into new document. Standards for simplified track to be available by June, followed by expedited. Information requirements, new service guidelines are open for review (internally).

3) DTT and anti-islanding, 9:15 AM-10:15 AM

1. Utility Practices:

   1. National Grid -
      - DG on a feeder section can island with the load (express feeder exempt) beyond a 2sec run on (IEEE 1547). If the existing anti-islanding protection fails to detect the island in a timely manner (2 sec), DTT is required. .
      - Ngrid follows Sandia guidelines for PV projects, DG > 67% min load + reactive power load to generation match.

- If a PV is paralleled with wind (any type but mostly type 3) + wind turbine > 20% of PV rating, a detailed Risk of islanding study must be completed (maximum 40sec run-on times has been seen in one of the studies).
- For rotating generation, DG > 33% of min load, detailed Risk of islanding study must be completed. 3:1 load to generation match. (33% of entire feeder, not at each sectionalizing point)
- DG < 500kW typically doesn't go to Ngrid's Retail Connection Engineering group.
- DTT only used for anti-islanding protection at Ngrid in distribution system. In Transmission system, DTT is used for DCB protection scheme.
- Majority is phone-line DTT, but radio has been installed in some instances. Nuisance tripping has occurred. Trip for loss of communications (2sec time delay). 900 mhz line of sight becomes a challenge.
- Pulse based Power Line Carrier being explored. 6 month trial period, forthcoming pilot project. One pulse transmitter for all generators on the feeder. Transmitter at substation, multiple feeders on bus, transmitter ~ $80k, receiver ~ $5k. Dx3 is vendor. Pulse every 4 cycles (Adjustable). This Once the receiver do not receive the signal, it will be considered as islanding case and the DG will be tripped.

2. NSTAR -
   - DTT based on size, technology type, outcome of system planning portion.
   - No study of abnormal circuit configurations.
   - 1 MW is demarcation for considering DTT.
   - Standard DG recloser at PCC, only trips for under voltage and overcurrent. Feeder outages lead to lock-out. Switching conditions cause a lockout.
   - If there is load behind the meter, but the site is still exporting power, they may want a separate service connections. *(Violates new net-metering rules? Can't have separate load meters, per Tim R)*
   - In one case of large synchronous gen, customer has large communication panel, NSTAR sends passive signal in event that a trip is necessary.
   - Flicker, high voltage, reverse power flow, if any potential issues arise in Impact Study, DTT is considered.
   - Primary trigger for DTT is currently reverse power flow through substation xfmrs.
   - Backfeed policy - not sure of xfmr capability to handle that reverse power. If xfmr vendor can provide a letter confirming that the transformer is capable, it is allowed.
   - In regular system reconfigurations, moving load, DG projects aren't considered or restudied.
   - *MC NOTE: Can NREL or others comment on the % of 10-20-30 MVA substation xfmrs that are incapable of reverse flow?*
   - NSTAR is actively discussing their anti-islanding position, leaning towards Ngrid's anti-islanding standards *(Sandia method)*.
   - How does Ngrid feel about xfmr reverse power flow capabilities? No prohibitions on backfeed, but 3V0 (59N) required on high side for delta substation transformers.

3. WMECO Anti-islanding is looked at as part of Impact Study.
   - Broken up per sectionalizing device.
   - 3:1 load:generation on a circuit segment, requiring DTT scheme. No reactive component considered. No additional risk of islanding study
   - Phone-line is standard DTT medium, fiber and radio have also been explored on a case-by-case basis. 900mhz is terrain (line of site) specific.

- Pilot program for Power Line Carrier. Source frequency for each feeder
- PLC for anti-islanding. Not sure if it's pulse or frequency. (TWAX metering AMI)

4. Unitil
   - Unitil screens for islanding by load:gen ratio
   - PV screen, 50% load:gen match. *(reactive?)*
   - Rotating machines 33% load:gen
   - High speed tripping may be required for substation high side faults. Transmission is delta, no L-G fault detection. No overcurrent protection once transmission relays have cleared.
   - Unitil does examine sectionalizing of line.
   - DTT for fault concerns or anti-islanding concerns.
   - First screen is active load:gen: if that fails, additional system may include reactive component.
   - DTT medium- currently using phone line, but is also exploring Power Line Carrier.
   - Verizon to stop providing anything under T1 landline?
   - Pilot program for cellular-based tripping. (May be included in IEEE 1547.a)

- Why/when is the DTT required? How do utilities identify the islanding scenarios for the below-mentioned types of generators?

- What types of DTT are permitted? Radio? Phone Line, etc?

- Other Alternatives for DTT? Active and Passive anti-islanding?

  PV and discussion on the state-wide adoption of Sandia 2012-1365, revised Nov 2012, Wind, Synchronous Generators, other DG types.

2. Discussion

- Dealing with Telecommunication Companies can be challenging, advantages to avoiding DTT on both utility and DG side.

- Single-phase PV: in the next few weeks, National Grid will post white paper on single-phase, max allowable single phase PV limits
- Addresses lateral fuse sizing, system unbalance
- Babak will send to Gerry to post to DOER TSRG page

4) Limit of 3MVA PV on 13-15 kV feeders and related capacity limits 10:15AM-11AM

1. Utility Practices:

   1. National Grid
      - 3MW limit is National Grid-specific

- Flicker study. Study with GE, modeled with PV and other generation. Cloud transients impact of feeder voltage. Substation regulator operating 27x per day in one instance.
- Unless a voltage regulating technology is installed at the PCC, the max feeder PV is 3MW.
- Estimated number dictated by average feeder loading.
- *M. Coddington- any other solutions mind, for installing a 4MW system perhaps, can they regulate at the PCC?*
- National Grid is actively looking at VAR control, inverter capabilities to import or export VARs.
- Potential hurdle: VAR control desensitizes anti-islanding detection, also effects anti-islanding screening tool. Also effects under/over voltage ride-through because the voltage is being affected by the VAR control.
- Per existing IEEE 1547, the DR shall not actively regulate voltage at the PCC.
- Min loading (in absence of SCADA) = 25% of peak

2.NSTAR -

- No hard limit
- Bill Bush, NSTAR - line drop compensation - control technique is dependent on current flow, not the voltage at the regulator, changes by load conditions, not system voltage
- LTC's at each substation xfmr
- No threshold value, no ceiling. Steady state, no long term dynamics.
- Active VAR compensation, being allowed in one instance, but DTT scheme is in place there as well. STATCOMs (freetown express feeder cluster projects, will not be allowed going forward)
- Min load = 25% of peak

3.WMECO -

- No hard limit
- Impact Study dictates limits on a project by project basis.
- Red flagging for projects with min load to generation mismatch. Condition is brought to the developer's attention in the application/initial screening process
- Min load = 30% of peak

4.Unitil

- No hard limit -
- No dynamic modeling, steady state, static modeling.
- Min load = 30% of peak

- Discussion on the flicker impact and excessive feeder voltage regulator operation due to PV>3MVA.

- Discuss which utilities are utilizing Long-Term Dynamics modeling (12-hr irradiance model) in place of steady-state, binary analysis?

- Total DG limit on distribution feeders (All voltage classes). What are the limiting factors?

- VAR control might be able to eliminate the 3MW PV requirement.

1. Discussion

- Distance from substation is a critical component of DG penetration, but it is difficult to capture that within guidelines and standards.
- IEEE compliance is a voluntary standard, deviations can be mutually agreed upon between utility and customer (active var compensation)
- 10am - 4pm min load is used for PV
- National Grid is using Cyme Long-term Dynamic Modeling through their outside contractors.

5) 15 mins break

6) RTUs - Change to Remote Monitoring and Control 11:15AM-12:15PM

1. Utility Practices

1. National Grid -
   - RTU required for all gen's > 1MW.
   - Monitoring: totalized active and reactive generator export, voltage, current.
   - Status: customer breaker status (monitoring)
   - Control: if customer has local load, National Grid has remote control on generator breaker.
   - If there is no local load (IPP), National Grid will control via the PCC interrupting device.
   - Local load needs to be restored after feeder switching, but generator breaker still needs to be locked out.
   - Improves reliability (SAIDI, CAIDI).
   - Only supervisory control required of the customer.
   - Medium: MPLS line between RTU at customer site, and National Grid RTU at substation.
   - Alternatives: any device (reliable vendor) that meets DNP3 requirements and can communicate with RTU at substation. Example: SEL has a relay than has the monitoring features and meets the DNP3 protocol requirements.
   - Solely used for monitoring and control, not OC protection. National Grid standard: no device can be used for both monitoring and protection
   - Total kva, kvar, kw for site, not specific to generators within site.
   - ***Ngrid dispatch department and smart grid engineers to comment on usefulness of RTU data.***

2. NSTAR -
   - Implement DG standard recloser, SCADA capable, remote monitoring, utilizes MDS radio.

- Safety transfer trip: instantaneous trip, induction machines (recloser closing into an unsynched generator) - vs
- Non-safety: high voltage, flicker - uses radio.
- Have considered fiber signal to customer receiver (outlined above)
- PDR2000 - Iniven (vendor) - communication panel, high speed tripping on transmission lines.
- Net power at PCC, may not be accurate representation of generator output.
- Require recloser at 1 MW and greater.

3. WMECO -
   - No RTU.
   - Recloser at PCC with DSCADA.
   - Dispatch can remotely open the recloser.
   - Unsure of what datapoints are being monitored. ***WMECO to follow-up.***

4. Unitil -
   - Recloser with SCADA at > 1MW
   - kva, kw, kvar, status of PCC recloser, reported by PCC SCADA recloser.
   - No implementation of supervisory control so far (only (2) projects installed in MW range)
   - SCADA to Unitil-owned reclosers, not installed for the purpose of remote disconnecting the generator
   - Existing project: 3x600kW synchronous, monitoring through plant controller, some data points from breakers and recloser. No 'classical' RTU.
   - IEEE 1547 suggests, DG > 250kVA suggest monitoring provisions, doesn't specify real time. Interval metering, recorded data may be acceptable?
   - Special provisions can be made for on-site generator protection. Unitil will accept customer DNP3 from on site gear.

- Why/when is the RTU required?
- Which I/O points are required?
- Types of communication to the dispatch/control center?
- Other alternatives for RTU?
- DNP3 protocol? Modbus?

2. Discussion

- Use of the data: operational awareness, circuit modeling, system planning. Archived data.

- *(R.Sprite) Real time data not being utilized. Is it really required, can it be interval data?* –National Grid policy, a single device cannot be used for both protection and monitoring

- *(R.Sprite follow-up) For heavy load customers, real time monitoring is useful for load shedding, but is it necessary for every DG to be interconnected?*

6) Lunch 12:15 PM-12:45PM

7) External disconnect switches for small generators 12:45 PM- 1:45 PM

- ***(Most of the discussion not applicable to MW-scale projects, geared more towards very small systems. Current load break/recloser requirements for IPP-style projects were agreed to be outside of the scope of this agenda item.)***

1. Utility Practices:

    1. National Grid
        - Outlined in ESB 756C, section 5.6.
        - DG < 25kW, external disconnects are not required.

    2. NSTAR
        - 10-25kW limit still under discussion. ***Mike B to follow up with status of this whenever it's solid?***
        - Every project outside of simplified requires accessible external disconnect switch.
        - Three-phase installations require a lockable load break switch, air break. Line crews can't test dead with recloser. To de-energize a section, an airbreak switch is required. For dead-line work, a recloser cannot be tagged. Contacts under oil are not a visible break (NESC requirement). *(comment directed at larger projects, MW scale)*

    3. WMECO
        - DG < 10kW, external disconnects not required

    4. Unitil
        - DG < 10kW, external disconnects not required. Pulling the meter is a sufficient disconnect at this level.
        - A visible break inside a padmount switch may be sufficient for Unitil. *(comment geared towards larger projects, MW scale)*

    - Why/when are the disconnect switches required?
    - Location of the Disconnect Switches?
    - National Electrical Code (NEC)
    - What are the alternatives, if any?

2. Discussion

    - *(M.Coddington): When disconnect switch is required, can we limit redundancy? Is there a size range where external disconnect isn't required? External disconnect not useful for very small systems (single phase), becomes an additional point of failure.* ***Michael to follow-up with his paper on external disconnects***

    - MA standard is 10kW right now, per tariff. Each utility can interpret accordingly.
    - Special cases: underground area where meter is indoors, external disconnect is required for access reasons

- "easily accessible by the utility" is key tariff term.
- Town ordinances or AHJ may require external disconnects per local fire department request or other.

7) Witness testing protocols 1:45PM-2:45PM

1. Utility Practices:

   1. National Grid -
      - Witness external relay operation. Redundant protection for DG >500kW.
      - Below that, internal protection will be used, and it will not be witness tested. UL listing is valid.
      - Any customer relays are tested, all relay elements 81o/u, 27, 59, 59N, 50/51C and etc.
      - An approved 3rd party will conduct the test, a PTO technician from National Grid will attend and supervise the witness test.
      - Required documentation:
        - Witness test procedure, to outline how the test will be conducted, test equipment, setpoints, etc
        - Energization plan, to be kept on record with the DG group
        - Relay setpoints according to IEEE 1547, underfrequency ride through (NPCC A.03 curve)
      - National Grid offers sample test procedure and witness test guideline on their DG website.
      - Test gets scheduled 2 weeks out? Specified by tariff.
      - Every 6 years, a licensed electrician must test the system, but is commissioned by customer. How will oversight be provided for this? Very difficult for the utility to manage all of the systems online.
      - Upon failure, customer technician will have to troubleshoot the issue (10% error window for setpoints). Second witness test can be scheduled to address only the functions that failed. If the relay is replaced, all functions need to be re-tested.

   2. NSTAR -
      - Similar to Ngrid as far as test procedure.
      - DG > 200kW requires witness test
      - DG < 200kW, customer must submit pictures of installation and documentation of UL listing, applicable codes.
      - Redundant relaying and testing required for:
        - PV > 1 MW
        - synchoronous> 500kW,
        - all asynchronous.
      - For installations without external relaying, not sure how inverter witness test goes.
      - Required documentation:
        - One line,
        - Three-line
        - Relay elementary, logic and tripping diagram,
        - 14-pt checklist signed, stamped.

- Coordination studies and relay settings for approval.
- 81u ride-through settings to include adjustment for NPCC A.03 curve
- Upon failure: identify cause, reschedule and address failed functions only.

3. WMECO -
   - Simplified track: witness test for a handful of projects, battery back-up systems.
   - DG < 30kW, witness test confirms that the system is installed per application, check 2 sec trip and 5 minute reconnect. Modified NPCC curve is required
   - For DG > 30kW underfrequency ride-through setpoint must be modified to 57 Hz.
   - Required documentation
     - Printout of inverter settings
     - Certified test results for customer redundant relay
     - Three-line
     - Relay schematic
     - Review by protection and test group prior to witness test.
   - Slides posted from seminars on DG website, some of this info is included.
   - Upon failure, identify cause, reschedule and address failed functions.

4. Unitil -
   - Simplified track, witness test while meter is being changed out to bidirectional.
   - Quick de-energize and trip.
   - Required documentation:
     - Witness test procedure for approval.
     - Relay and protection requirements and/or IEEE 1547.
   - Upon failure, identify cause, reschedule and address failed functions.
   - Error tolerance: no more strict that internal Unitil requirements for accuracy.
   - 5 year frequency of testing (relaying guidelines).

- Witness test processes and the actions if the test fails.
- What shall be tested?
- Who is qualified to do the test?
- Required documentation (i.e. test procedure, three lines, test reports)
- Possible exemptions for generators below a designated size
- Frequency of testing and reporting

2. Discussion

- UL 1741 allows inverter to be certified post-adjustment of o/u voltage ride-through, etc.
- IEEE 1547.a - 27,59 suggested ride-through settings will be amended

8) 15 mins break

9) Interconnection practices in other states 3PM-4PM

- California Rule 21
  - 100% min load for expedited track - **100% min loading is per feeder section**
- FERC SGIP

- upcoming workshop for SGIP 3/27/13, screening criteria (100% min loading was discussed, is it feeder section or entire feeder load)

- IEEE 1547
- Other company specific standards in other states?

10) Prioritization of issues and scheduling the next meeting

- Networks, interconnection of PV installations 1/15
- "significant change" definition
  - Pending 1547.a, pf schedules, can utilities retroactively ask an existing generator to operate at a power factor different than the nominal to accommodate new projects or system changes? Legal challenges related to the ISA.

IEEE 1547.a updates

- Working group to address 3 items: VAR control, u/o voltage and frequency ride-through requirements.
- Active VAR control, mutual agreement between utility & DR owner in order to implement. VAR injection or import must be managed between DR's on the system.
- Open for comments.
- Frequency roll-off / power reduction
  - Inverter senses f = 60.2 - 61.5 Hz and curtails the output power.
  - Rate of change to reduce power to be agreed upon by utility and DR owner.

- *Soonwook Hong (Solectra Renewables) - difficult to simulate over-frequency grid conditions in lab, power curtailment requires larger generation.*
  - *NREL Energy System Integration lab is a user facility for manufacturers, utilities, etc. DOE owned. Several megawatt testing.*

- DER enterprise integration group - ***Michael Coddington or Babak to send out link***
  - EPRI; how do the utilities take advantage of inverter technologies

- **Interface transformer configuration**
- **Threshold sizes for PCC recloser requirement (vs fused cutouts) - covered 3/6, strike from Sept agenda**
- **Customer relaying redundancy (independent of inverter)**
- **Reverse power flow provisions/requirements (3V0 and N-1 screening) - covered 3/6, but not in great detail**
- **Power factor requirements (utilizing inverter pf for EPS VAR control) - covered 3/6**
- **Cluster study procedure (defining 'electrically interdependent') - to be defined per utility**
- **Networks, interconnection of PV installations 1/15**
- **"significant change" definition**
- **Pending 1547.a, pf schedules, can utility's retroactively ask a project to operate at a PF other than the nominal to accommodate new projects or system changes**

Other utility requirements triggered by DG interconnections
Any other thoughts?

- **Total Clearing Time (relaying requirements)**
  - .16sec and 10 cycle requirements (voltage/frequency) is total clearing time, relay response + tripping
  - *(MC NOTE): Utility parties came to a consensus on this at the meeting, but WMECO (NU protection) has asked that 3-cycle tripping times be removed from the relaying tables on past projects.*

Adjourn 4PM