

Attachment H Comments 7-6-05

ComEd

Joe,

Attached below are the comments that ComEd would like to submit. It is the opinion of ComEd's leadership in the Protection and Control group that ComEd continues to take exception to the connection of DG's to any network, spot or grid, as indicated in Bob Peterson's comments.

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1. At the conference call on 5/24 (missed the 6/20 call SRP Drill) there was much discussion over voltages and connecting customers. I think it should be stated that the TO (Transmission Provider per PJM Tariff for jurisdictional interconnections. JMB 7/5) reserves the right to determine the primary voltage to which the customer gens will be connected. For existing customers this would probably be the service primary voltage but not always.

This topic is procedure, not Technical Requirements, and is covered in the PJM Tariff. JMB 7/5

2. On the picture on page 4 the "IEEE1547" text is shown on the TO side of the drawing. IT should be on the DR side to emphasize that 1547 only covers the customer side. Perhaps under the "DG (Distributed Generator)" text. The note can be added to the one line, remember the purpose of the one line is only for the cross reference of terms from IEEE 1547 vs PJM Tariff. JMB 7/5

3. I don't recall that ComEd has taken no exception to connecting DR to Spot Networks. The notes used to say only when required by State law. This would still be our position until 1547.6 is issued. While I know 1547.6 covers grids, spots and grids are very similar. OK. JMB 7/5

4. Application note 1 talks about connecting PT's to the high side. This should be PT's on all phases or 3VO sensing. This should be in addition to PT's on the secondary side of the transformer, not instead of.

A 27/59 or 3E₀ scheme may not be required in all instances (e.g. when a 51G can be applied for ground faults). Figure 6A shows the requirement for 3 PTs for a delta primary on the main transformer. JMB 7/5

5. Application note 6 states will be determined by PJM Feasibility study. This only applies to DG they are involved with but I would think it should also list the TO as TO/PJM. **OK, JMB 7/5.**

6. On the pictures, they don't show any overcurrent protection or impedance relay protection. For larger co-gens 51 and/or 21 should be shown. Also with larger co-gen breaker failure needs to be included 50BF.
Let's discuss at our next meeting. JMB 7/5.

7. On Fig 6B it states (Network). This should state Primary Network.
It was changed to HV Network to match Figure 6A. JMB 7/5.

8. Appl Note 7 Voltage sensing on TO side. Should state Voltage sensing on the TO side in addition to the DG side of TR. **Let's discuss the requirement for two locations at our next meeting. JMB 7/5.**

9. Appl note 10. ComEd generally does not allow item "d". ComEd requires "a" for net exporters greater than 50% of the minimum line load. **Can d apply for "Behind the Meter" installations ? JMB 7/5.**

10. Application note 11. I could agree with this for ComEd. **OK, we will discuss at the next meeting. JMB 7/5.**

UGI

From: Eric Sorber [mailto:ESorber@ugi.com]
Sent: Friday, July 01, 2005 3:34 PM
To: BURDIS@pjm.com
Subject: UGI Monitoring Requirement

Joe,

I will not be able to make the meeting on the 8th but I did want to get back to you regarding the monitoring issue. Based on discussions with our SCADA and Operations personnel we would like Application Note 4 to read:

UGI requires real-time telemetry for interconnections of 2.0 MW or greater. OK JMB 7/5

Thanks
Eric Sorber
UGI

Chris Cook

From: Chris Cook [<mailto:chris@sunedison.com>]
Sent: Tuesday, June 28, 2005 11:43 AM
To: kerecj@pjm.com
Subject: Re: Next SGIWG meeting will be on July 8th

Joe,

I'm on vacation that week so will be unable to attend. However, I would like to put on the agenda consideration of a secondary network interconnection std. (there are 4 states w/ stds. but no consistency among them) as well as a simplified set of procedural screens for up to 10MW non-export (unless you think this is best addressed at MADRI -- what's being called Level 3a there).

Lastly, will the SGIWG consider the procedural screens in the FERC rule? I suspect FERC may reject a interconnection filing that does not include the screening process in their final rule.

Chris
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PPL

From: Bassett, David L [<mailto:dlbassett@pplweb.com>]
Sent: Tuesday, July 05, 2005 12:56 PM
To: BURDIS@pjm.com; kerecj@pjmexch01.pjm.com; bwjohnson@acninc.net; seeearly@aep.com; james.calore@pseg.com; bremmel@gpu.com; anthony.iannacone@peco-energy.com; mike.mayer@conectiv.com; terry_fix@dom.com; ffrank@alleghenypower.com; james.mcnulty@exeloncorp.com; ccook@e3energy.com; esorber@ugi.com; mksachdeva@aep.com; ken_fugett@dom.com; vladimir.f.basch@bge.com; chuck.thompson@conectiv.com; JNWollete@PEPCO.COM; rladroga@doble.com; kerecj@pjm.com; thomas_basso@nrel.gov; edw_gray@nema.org; jdaley@asco.com; kensmallassoc@comcast.net; earl.moore@exeloncorp.com

Subject: RE: PJM SGIWG draft ATTACHMENT H update to include connections to 10 MW [20 ?]

Fellow SGIWG members:

Below are PPL EU comments on the latest version of attachment H.

1. This document **must be limited to 10 MVA**. Since the IEEE 1547 is limited to 10 MVA, and to maintain agreement with this document and avoid the confusion of units in the 10 to 20 MVA range. Also, the MADRI process has decided to limit their rules to 10 MVA. **FERC definition for small generator and Rule 2006 both state 20 MW. It is the next logical step in our process. JMB 7/5**
2. Starting on page 5 ALL of the IEEE requirements are shown as no exceptions or additions. There are clarifying application notes for several of these. It is not clear **how binding these application notes will be. If Applicable. JMB 7/5**
3. Page 12, **Figure 6a, specifically calls out the metering as 'customer owned'**, I believe this is still optional, and the metering may be owned by either the EPS or the customer. **It is optional and Fig 6A was changed. JMB 7/5**
4. Page 13, **figure 6B, this figure needs to have the DTT added for completeness.** This was mentioned at the last meeting, but missed on the update. NOTE: the metering does not indicate who owns it, which is correct. **Remember, Fig 6B is only typical not specific. DTT is not applicable in all cases and for all companies. I can add DTT and originally was going to except the Figure got too cluttered. JMB 7/5.**
5. Page 10, under the **PPL EU SCADA [section 4.1.6] requirements**, please add the following: **OK. JMB 7/5**

PPL EU will require full time dedicated SCADA communications for installations of 2.5 MW or larger. In these cases, PPL EU will supply design details for a suitable SCADA to be supplied by the customer. Please note, due to protocol restrictions of existing legacy systems, the supplied PPL EU design must be followed.

This system will monitor the real time voltage, MW, Mvar, current and frequency at the PCC (point of common coupling). It will also monitor the status of equipment that is either directly connected to the PPL EU system, or equipment the effects the operation of the PPL EU system. Typically this will include (but not limited to): relay health alarms, DC system alarms, SF-6 gas alarms, DTT communication alarms. The SCADA will also monitor the KWH into and out of this facility on an hourly basis. The system will have control (tripping only) of at least one circuit breaker between the generation and the PPL EU system. Further, PPL EU offers a "unit shutdown" signal for a more controlled trip of the generation facilities in the event of a system emergency. Since each facility is unique, PPL EU will tailor the specific SCADA requirements to the operation of the facility as well as to the specific configuration of the facility.

6. Under Application notes, 4.1.1, PPL EU requests the ability to have all generation facilities be capable of providing or absorbing MVAR and/or following a specific MW/Mvar or voltage schedule to limit impact to the PPL EU system. That is already acceptable per IEEE 1547 if mutually agreeable to Interconnection Customer and TO, or if required in order to maintain voltage regulation as stated in 4.1.1 JMB 7/5

7. Under application notes, 4.1.2, PPL EU agreed to allow the use of delta high side transformers provided suitable ground fault protection is provided. Specific protection requirements will be on a case by case basis, depending on the impact and location of the proposed facility. With the exception of the Attachment H (page 2) General Note addressing 69 kV, adequate ground fault protection (within specified sensitivity and speed) is required by 4.2.1 "Area EPS Faults". JMB 7/5.

8. Add DTT to figure 6B. See answer to 4 which is the same question. JMB 7/5.

General comments:

1. The references to metering need to be consistent on all of the drawings. Ownership should not be stated anywhere, as it is optional. OK, JMB 7/5

2. Without going into the gory details, the statement on page 12, figure 6A about metering 2 of 3 locations is not correct. A statement to replace this should state "The Generation customer should contact the EPS regarding suitable location and application of revenue metering devices." Having load, generation and a common POI there are only two of three values that need to be measured (metered). The third value can be calculated from addition or subtraction of the other two values. JMB 7/5.

3. All three drawings (page 4, and figures 6A and 6B) show a ground on the low side of the transformer, this should be removed. The ground is not required in this location. The probability that it will be delta - wye grounded (as shown) is as likely as any other possibility – It is only a typical one line not a required arrangement. JMB 7/5

Respectively submitted,

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PSE&G

For what its worth, PSE&G agrees with all of PPL's comments, and has a similar approach to SCADA installations above 2.5 MW also.

Jim Calore

FE

Joe/Joe

Attached are FE comments in Blue. We may want to add our endorsement to AEP's comment re: HV disconnect switch.

General Application Note for Transmission¹ System Interconnections

Add after proposed text “Requests for interconnection to other than a radial distribution line will likely require a study to determine the impact of the DR on the particular line.”

Not Applicable. Comment pertains to procedure not Technical Requirements. Procedure is covered by the PJM Tariff. JMB 7/6.

1. Section 4.1.1 - Voltage regulation - For facilities connected to other than FE's radial distribution system, FE reserves the right to require the facility provide or absorb

reactive power and/or follow a voltage schedule. That is already acceptable per IEEE 1547 if mutually agreeable to Interconnection Customer and TO, or if required in order to maintain voltage regulation as stated in 4.1.1 JMB 7/6

2. Section 4.1.2 - Integration with Area EPS grounding - (PPL and UGI dropped their requirement based on the same general Application Note below where the voltage ground detection scheme must be installed on the EPS side of the transformer) AP requires a wye-grounded connection on the T.O. side of the DG step up transformer for all new installations only. This does not apply if a generator is being connected to a system on the low voltage side of an existing Interconnection Customer transformer. Other Transmission Owners within PJM will accept a delta or ungrounded wye connection provided that adequate protection is provided by the DG to detect a ground and limit any overvoltage to an acceptable level on the T.O system. Specific protection requirements will be determined on a case by case basis and will depend on the generation facility's location and system configuration. This protection may requires voltage monitoring on the high side of the DG transformer using phase to ground connected PTs. Also see Note⁵ for an AEP additional Application Note for grounding coordination related to operation of isolating devices.

Application Note 2 may go away if AP drops their requirement for new transformers to be grounded wye on the T.O. side. Some of the FE proposed language addition is not needed because it is just restating the obvious that is listed elsewhere. The addition of the word "may" to the next to last sentence is appropriate. JMB 7/6

5. **Section 4.1.6 Monitoring Provisions** - "Each DR unit of 250 kVA or more or DR aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection". Local monitoring provisions, such as panel meters and indicating lights, may be acceptable to meet Section 4.1.6 requirements in certain cases. In accordance with the provisions of this section, please refer to the following for specific interconnection requirements based on Transmission Owner Zone:

The FE comment (1st sentence) should be discussed at our next meeting to confirm applicability for all T.O.s. Edits to the second and third sentences are improvements. JMB 7/6

First Energy – Depending line parameters, for larger facilities, FE may require SCADA monitoring for generation connected to radial distribution circuits.

For facilities connected to other than a radial distribution circuit, regardless of size, a full SCADA RTU is required. The RTU shall:

- Provide FE with control of all circuit interrupting devices that are directly in the FE transmission path.
- Provide FE with position indication of all transmission voltage circuit interrupting devices and motor operated disconnect devices.
- Provide FE with alarms for each circuit interrupting device and protective relaying in the transmission path (including protection that operates a circuit interruption device in the transmission path).
- For operational purposes, provide FE with instantaneous bi-directional real and reactive power metering (voltage, MW, MVAR) for each line in the transmission path. Amperes are required for each transmission breaker in the transmission path. Relay accuracy instrument transformers and meters/transducers may be used.
- Provide FE access to the revenue metering quantities specified in and in compliance with Section 12 of the FE Connection Requirements using DNP 3.0 communications protocol.

7. Section 4.2.1 - Area EPS Faults - Area EPS Fault Protection requirement for typical interconnection: (Figures 6A and 6B on the following pages are intended to be representative of typical connections to radial and networked lines, specific requirements will be determined during PJM/EDC-ITO Feasibility and Impact Studies on a case by case basis.)

Per the PJM Tariff, the Transmission Provider has authority over the studies. JMB 7/6.

Figure 6A - One Line Diagram for a Typical Interconnection to a radial distribution system.

Typical Protective Relaying Functional Requirements

- 27 - Undervoltage (3 phases, 1 phase if 50/51G can be applied)
- 59 - Overvoltage (3 phases, 1 phase if 50/51G can be applied)
- 81O - Overfrequency (1 phase required)
- 81U - Underfrequency (1 phase required)
- 25 - Synchronizing check (1 phase required)
- 32* - Power * (If required, 1 or 3 phase depending on type)
- 50/51** - Phase instantaneous and time overcurrent (3 phases if required), or
- 21** - Phase distance relay (3 phases if required)
- 50/51G*** - Ground instantaneous and time overcurrent (1 if applicable)

* If required due to reverse power limitations

** 50/51 or 21 but not both required

*** Only if transformer / generator connection allows ground fault current contribution to EPS ground fault

Additional Protective Relaying Functional Requirements (as required)

Dead line closing control (27 and or 25 function) at EPS source breaker(s), line recloser(s), etc.

Larger facilities may require the installation of additional equipment such as directional relaying at the substation feeding the circuit.

Also see Application Notes 13 and 14 for transfer trip and unbalance functional requirements.

Note: IEEE 1547 is primarily intended to be applicable to interconnection of DR on radial distribution systems (**Section 1.3 Limitations** - “Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard,...”).

From a practical standpoint, this represents an upper limit of 3 to 5 MW on most EDC's distribution circuits, unless constructed for the sole purpose of interconnecting the DR.

Note not applicable for all TOs. Transmission system interconnections already addressed on page 2 Note. JMB 7/6

Figure 6B - One Line Diagram for a Typical Interconnection to a looped (Network) system

Typical and Additional Protective Relaying Functional Requirements

Same as Figure 6A above and other as may be required to be compatible with and coordinate with EPS transmission system¹ protection.

In general, requirements developed to connect 10MVA and smaller generation to looped networked sub-transmission systems will be more involved and diverse than those needed for radial distribution systems. Additional considerations, which may be required, include:

- Protective schemes on looped networks are typically stepped zone distance (some with high-speed pilot).

Note not applicable for all TOs. Transmission system interconnections already addressed on page 2 Note. JMB 7/6