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Notes

Generator Verification SDT — Project 2007-09

May 28, 2009
FERC Office
888 First Street, NE
Washington, DC 20426

1. **Administration**
   a. The following were in attendance:

Bob Snow,	Cynthia Pointer,	Lim Hansen,
Keith O'Neal,	Dave Taylor,	Bob Millard,
Harry Tom,	Chris Young,	Rick Terrill,
Mike Laney,	Laurel Heacock,	Lee Taylor,
Jeff Franks,	Stewart Hansen,	Brendan Kirby,
Craig Quist		

2. **Notes**

- There is an open invitation for drafting teams to attend this standing FERC meeting that occurs the 4th Thursday of every month.
- **PRC-024**
  - Bob Snow — questioned the SAR and title change. He was expecting to see a *performance* discussion. Performance would match nicely with other standards. But now this is a relay setting standard.
  - Rick Terrill — Performance has been a big issue. Both the team and the industry do not see a way to actually achieve a performance standard or to measure compliance. WECC looked at event histories. Florida contracted with an engineering firm to analyze a plant to see if it would ride through or to just quantify when the plant might trip. The answer was that the engineering firm would not stand behind an analysis. Rick looked at large fossil units for an event. The plant tripped on auxiliaries 1 minute into the event. 2 "identical" plants responded to the same event very differently. So, while you would like a performance standard the industry felt it was not practical to implement.
  - Bob Snow — so we have been operating for 100 years and things work reasonably well. In doing that planners are doing studies. The Commission has said that today's mandatory standards have an implicit requirement that units ride through.

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- Craig Quist — discussed that with synchronous units the prime mover rides through but the auxiliaries fail after the initial 4 seconds of the transient and that these are not modeled
- Bob Snow — the current standard in the TPL series all say that the transmission planner will have a valid simulation. The Commission has said that a "valid simulation" means that the simulation matches reality. If units trip the model should show that. You still need to meet the requirement that there is no load shedding etc. The Commission's requirement is clearly a performance standard. There is no direction concerning how. PRC-001 already says that generation and transmission relays must be coordinated for all conditions. So a relay standard is not what I was expecting to see. We do performance standards every day because that is what keeps the system running. How do you operate a system without knowing how it will respond?
- Rick — generators typically trip a minute or later due to auxiliaries. The only thing that takes a generator off itself is a trip of the relays.
- Bob Snow — the planner must do an assessment that is backed with studies. Then they determine if performance is acceptable and if not what mitigation was required. I expected this standard to address minimum performance for the output of the generator. The wind order was based on what existing conventional generators could do today. The logic was that existing units could already do that. So 661a was to put everyone on a level playing field – all generators could do it.
- Rick — What time frame are we talking about asking a generator to ride through?
- Bob Snow — transient all the way to steady state.
- Rick — generators can ride through the transient but not the 2 minute "steady state." The short term low voltage may trip auxiliaries in the plant but the generator will continue for 30 seconds to 2 minutes. Is that a hurdle that we need to survive?
- Bob Snow — If the unit has started to trip during the event then it has tripped, it has not ridden through the event. Those were pretty clear words in the Commission directive that said the planner must accurately model that tripping. That is part of the "valid modeling" and the system must ride through the event. The NERC glossary has a very clear definition of normal clearing. That could be zone 2 clearing for a fault at the far end of the line. The way the standard is written you could never use phase distance relays because you can't assure clearing in 9 cycles. Are you going back to the standard committee requesting a change in direction? Rick - No
- Harry — would the standard meet the expectation of a performance standard if the time was extended out for several minutes?

- Bob Snow — the standard must cover the entire time frame. It could be in one standard (preferred) but could be in several standards. The entire time frame must be covered.
- Rick — are you more concerned with the voltage or frequency for performance?
- Bob Snow — I am very concerned with frequency because I am charged with the $0.5 million Berkley frequency study.
- Rick — to cover frequency you have to get into governors etc.
- Bob Snow — I want the generator to stay on line. I don't care why the generator might trip, from dedicated relay or other reason. I don't want it to trip for any reason if frequency is within the standard requirements.
- Rick — nothing but relays could cause a generator to trip on frequency — I pointed out that some CTs are sensitive to frequency — Bob Snow said it was rate of change of frequency and it is high frequency blowing out the lean flame.
- Rick — Could you supply references for the implicit performance requirement?
- Cynthia Pointer said the implicit generator performance requirement is in paragraph 1787 of Order 693 and applies through the TPL standards
    - UNITED STATES OF AMERICA, FEDERAL ENERGY REGULATORY COMMISSION, 18 CFR Part 40, (Docket No. RM06-16-000; Order No. 693), Mandatory Reliability Standards for the Bulk-Power System, (Issued March 16, 2007)
    - Paragraph 1787. In the NOPR, the Commission identified an implicit assumption in the TPL Reliability Standards that all generators are required to ride through the same types of voltage disturbances and remain in service after the fault is cleared. This implicit assumption should be made explicit. Commenters agree with the proposed requirement for all generators to ride through the same set of Category B and C events as required for wind generators. The Commission understands that NRC has both degraded voltage and loss of voltage requirements. The degraded voltage requirement allows the voltage at the auxiliary power system busses to go below the minimum value for a time frame that is usually much longer than normal fault clearing time.[457] If a specific nuclear power plant has an NRC requirement that would force it to trip off-line if its auxiliary power system voltage was depressed below some minimum voltage, the simulation should include the tripping of the plant in addition to the faulted facilities. In this regard, the Commission agrees that NRC requirements should be used when implementing the Reliability Standards. Using NRC requirements as input will assure that there is consistency between the Reliability Standards and the NRC requirement

[457] 10 CFR 50, Appendix A, GDC17

that the system is accurately modeled. Accordingly, the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. If a generator trips due to low voltage from a single contingency, the initial trip of the faulted element and the resulting trip of the generator would be governed by Category B contingencies and performance criteria.

- Lee — the curve does cover zone 2 normally cleared faults because the voltage is higher but the time is longer.
- Harry — the standard was designed to be technology neutral

- **MOD-026: Verification of Excitation System Dynamic Models**
  - As part of a Grid Operations and Planning project with a goal of validating the ambient monitoring strategy for verifying generator dynamic models, EPRI has developed software that, given captured ambient events, will invoke model parameter fitting algorithms to come up with verified models.
  - Chris — How do you assure the models are sound? Does the peer review process fill this requirement?
  - Lee — yes, there is no calculated metric.
  - FERC — will this result in disputes or differences in how TOPs handle deviations? Is there a dispute resolution process?
  - Bob Millard — from a practical standpoint there is no benefit in being unreasonable. This idea originated from a FERC order to ensure facility rating methodologies are “correct”. The solution implemented is a “peer review” process that has been used in other standards. To help make sure they work people who have a stake are involved in these peer review process. It appears to be working well.
  - Keith — 100kV? Why is it different than 60kV?
  - Lee — Most of the time, the applicability would include units that do impact reliability on the BES. However, industry did give us feedback that there are some exceptions where smaller units do impact stability based limits. And some of these smaller units might be interconnected at below 100 kV. Based on industry comments, the SDT plans to propose additional requirements in the next posting that create a process to include other generators that are beyond the base applicability, Critical Units. Industry also expressed that these rules need to be well defined and rigorous. Current thoughts by the SDT are to allow the TOP to identify units that a) have been identified to be participants in a stability based SOL or b) identify units that are not already within the base applicability ranges,

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but actual excitation system behavior has been observed to be something not expected or c) either a or b.

- FERC response was positive to the aforementioned proposal — we also invited them for additional thoughts regarding the identification of additional critical units.
- Chris — what about units that don't run often (maybe 40 hrs/year) but that are critical for those hours? As long as you are on a technical basis you are on the right track.
- Bob — the objective is to capture the bulk of the units and avoid expending effort where it is not needed. The SOLs provide a basis to include smaller units.
- Lee — the criteria was set for each interconnection to capture 80% of the installed MVA. The 80% was based on looking at load flows, and at least in SERC, another avenue is being pursued to hopefully confirm what was determined by load flow observation. Also, if FERC has any leads for a way to independently confirm, or show the need for adjustments, of these thresholds, it would be appreciated.
- Chris — How do you make sure the right generators get verified first? What about geographic dispersion or other factors? Should the standard assure that there are not holes left in for 10 years?
- Lee — no mechanism yet. But there is no incentive for the generator owners to hurt the system by doing the important units late.
- Rick — the transmission planner can ask for specific units that do not appear to be functioning correctly.
- FERC (multiple) brought up that wind was not included in MOD-026 and the other standards. Right now wind is exempted because it only applies to units above 20 MVA. For wind it would likely be an aggregate requirement, not testing of each turbine.
- Brendan — Wind has not advocated to be exempted from MOD-026 or MOD-027. Wind simply did not fall within the size requirements.
- Cynthia pointed out that the current administration is really encouraging renewable resources such as wind. Chris agreed, and asked the SDT to go back and discuss if the applicability should be modified so that it did also include wind plants (Lee Taylor note – seem to me to imply large wind plants).
- Brendan pointed out that if the applicability is modified, that any requirements for wind should include on site equipment installed to help voltage support (i.e., non-unit sources of dynamic MVars such as SVCs).

- **MOD-027** — Verification of speed load control (governor control) systems. — not posted yet but will be similar to MOD-026

- MOD-026 and MOD-027 need to be implemented together because if staged testing is chosen by the generator owner, the staged testing will likely be done simultaneously to save money (especially if consultants are utilized). FERC agreed with the philosophy.

- **PRC-019, MOD-024, MOD-025**
  - Bob Millard — noted that MOD-024 has been sent to NERC staff to prepare for posting.
  - Felt like the "need" for MOD-024 was verified by industry during the Webinar — though there was some concern expressed that industry did not understand the question. However, it is the very first question asked on the Comment Form for the upcoming first posting.
  - MOD-024 utilizes a new concept which allows the Planners (transmission and resource) to communicate to the Generator Operator the conditions which are needed for their studies. This ensures that the effort is not wasted. Also, a generic diagram that covers a multitude of potential configurations for ease of reporting is offered as a template. However, the template does not have to be used, as long as the information is reported.
  - MOD-025 will follow a lot of the same style of MOD-025 — including allowing verification through performance matching followed by an assessment if max MVar is not reached.
  - MOD-025 will verify 4 points on the D curve, so that the TP can approximate the expected unit MVar capability for all operating conditions.
  - Parts of, or potentially all of PRC-019 will potentially be merged into MOD-025
  - Bob Snow — private discussion of MOD-024 requirement — Bob strongly felt that no other standard does the conversion of unit capability to the peak summer conditions (or any other conditions the planner wants). Bob Snow was not present for Bob Millard's discussion.

Brendan Kirby (with edits from Lee Taylor, Rick Terrill and Harry Tom)