Distributed Wind Evaluation Methodology

Thomas E. McDermott, Ph. D., P. E.
MelTran, Inc.
tom@meltran.com

UWIG Utility Wind Integration Group — Distributed Wind Impacts Project

Abstract - The Utility Wind Integration Group (UWIG) has undertaken a Distributed Wind Impacts project, which has produced software tools, application guides, and case studies to evaluate distributed wind projects. The project size may range from 1.5 to 15 MW, or higher in the near future. Given a number and size of available utility-scale wind turbines, and a candidate site, the evaluation process follows these high-level steps:

1. Capacity factor estimate from wind speed and other site characteristics.
2. Determine financing and power purchase agreement options.
3. Estimate the maximum feeder voltage change from full-on to full-off operation.
4. Electrical island evaluation from load and wind generation profiles; determine the need for transfer trip or other mitigation.
5. Flicker screening from the substation transformer size, type of line conductor, and distance from the substation.
6. Using a more detailed feeder electrical model:
    a. Estimate the loss of sensitivity in detecting ground faults with resistance.
    b. Check for proper coordination of the feeder overcurrent protective devices.
    c. Check for proper operation of utility tap changer and capacitor switching controls.
7. Design the interconnection, including transformer winding connections and wind turbine generator protection settings, to meet IEEE Std. 1547 and regulatory requirements.
8. Post-installation monitoring and evaluation, focusing on energy production and flicker.

The methodology has been applied to several distributed wind projects, and these results are presented as case studies. The method is also presented at an annual workshop co-sponsored by National Renewable Energy Laboratory (NREL), American Public Power Association (APPA), National Rural Electric Cooperative Association (NRECA), and Western Area Power Administration (WAPA).

Introduction

The UWIG Distributed Wind Impacts Project has produced a suite of software tools, available to project members, at http://www.uwig.org/distwind/default.htm [1]. These tools fit into an overall project evaluation framework, shown in Figure 1. First, it's necessary to obtain one or more wind turbines for a small project, which may be challenging in the current market. Then, a **screening** of the site economics and electrical source strength occurs. The economic screening tool is an enhanced version of NREL's WindFinance application. The site electrical screening tool initially focused on flicker, but has recently expanded to consider other screening criteria. For projects that seem attractive after initial screening, the tool set supports more detailed **engineering** analysis of the feeder interconnection, including protection and control issues.

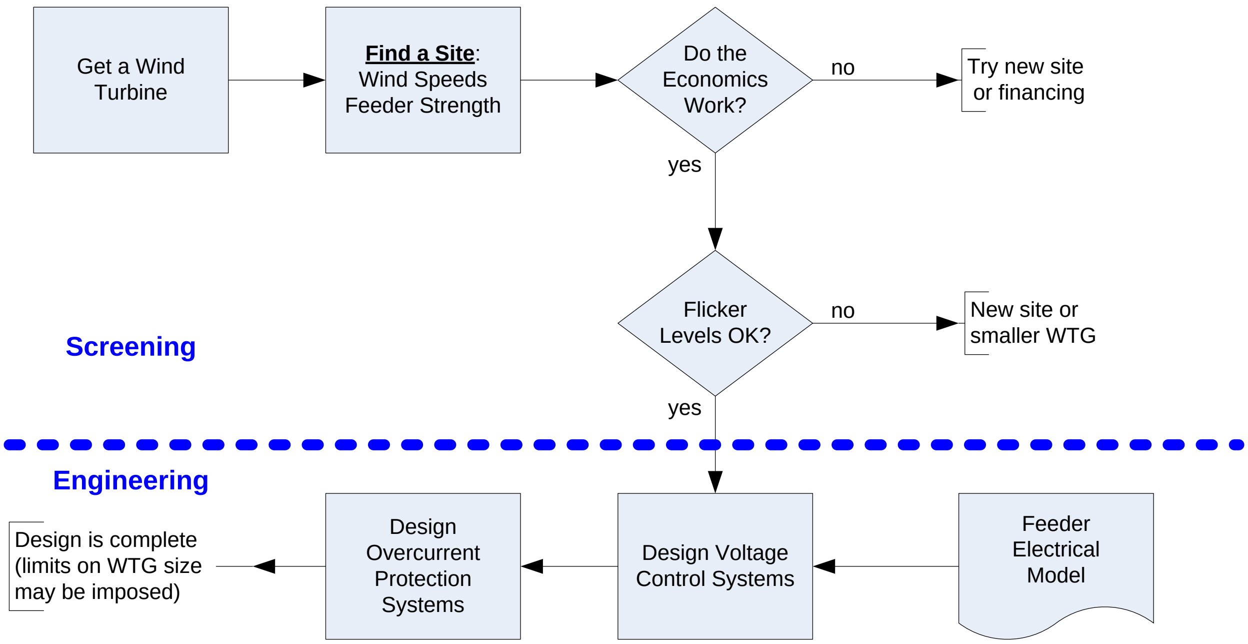


Figure 1 - UWIG Distributed Wind Evaluation Flowchart

In Order 2006, the FERC presented fast-track acceptance criteria for generation projects that may be accepted without detailed study. These criteria provide a useful starting point for project screening. Although not accepted in all jurisdictions, FERC Order 2006 is representative of many state regulatory commission acceptance criteria for distributed generation projects. The criteria are:

- The design is certified, such as by the Underwriters Laboratory (UL). Any modern wind turbine meets this criterion.
- Project size ≤ 2 MW, which would usually limit the project to just one turbine. It's now common to see distributed wind projects planned for 10 MW or more, so they would not meet this criterion.
- Project size ≤ 15% of the feeder segment peak load, which can be difficult to meet. A light load level might be 35% of the peak load, so the generator output would then be only 43% of the light load, which effectively precludes an unintended electrical island. But a 2-MW generator would require a feeder peak load of 13.33 MW to meet this

criterion, which is near the upper limit for a feeder in the 15-kV class. Furthermore, the limit should be met for the smallest switched segment that might be isolated with the wind turbine. If a line recloser can open to isolate just 1/3 of the feeder load with the wind turbine, then the feeder peak load would have to be 40 MW to meet this criterion.

- Project contributes ≤ 10% utility fault current on the primary feeder. This requires knowledge of the feeder source strength at the point of connection, but is generally not difficult to meet.
- All utility devices have ≤ 87.5% fault interrupting rating, after the project has been installed. This requires a more detailed feeder model to evaluate, and previous distributed generation projects may have an impact.

To summarize, most distributed wind projects won't meet the fast-track acceptance criteria in FERC Order 2006, with unintentional electrical islanding being a point of main concern.

The FERC criteria apply to any generation technology. Voltage flicker is a concern specific to wind turbines, and standard planning criteria apply for project acceptance [2, 3].

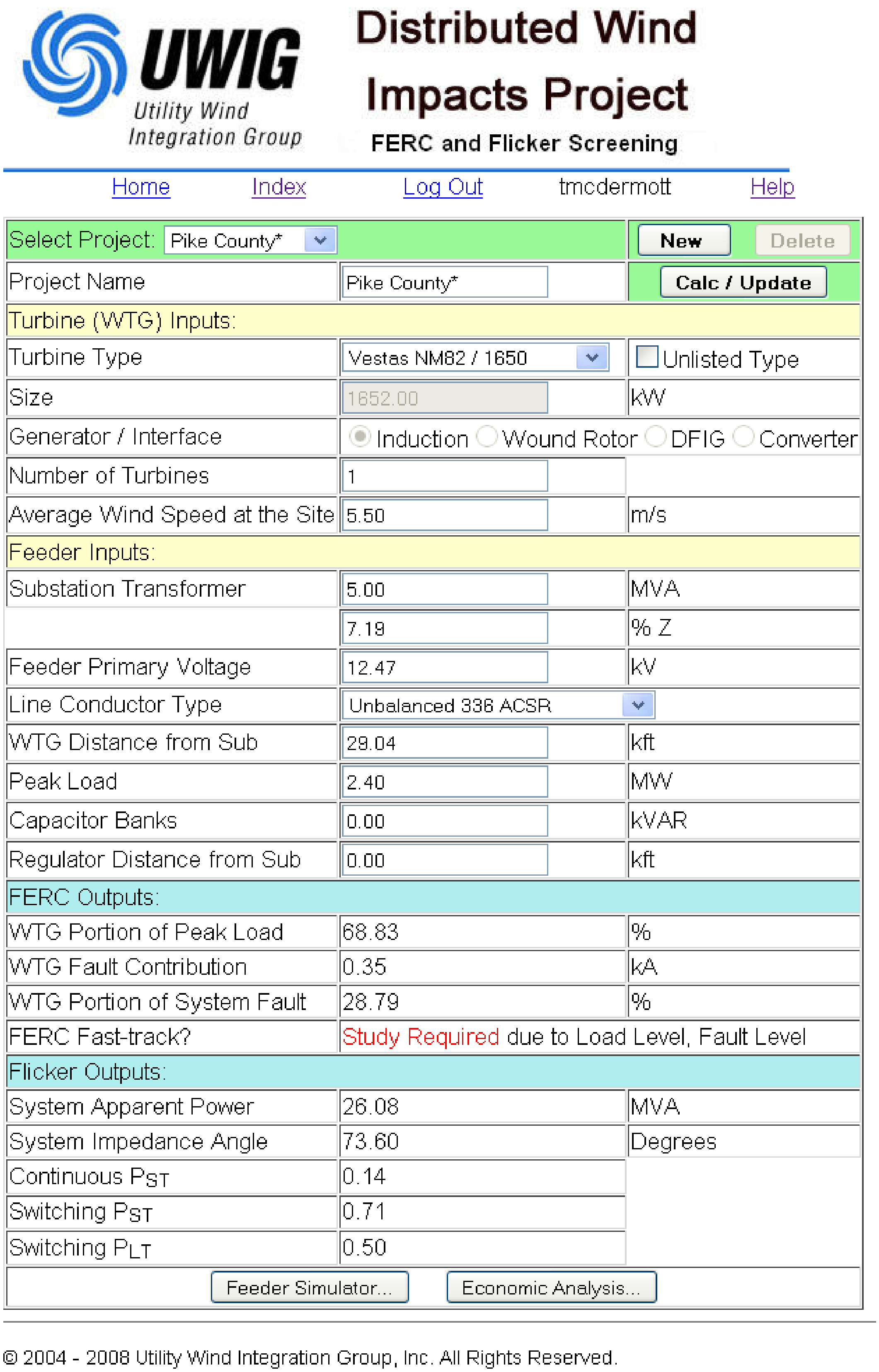
- Continuous short-term flicker level, $P_{ST} \leq 0.9$
- Switching flicker level, short-term $P_{ST} \leq 0.9$ and long-term $P_{LT} \leq 0.7$

These require knowledge of the feeder source strength at the point of connection, along with power quality test reports for the wind turbines. These reports are not available for all turbine types, which can make a flicker evaluation difficult.

Figure 2 shows the recently expanded UWIG screening tool, which evaluates the project against both FERC fast-track and flicker planning level acceptance criteria. The wind turbine inputs (first **yellow** headlined section) consist of the model selection, number of turbines, and site wind speed. The electrical inputs (second **yellow** headlined section) consist of the substation transformer size and impedance, feeder voltage level and conductor type, and the distance from the substation. These provide an estimate of the electrical source strength at the point of connection. Another required input is the peak load level for evaluation. Depending the the feeder switching arrangements, this can be the feeder peak load, or the peak load on just a portion of the feeder. Most of these parameters are readily available to electric utility personnel. (Node: the capacitor and line regulator inputs are needed only to initialize the detailed feeder model for engineering analysis, not for screening evaluation.)

The FERC outputs are shown in the first **blue** headlined section. For this example, the turbine size contributes too much fault current and is too large relative to the feeder peak load, so that a **detailed study is required**. A DFIG or full-converter interface could meet the fault contribution requirement, while either a smaller turbine, or a different feeder with higher peak load, could meet the load level criterion.

The flicker outputs are shown in the second **blue** headlined section, and in this example, all of the planning levels are met. The selected turbine model has a power quality test report in the UWIG library. For turbines without flicker data in the library, UWIG's tool will back-calculate the maximum flicker coefficients (C_F, K_F, N_{120}) to meet the planning levels. The project developer could then check with the turbine vendor to make sure the turbine will achieve the necessary flicker performance.



UWIG Utility Wind Integration Group

Distributed Wind Impacts Project

FERC and Flicker Screening

Home | Index | Log Out | tmcdermott | Help

Select Project: Pike County*		New / Delete
Project Name	Pike County*	Calc / Update
Turbine (WTG) Inputs:		
Turbine Type	Vestas NM82 / 1650	Unlisted Type
Size	1652.00	kW
Generator / Interface	Induction / Wound Rotor / DFIG / Converter	
Number of Turbines	1	
Average Wind Speed at the Site	5.50	m/s
Feeder Inputs:		
Substation Transformer	5.00	MVA
	7.19	% Z
Feeder Primary Voltage	12.47	kV
Line Conductor Type	Unbalanced 336 ACSR	
WTG Distance from Sub	29.04	kft
Peak Load	2.40	MW
Capacitor Banks	0.00	kVAR
Regulator Distance from Sub	0.00	kft
FERC Outputs:		
WTG Portion of Peak Load	68.83	%
WTG Fault Contribution	0.35	kA
WTG Portion of System Fault	28.79	%
FERC Fast-track?	Study Required due to Load Level, Fault Level	
Flicker Outputs:		
System Apparent Power	26.08	MVA
System Impedance Angle	73.60	Degrees
Continuous P_{ST}	0.14	
Switching P_{ST}	0.71	
Switching P_{LT}	0.50	
Feeder Simulator...	Economic Analysis...	

© 2004 - 2008 Utility Wind Integration Group, Inc. All Rights Reserved.

Figure 2 - UWIG Distributed Wind Project Screening Tool

Hull Near-Shore Wind (HNSW) Project

The town of Hull, Massachusetts already has a medium level of distributed wind penetration [4], and is now considering a 12-MW project that would result in a relatively high level of distributed wind [5, 6]. Figure 3 shows the location of an existing 660-kW turbine (Hull Wind 1) and 1.8-MW turbine (Hull Wind 2) serving part of the load in Hull. The proposed project consists of four 3-MW turbines, totaling 12 MW, located a couple miles off shore, hence the designation Hull Near-Shore Wind (HNSW). Due to the high level of wind generation relative to the town load, a screening and engineering analysis was done using a combination of the UWIG tools [7], and an open-source simulation program [8] that has more detailed analysis capability.

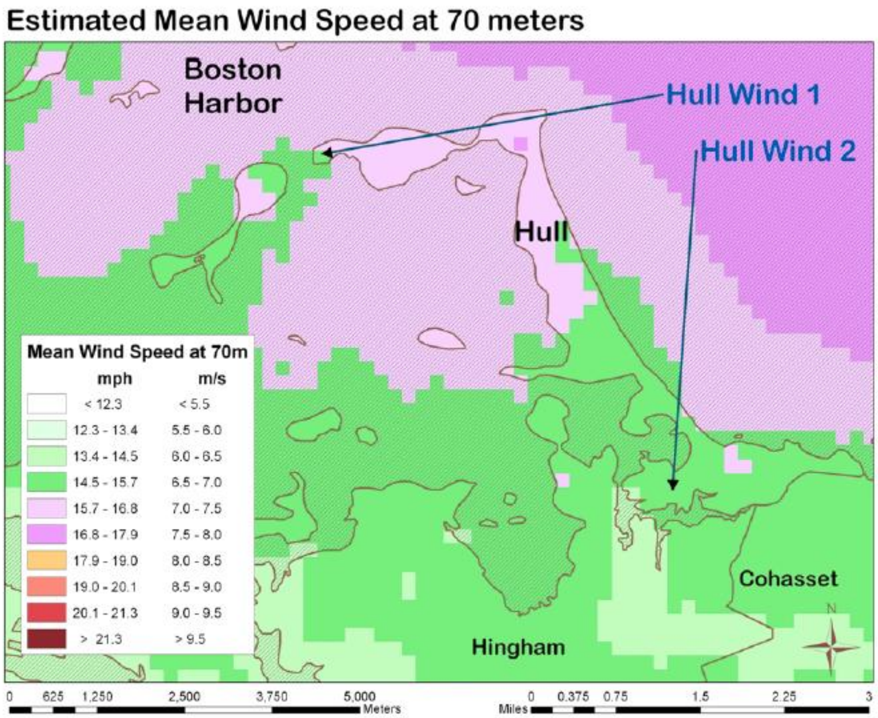


Figure 3 - Wind Resource Map of the Hull Area [4]

Table 1 shows the capacity factor estimates for two existing wind turbines, and two possible models for the new off-shore wind turbines. These estimates come from the UWIG tools. The V90 and GE 3.6 both have lower capacity factor than the existing wind turbines for the same wind speed, but due to higher wind speeds off shore, the actual capacity factors are expected to be comparable. (Note: the GE 2.5 is not an off-shore design. It was included in Table 1 for comparison to the on-shore V80.) These capacity factors are competitive, but the project's economic feasibility still depends on managing the costs of interconnection, including submarine cables. Widespread system upgrades, such as feeder re-conductoring or underground cable replacement, could also make the project unfeasible. The utility is a municipal light plant and should be eligible for Clean Renewable Energy Bonds (CREB), but the project may be too large for CREBs to have a major impact. Some grants may become available from Massachusetts or other sources. The project backers are also exploring some options for turbine availability. It is not yet certain that the project will move forward.

Table 1 - Estimated Capacity Factors for Wind Turbines at Hull

Wind Speed [m/s]	V47 (Hull 1)	V80 (Hull 2)	V90	GE 2.5	GE 3.6
5.5	0.1928	0.2830	0.2372	0.2875	0.2304
6.0	0.2388	0.3364	0.2820	0.3396	0.2759
6.5	0.2851	0.3876	0.3267	0.3899	0.3212
7.0	n/a	n/a	0.3703	0.4373	0.3655
7.5	n/a	n/a	0.4120	0.4813	0.4079
8.0	n/a	n/a	0.4511	0.5217	0.4478

Figure 4 shows a simplified one-line diagram of the Hull Municipal Light Plant (HMLP) electrical system, fed by two relatively small autotransformers that constitute a weak source, with low fault current levels. The loads are served by three radial feeders, each having a line voltage regulator near the “substation”, and each having a seasonally switched 600 kVAR capacitor bank. The “substation” consists of three pole-mounted reclosers, including a normally open tie, and some metering equipment. The newer tapped line 3 has its own recloser (3A) near the substation, while the two longer feeders have downstream line reclosers (1A and 2A).

The connection point preferred initially is near A and K Streets, because space is available for switchgear, and because that point is closest on land to the probable area of wind turbine deployment. However, two underground cable segments limit the ampacity of those two feeders, so that only two turbines could be connected to each feeder. This means the collector cable would have to be operated in an open loop configuration, and possibly two different cables would have to be laid.

By connecting HNSW near Hull 2, served by the larger autotransformer, it may be possible to use just one cable, similar to a radial collector cable in a larger wind plant. The existing Hull Wind 2 turbine would be switched over to weaker the Hull 1 source, to better balance the load and generation. There is plenty of space available here, since the reclosers and Hull Wind 2 are located in the town dump. If the collector cable uses a typical 33-kV voltage level, there would be space for an interface transformer to the 13.8-kV feeders. Space is more limited near A and K Streets. Finally, connecting HNSW near the source would limit its effect on the existing feeder voltage control (regulators, capacitor banks) and overcurrent protection (reclosers, fuses).

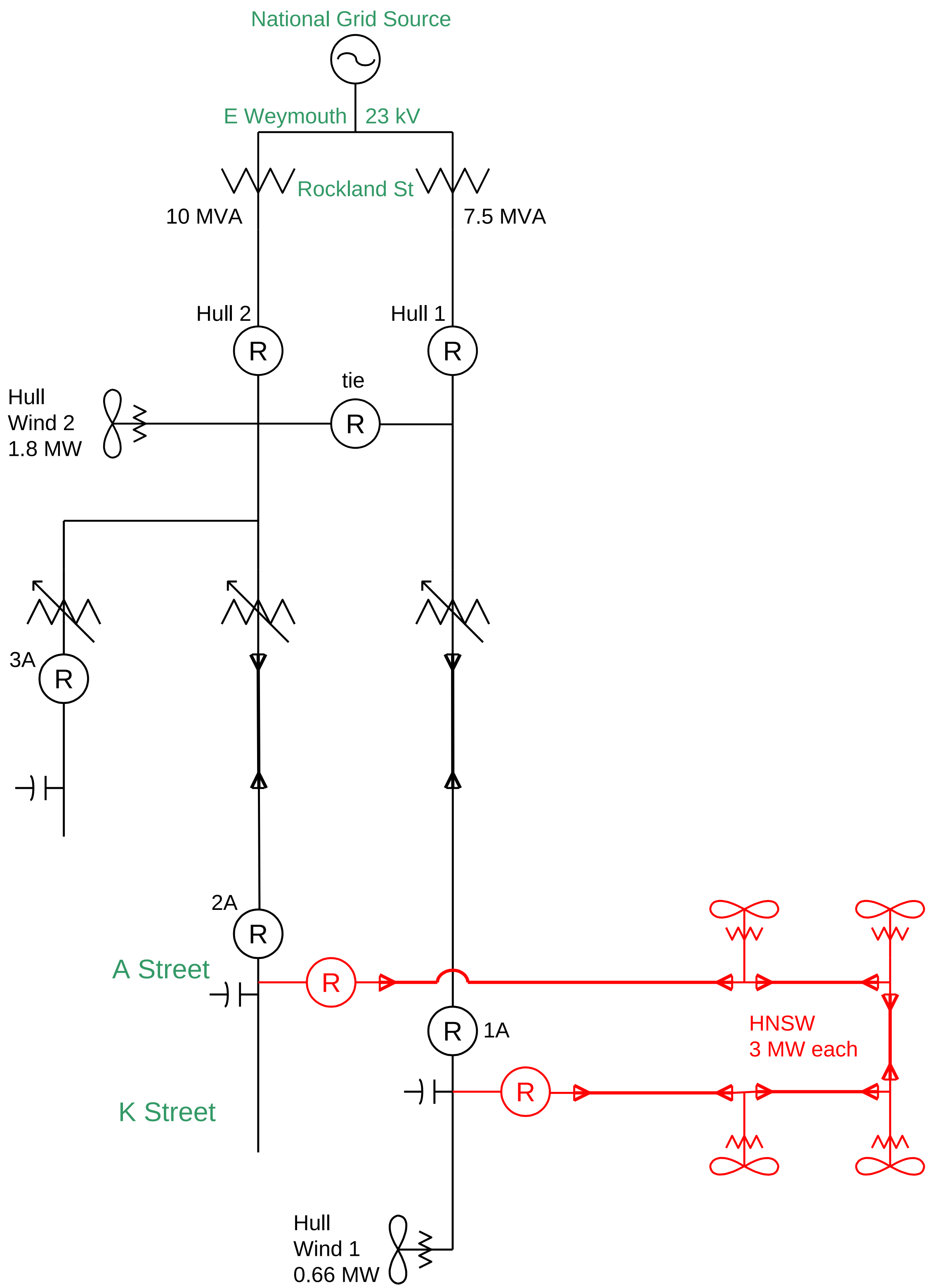


Figure 4 - One-line diagram of the Hull Near-Shore Wind point of connection

Checklist Approach to IEEE 1547

IEEE Std. 1547 is the “Standard for Interconnecting Distributed Resources with Electric Power Systems” [9]. It was initially approved in 2003, and re-affirmed with no changes in 2008. This standard is technically voluntary, but has been referenced in the Federal Energy Policy Act of 2005 and by many state regulatory commissions. Many utility tariffs also specifically reference the standard. It is evident that IEEE Std. 1547 has been applied to the existing Hull wind turbines.

In addition to the main standard, there are currently 6 sub-parts published or under development.

1. Test Procedures (2005)
2. Application Guide (2009) [10]
3. Monitoring and Control (2007)
4. Electrical Islanding
5. Generators > 10 MVA Connected to a Transmission Grid
6. Secondary Networks

One of the limitations is that IEEE Std. 1547 only applies to generation up to 10 MVA in size, at the point of interconnection. There is a gap between this level and the 20-MVA limit on “small generation” defined by FERC and many other agencies. The HNSW project size would fall into this gap, but it’s recommended that IEEE Std. 1547 still be followed to the extent possible.

The following is a brief summary of what IEEE Std. 1547 would require for HNSW wind turbine interconnection.

1. Do not actively regulate voltage.
2. Do not cause any voltages outside ANSI C84 Range A. Basically, this is 114 to 126 volts at the service level, or +/- 5%.
3. Create no damaging overvoltages in the Area Electric Power System.
4. Create no disruption of overcurrent protective device coordination.
5. Deenergize for faults on the connected circuit.
6. Deenergize prior to circuit reclosure.
7. Trip in response to any phase-phase voltage at the point of interconnection:
    a. In 0.16 s for any voltage; $V < 50$ %.
    b. In 2.00 s for any voltage; $50\ \% \leq V < 88$ %.
    c. In 0.16 s for any voltage; $110\ \% < V < 120$ %.
    d. In 1.00 s for any voltage; $120\ \% \leq V$.
    e. These are default tripping times; the standard allows adjustment.
8. Detect and de-energize unintentional islands within 2 seconds. The following are examples of methods to meet this requirement:
    a. DG aggregate is less than 1/3 minimum electric power system load.

   b. Reverse power flow detection at the point of common coupling, for small generators.
   c. Transfer trip.
   d. Forced frequency or voltage shifting.
   e. Constant power or power factor controls.
   f. Certified to pass a non-islanding test.
9. Trip for frequency deviations:
   a. 0.16 s if $f > 60.5$ or $f < 57.0$
   b. Adjustable 0.16 – 300 s if $57.0 \leq f \leq 59.8$
10. Cause no voltage fluctuation > 5%
11. Cause no objectionable voltage flicker per IEEE Std. 1453.
12. Meet the harmonic limits in IEEE Std. 519 [11].
13. Do not energize the electric power system.
14. There must be an accessible, visible, and lockable isolation device.
15. Monitor at least the on/off status, voltage, real power, and reactive power.

The interconnection transformer winding connections play an important role in items 3 and 4. Large central station generators usually have a wye/delta transformer, with a delta winding on the generator side. This usually cannot be allowed on radial distribution feeders because the delta winding provides a ground fault source that usually interferes with existing overcurrent protection settings. Hull Wind 1 uses a delta/wye transformer, with a wye winding on the generator side. This avoids the ground source issue, but it can produce high overvoltages during backfeed conditions. The wind turbine is small enough that this should not present a problem in actual practice. The Hull Wind 2 turbine uses a wye/wye transformer, but this does not provide a ground source nor limit backfeeding overvoltages, because the wind turbine generator itself is not grounded.

Items 7 and 9 define the minimum required protection functions. Most turbine vendors will add overcurrent protection, negative sequence unbalance protection, rotor crowbar functions, and others as appropriate to their products.

Items 1 and 15 are related. Modern turbine designs can provide adjustable reactive power, and hence voltage control. However, this is not to be done with local automatic control at the turbines. Instead, HMLP could dispatch the turbine reactive power from a central location to help manage voltage profiles on the system.

Item 8 merits special attention for a project of this size, because it won't meet criteria 8a or 8b. The only method under HMLP's direct control would be 8c, a transfer trip. The other islanding detection methods, 8d, 8e, and 8f, are advanced functions that a turbine vendor might provide.

Items 5, 6, and 12 are the turbine vendor's responsibility. Items 13 and 14 are HMLP's responsibility through its installation and operating practices. Items 2, 4, 8, 10, and 11 are the subject of more detailed analysis in the next section.

Engineering Analysis

This section addresses voltage control, overcurrent protection, islanding, and flicker concerns listed in the previous section. The UWIG tools can perform these tasks for a single feeder with one main turbine installation, but the HNSW project in Figure 4 is larger and more complicated. Some working group papers provide guidance in performing the necessary analyses [12, 13].

Table 2 shows the steady-state voltage change between full-on and full-off generation as estimated from:

$$V_{drop} = \frac{100}{U_n^2}(R_1 + jX_1)(P_n - jQ_n)$$

$$\frac{dV}{U_n} = \sqrt{(100 + \mathrm{Re}V_{drop})^2 + (\mathrm{Im}V_{drop})^2} - 100 \qquad [\%]$$

Where *R1* and X1 are the system impedance values in ohms, *Pn* and *Qn* are the generator real and reactive power in MVA, *Un* is the system voltage in kV, and *I3* is the three-phase fault current level.

Table 2 - Steady-state Voltage Change from HNSW Connection Options

Case	R1	X1	Pn	Qn	Un	dV[%]	I3 [kA]
K L2P14	2.5079	5.8122	6.00	0.00	13.8	9.44	1.26
K L2P14	2.5079	5.8122	6.00	1.87	13.8	14.72	1.26
K L2P14	2.5079	5.8122	6.00	-1.87	13.8	4.27	1.26
Wind1	3.8459	7.7237	0.66	0.00	13.8	1.37	0.92
Wind2	1.1470	3.1000	1.80	0.00	13.8	1.13	2.41
Wind2 on Hull 1	1.2580	3.4000	1.80	0.00	13.8	1.24	2.20
HNSW on Hull 2	1.1470	3.1000	12.00	-3.75	13.8	3.45	2.41

The voltage change should be no more than 5%. The first three rows of Table 2 show the voltage change for 6 MW connected to either feeder near K and A Streets. It’s necessary to operate at leading power factor of 0.95, with negative Q_n, and the wind turbines absorbing reactive power. With cable segment ampacities of about 250 amperes, it’s not possible to connect 12 MW of wind generation at this location. The next two rows of Table 2 show the voltage changes for existing Wind 1 and Wind 2 turbines are well within 5%, even when operating at unity power factor. That result was expected, because the existing turbines have produced little or no customer complaints related to power quality. The last two rows show that the voltage change from HNSW is acceptable, with all 12 MW connected at the Hull 2 source, if operating at 0.95 leading power factor. The HNSW should not attempt to actively regulate voltage, but on the other hand, the utility can still dispatch the generator reactive power to desired levels, which may vary depending on load and generation conditions.

If HNSW turbines are connected near K and A Streets, the existing feeder capacitor banks should be switched off, and the line voltage regulator control settings may require adjustment.

In a systematic process, three-phase and single-phase faults were applied at several key points in Figure 4. The utility reclosers and fuses still coordinated properly, for both the Hull 2 connection and the K and A Street connections. At several buses, 25-Ω ground faults were not detected, but this was also true without wind generation. The recloser ground trip settings could be made more sensitive to detect resistive ground faults. HNSW should have dedicated reclosers or circuit breakers, no matter where the connection is made. Since reclosing times had already been increased to 2 seconds for the existing wind turbines, no further changes to the overcurrent protection system were necessary for HNSW. But, if transfer tripping is implemented to prevent electrical islands, it would then be possible to reduce the reclosing times below 2 seconds.

Since the HNSW project would add significant cable capacitance to a relatively weak distribution system, frequency scans were performed to identify any potential harmonic resonance problems. No significant harmonic issues were found.

The flicker levels are estimated from:

$$P_{st-c} = C_f(\phi, v)\frac{S_n}{S_k}$$

$$P_{st-k} = 15\sqrt[3.2]{N_{10}}K_f\frac{S_n}{S_k}$$

$$P_{lt-k} = 6.9\sqrt[3.2]{N_{120}}K_f\frac{S_n}{S_k}$$

Where S_k is the system source strength and S_n is the turbine size, both in consistent units of kVA or MVA. The other parameters come from the turbine vendor's power quality test report, and C_f depends partially on the site wind speed, v, and the system impedance angle, ϕ. With more than one turbine, continuous flicker uses RMS or square root weighting, while switching flicker uses 3.2-root weighting:

$$P_c = \sqrt{\sum_i P_{c-i}^2}$$

$$P_k = \sqrt[3.2]{\sum_i P_{k-i}^{3.2}}$$

Both existing wind turbines were estimated to generate flicker within the planning limits, which agrees with the operating experience of no customer complaints. Since the turbine model for HNSW is not yet known, Figure 5 presents the maximum turbine flicker coefficients that meet the planning limits, for 6 MW at K and A Streets, or 12 MW at the Hull 2 source. For a single 3-MW turbine, the maximum C_f is 6.8, the maximum K_f is 0.25, the maximum N_{10} (switching operations in 10 minutes) is 10, and the maximum N_{120} (switching operations in 120 minutes) is 55.

Name	Distance	Angle	S1 [MVA]	I3ph [kA]	Pst-c	Pst-k	Plt-k
Hull2	6.50	69.5	50.96	2.13	0.400	0.453	0.355
L2P14	26.27	65.2	31.91	1.34	0.639	0.724	0.567
		Sn	3	=> 4@Hull2	0.801	0.699	0.548
		C	6.8	=> 2@L2P14	0.904	0.899	0.705
		N10	10				
		N120	55				
		K	0.25				

Figure 5 - Maximum Flicker Coefficients for HNSW Connection Options

To evaluate the risk of electrical islanding, a 2006 load duration curve was used with capacity factor estimates for the existing wind turbines and HNSW. Wind speeds are often represented with a Weibull distribution having a shape factor of 2 (also called a Rayleigh distribution). The cumulative density function, mean, and variance for this distribution are:

$$P[x \le X] = 1 - \exp[-(X/\lambda)^k]$$

$$\mu = \lambda\Gamma(1 + 1/k)$$

$$\sigma^2 = \lambda^2\Gamma(1 + 2/k) - \mu^2$$

It was found that a Weibull distribution also represents the wind power generation reasonably well, with a shape factor, k, of 1.8 and a scale factor, λ, of 1.1245 μ. Figure 6 shows the binned probability density functions for the load, existing Wind 1 generation, Wind 1 + Wind 2 generation, and Wind 1 + Wind 2 + HNSW generation. The system peak load is about 13.5 MW with a load factor of 40%. The wind turbine capacity factors are expected to range from about 27% to about 37%. With just Wind 1, there is a 0.19% probability of generation exceeding the load. Adding Wind 2 raises this probability to 0.69%, which is still a negligible risk. Adding HNSW to the existing wind turbines will produce a 39.72% probability of generation exceeding the load. This indicates a significant risk of unintended electrical islanding if an upstream utility recloser opens. More detailed simulations or tests could verify, disprove, or refine this conclusion, but such studies require significant time, data, and expertise to complete. Instead, high-speed transfer tripping was recommended, and this is easier to implement with a connection at the Hull 2 source point. As an alternative, advanced anti-islanding detection schemes might be specified and tested.

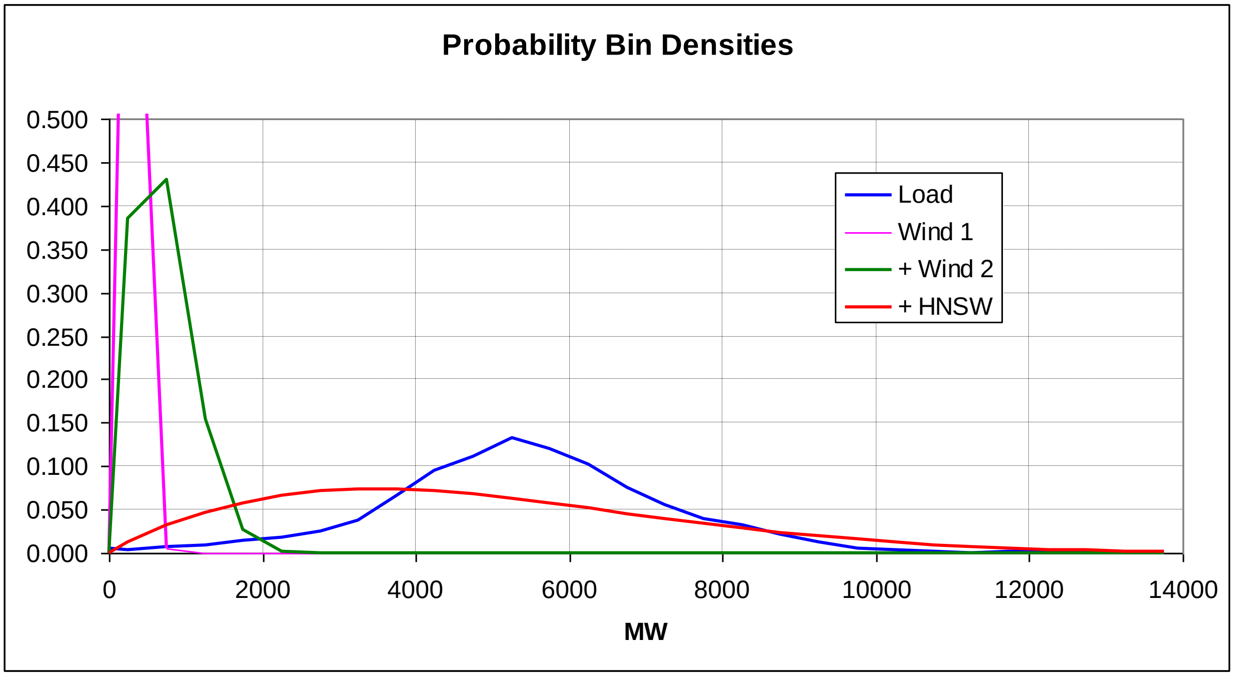


Figure 6 - Probability density of Hull Load and Wind Power

Low-Voltage Ride-Through

Distributed generation must trip under certain overvoltage or undervoltage conditions, according to IEEE Std. 1547. For larger wind plants, low-voltage ride-through (LVRT) requirements are under development, so the question may arise whether these requirements are compatible. An electric power system with significant levels of distributed wind may grow to depend on the wind generation, and may not want the turbines to trip under low voltage conditions. One of the most general proposed LVRT requirements, from FERC, says only that the plant must ride through a 3-phase fault with normal clearing from 4 to 9 cycles, and through the post-fault voltage recovery transient. The terminal voltage could be zero during the 4 to 9 cycles, and the post-fault recovery voltage could, in theory, follow any path, not having to lie within a specified envelope. A similar FERC requirement applies to single-phase faults with delayed fault clearing. An exception occurs if the fault disconnects the plant from the system, in which case the plant and its wind turbines are allowed to trip.

In comparing IEEE 1547 to the various LVRT requirements, it must first be noted that IEEE 1547 only applies to plant sizes of 10 MVA or less, while the LVRT requirements apply to larger plants. It is only when considering a larger aggregate of distributed generation that the possible relationship between these two requirements could be of some technical interest. Since the IEEE 1547 undervoltage tripping times begin at about 10 cycles, there isn't necessarily a conflict with the first portion of FERC's LVRT. It's possible that a subsequent voltage recovery would cause the turbine to trip under IEEE 1547, when it should not trip if the FERC LVRT requirement applied.

There are other LVRT requirements under development, and Figure 7 presents some of them along with the IEEE Std. 1547 undervoltage and overvoltage trip curves. The Western Electricity Coordinating Council (WECC) requirement has undergone several iterations, and at present, defines only two points without an envelope between them. The turbine must ride through possibly zero terminal voltage for up to 9 cycles, and then at 0.8 per-unit recovery voltage, the trip time must be at least 40 cycles. This WECC-2 requirement applies to plants of 20 MVA or larger, connected at 60 kV or higher.

It's possible that NERC will adopt a LVRT requirement, based on proposals from WECC and/or other regional reliability organizations, and that this will become the de facto LVRT standard, at least for North America. On the other hand, Hydro Quebec (HQ) has defined a more stringent LVRT requirement, shown in Figure 7, which is necessary for the Hydro Quebec system conditions. This is just one illustration that LVRT requirements may not settle down to a single standard.

Conclusion

Developers are contemplating ever-larger distributed wind projects, which require more detailed system models and evaluations. The tools are available for these tasks, and in general the projects are technically feasible. The main barrier to distributed wind projects is probably turbine availability. However, with increasing queue congestion they might benefit from consideration as "small" projects of no more than 20 MVA. Even if a project doesn't qualify for fast-track acceptance, according to FERC a small project has less stringent requirements on the interconnection studies.

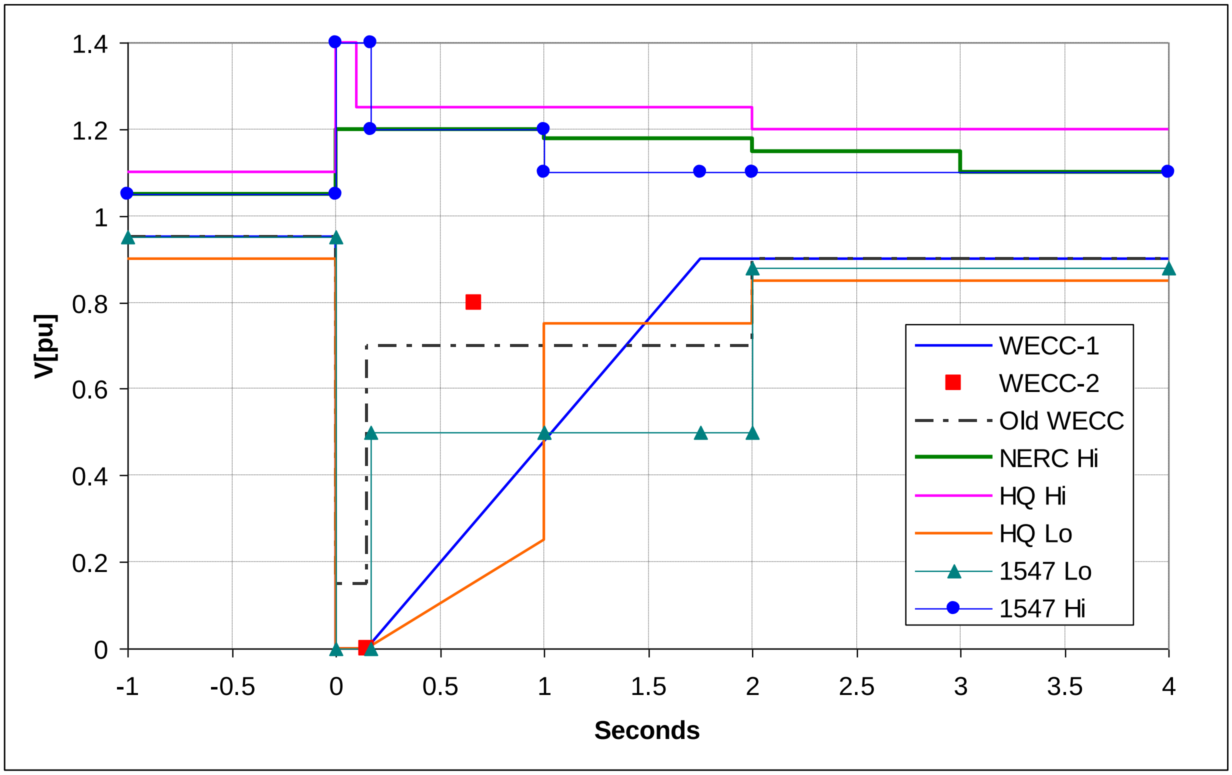


Figure 7 - IEEE 1547 Voltage Tripping with Various LVRT Criteria

References

1. T. E. McDermott, J. C. Smith, "Software Tools for Distributed Wind Applications", in *Proc. AWEA Windpower 2006 Conference*, June 2006, Pittsburgh, PA
2. *IEEE Recommended Practice for Measurement and Limits of Voltage Flicker on AC Power Systems*, IEEE Std. 1453-2004.
3. *Measurement and assessment of power quality characteristics of grid connected wind turbines*, IEC Std. 61400-21 ed. 2, August 2008.
4. J. F. Manwell, J. MacLeod, S. Wright, L. DiTullio, J. G. McGowan, "Hull Wind II: A Case Study of the Development of a Second Large Wind Turbine Installation in the Town of Hull, MA", in *Proc. AWEA Windpower 2006 Conference*, June 2006, Pittsburgh, PA [Online]. Available: http://www.mtpc.org/documents/2006-06-AWEA-wind-Hull2.pdf.
5. W. Henson, "The Electrical Effects of the Hull Near Shore Windfarm Part I: Steady-State Issues and Interconnection Options", RERL UMass Amherst student project report, January 2007 [Online]. Available: http://people.umass.edu/whenson/hnsw_electrical_part_1.pdf
6. W. Henson, "Final Report of the Student Project: Grid Interconnection in Massachusetts", RERL UMass Amherst student project report, August 2007 [Online]. Available: http://people.umass.edu/whenson/ grid_integration_simulation_case.pdf
7. Utility Wind Integration Group, Distributed Wind Impacts Project, [Online]. Available: www.uwig.org/distwind

8. OpenDSS, Distribution System Simulator, [Online]. Available: http://sourceforge.net/projects/electricdss.
9. *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*, IEEE Std. 1547-2003 (reaffirmed 2008).
10. *IEEE Draft Application Guide for IEEE Standard 1547*, IEEE Std. P1547.2, 2008 (approved in January 2009).
11. *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*, IEEE Std. 519-1992.
12. R. A. Walling, R. Saint, R. C. Dugan, J. Burke, L. A. Kojovic, “Summary of Distributed Resources Impact on Power Delivery Systems”, *IEEE Trans. on Power Delivery*, vol. 23, no. 3, July 2008, pp. 1636-1644.
13. Cigre Task Force C6.04.01, “Connection Criteria at the Distribution Network for Distributed Generation”, *Cigre Technical Brochure 313*, February 2007.