Technical Perspectives on Fault Current Injection Requirements in IEEE Std 2800-2022: Clarifications and Recommendations for Improvement

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***Abstract*—IEEE Std 2800-2022 establishes performance requirements for inverter-based resources (IBRs) connecting to the transmission system. Among these, clause 7.2.2.3.4 specifies fault current injection requirements for IBR units (inverters, wind turbine generators, etc.). While the requirements for fault current injection during balanced faults are relatively straightforward, the specifications for unbalanced fault conditions have led to some confusion in interpretation and implementation. This paper dives into understanding the technical basis for these requirements, explores their interpretation challenges, and recommends refinements to support clearer requirements for practical implementations. The discussions and recommendations in this paper are applicable solely to grid-following IBR technology.**

***Index Terms*—Inverter-Based Resource, Fault Current Injection Requirements, IEEE Std 2800-2022.**

I. Introduction

As the penetration of inverter-based resources (IBRs) is increasing and their capability continues to evolve, the IEEE Std 2800TM-2022 [1] was developed, which addresses minimum technical capability and performance requirements for the IBRs. In this first version of the standard, an attempt has been made to strike a balance between state-of-the-art IBR technology and the needs of the future grid. The IBR performance requirements of the standard include, but are not limited to, reactive capability, active and reactive power control, voltage and frequency ride-through capability and performance, power quality, modeling, and measurement data for performance monitoring and validation.

This paper focuses on the fault current injection requirements applicable to IBR units—such as inverters and wind turbine generators (WTGs)—as specified in clause 7.2.2.3.4 of the standard. These requirements play a critical role in protection system performance and grid reliability. However, certain aspects may require clarification or refinement in the next revision of the standard. This paper examines these areas and provides recommendations to enhance clarity and applicability. Note that the focus of this paper is on grid-following technology.

Fig.1 illustrates a typical single-line diagram of an IBR plant. In IEEE Std 2800, the high-side terminal of the main power transformer (MPT) is designated as the point of measurement (POM), where most of the standard's requirements are applied. However, the fault current injection requirements specified in clause 7.2.2.3.4 apply at the IBR unit terminals, referred to as the point of connection (POC). In some cases, the point of connection could be on the high-side of the IBR unit transformer. During voltage ride-through events, each IBR unit typically responds independently based on the voltage at its own terminals. Hence, the current injection requirements are defined at the POC rather than the POM.

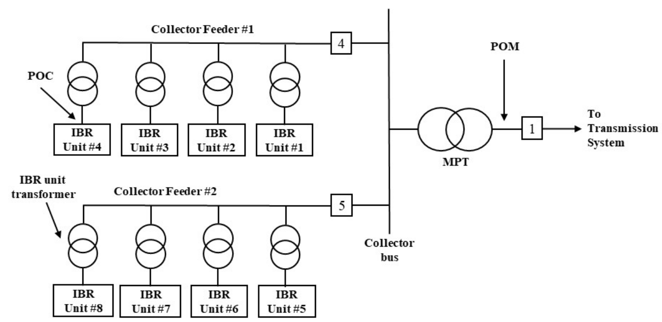

Fig. 1. A typical IBR plant arrangement.

II. Summary of Fault Current Injection Requirements in Clause 7.2.2.3.4

A. General Requirements

IEEE Std 2800 specifies that the type and magnitude of current injection during ride-through operation must depend on the deviation of the IBR terminal voltage from its nominal value. For example, if the IBR unit terminal voltage drops to 0.6 pu during a three-phase fault, the required current injection is based on a 0.4 pu deviation in voltage (1.0 pu nominal minus 0.6 pu). For unbalanced faults, the deviation in negative-sequence voltage during faults is measured from zero, assuming no negative-sequence voltage exists under pre-fault conditions.

Note that the pre-fault IBR unit terminal voltage could range from 0.9 pu to 1.10 pu, depending on reactive power exchange with the grid—lower when absorbing reactive power and higher when supplying it. This raises an important question: should fault current injection be based on deviation from the nominal voltage or from the actual pre-fault operating voltage?

For negative-sequence voltage, deviation is always from zero, but for positive-sequence voltage, deviation could be referenced from either nominal or pre-fault voltage. Using IBR unit nominal voltage as the reference is reasonable for consistency, given that negative-sequence deviation is measured from zero.

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B. Balanced faults

The IEEE Std 2800 states that "for balanced faults, an IBR unit shall inject reactive current dependent of IBR unit terminal (POC) voltage." It further clarifies that "the difference between reactive current injection during a fault and a pre-fault reactive current output is an incremental positive-sequence reactive current (ΔIR-1)" and that "the incremental positive-sequence reactive current shall not be negative." The default operating mode is reactive current priority mode, wherein reactive current is prioritized up to the IBR unit's full current rating, and active current is constrained.

One of the widely used controls in IBR unit is K-factor based proportional control. In this control, the incremental reactive current injection by an IBR unit is proportional to deviation in terminal voltage. For example, when a K-factor is set to 2.0, the IBR unit would inject 60% incremental reactive current for a 30% reduction in IBR unit terminal voltage.

C. Unbalanced faults

For unbalanced faults, the standard states that "IBR unit shall inject negative-sequence current dependent on IBR unit terminal (POC) negative-sequence voltage". The standard further specifies that for full converter-based IBR units (PV inverters, type IV WTGs) the injected negative-sequence current shall lead the IBR unit terminal (POC) negative-sequence voltage by 90-100 degrees. The allowable range for type III WTGs is 90-150 degrees.

Given that IBR unit's pre-fault negative-sequence current would be zero, the standard states that "negative-sequence current injection during a fault is an incremental negative-sequence reactive current (ΔIR-2)." Recognizing current limit of the IBR unit, the standard further states that "if the IBR unit's total current limit is reached, either ΔIR-1 or ΔIR-2, or both may be reduced with a preference of equal reduction in both currents. Additionally, the incremental positive-sequence reactive current (ΔIR-1) injection shall not be reduced below incremental negative-sequence reactive current (ΔIR-2)."

D. Observations

The fault current injection requirements for balanced faults are relatively straightforward. In contrast, the wording of the requirements for unbalanced faults introduces flexibility in control design and performance during fault conditions. However, this flexibility also introduces ambiguity in interpretation, which can result in inconsistent implementation.

- Allowing reduction of either ΔIR-1 or ΔIR-2 independently can result in undesired current in unfaulted phases.
- The preference for equal reduction is not mandatory and becomes ambiguous when ΔIR-1 and ΔIR-2 are not increased equally before reduction.
- The only enforceable requirement is that ΔIR-1 cannot be reduced below ΔIR-2, meaning ΔIR-1 may exceed ΔIR-2. Without visibility into the current-limiting scheme, it is impossible to determine whether reductions are applied to ΔIR-1, ΔIR-2, or both, and whether those reductions are equal. Consequently, when the details of the limiting scheme are unknown, the only enforceable requirement is that ΔIR-1 must not be less than ΔIR-2. Even this requirement has limitations: the comparison between ΔIR-1 and ΔIR-2 is meaningful only when ΔV1 and ΔV2 are nearly equal, such as during a line-to-line fault. When ΔV1 and ΔV2 differ significantly, ΔIR-1 and ΔIR-2 are expected to differ as well, making the requirement that ΔIR-1 cannot be less than ΔIR-2 potentially inappropriate.

Now to understand undesired effect of above requirements, consider a line-to-line (B-C) fault on IBR unit terminals, where the positive-sequence and negative-sequence voltages become equal. Assuming a pre-fault terminal voltage of 1.0 per unit and ignoring current injection from IBR unit, change in positive-sequence voltage (ΔV1) and negative-sequence voltage (ΔV2) are also equal. Under this condition, setting current injection from IBR unit to ΔIR-1 equal to ΔIR-2, results in zero reactive current injection in an unfaulted phase. This behavior is illustrated in Fig. 2, where ΔIR-1 (~55%) is nearly equal to ΔIR-2 (~52.5%). Given that IBR unit reaches its current limit, the active current injection is reduced to zero. The Vist represents the instantaneous voltage at the IBR unit terminal. Due to fault being line-to-line fault, the voltages of the faulted phase voltages (red and green traces) lie directly on top of each other. Given I1R = 0.55∠-90 and I2R = 0.525∠90, the resulting phase currents are: phase a = 0.025∠-90, phase b = 0.93∠179.2, and phase c = 0.93∠0.8. This indicates that the current injection into the unfaulted phase a is minimal, and its terminal voltage remains essentially unchanged during the fault.

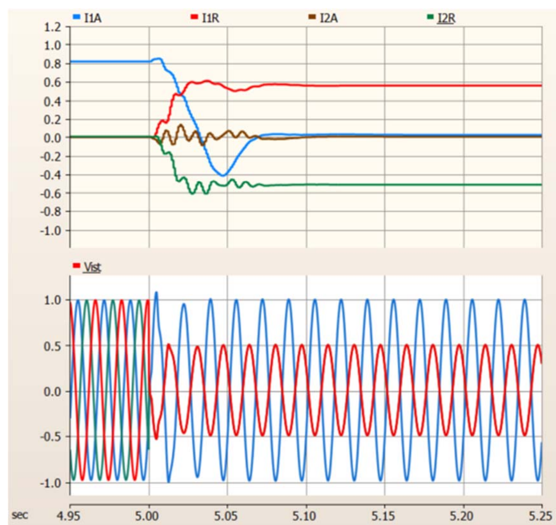

Fig. 2. IBR unit fault response for terminal L-L fault with ΔIR-1 ≈ ΔIR-2

Fig. 3 shows a case where ΔIR-1 > ΔIR-2. In this case, the positive-sequence active current is reduced to zero. With I1R = 0.70∠-90 and I2R = 0.35∠90, the resulting phase currents are: phase a = 0.35∠-90, phase b = 0.93∠169, and phase c = 0.93∠11. The condition ΔIR-1 > ΔIR-2 leads to positive-sequence reactive current injection in the unfaulted phase (i.e., phase a) causing a voltage rise of approximately 10%. Conversely, Fig. 4 demonstrates a scenario where ΔIR-1 < ΔIR-2. In this case also, the positive-sequence active current is reduced to zero. With I1R = 0.30∠-90 and I2R = 0.80∠90, the resulting phase currents are: phase a = 0.50∠90, phase b = 0.98∠-165.3, and

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phase c = 0.98∠-14.7. The condition ΔIR-1 < ΔIR-2 leads to positive-sequence reactive current absorption in the unfaulted phase (i.e., phase a) causing a voltage drop of approximately 10%.

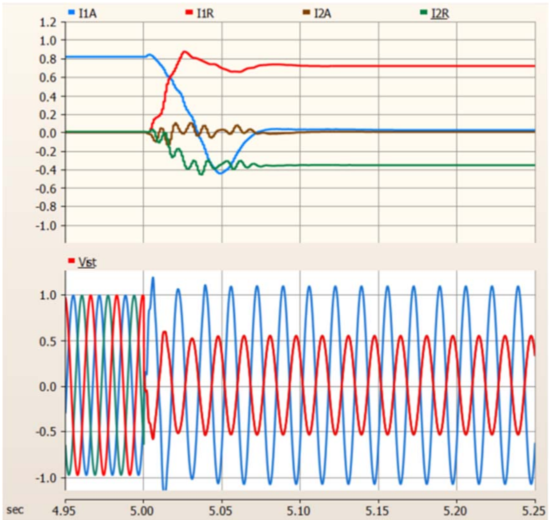

Fig. 3. IBR unit fault response for terminal L-L fault with ΔIR-1 > ΔIR-2

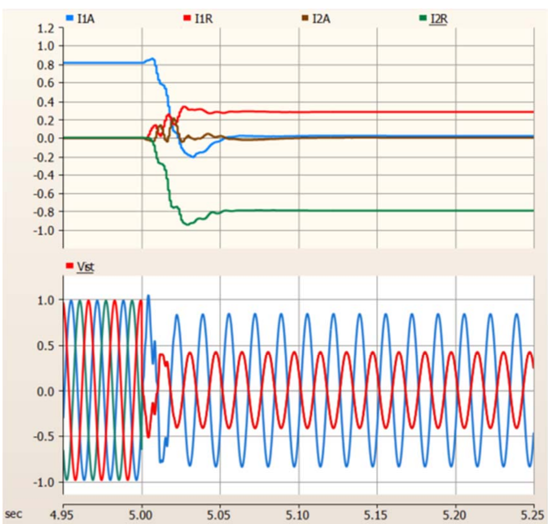

Fig. 4. IBR unit fault response for terminal L-L fault with ΔIR-1 < ΔIR-2

In summary, for a line-to-line fault, unequal values of ΔIR-1 and ΔIR-2 can lead to undesired voltage rise or drop in the unfaulted phase. This behavior underscores the need to revisit and refine the fault current injection requirements in the standard.

III. Case Study

The case study included simulating various unbalanced fault conditions and analyzing the response of a synchronous machine alongside IBR unit from three different original equipment manufacturers (OEMs) in electromagnetic transient (EMT) software. The IBR units in this case study are full converter-based typically used in solar plants. The OEM provided EMT models for IBR units are used. Given the fault current injection requirements are for incremental positive- and negative-sequence currents, consideration of pre-fault operating conditions is important. As such, three different pre-fault operating conditions are considered. The test system incorporating a synchronous machine is shown in Fig. 5, where various unbalanced faults are applied at Bus #1. For the IBR plant, the test system is illustrated in Fig. 6, with various unbalanced faults applied at the point of measurement (POM). Voltages and currents at the terminals of both the synchronous machine and IBR units are monitored, and the results are summarized in Table I through Table IV. Only voltage and current magnitudes are reported. In all cases, the negative-sequence active current is negligible and therefore not included in Table I through Table IV.

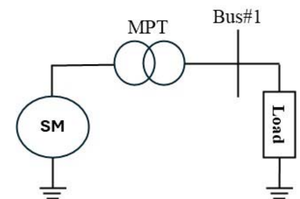

Fig. 5. Synchronous machine test system

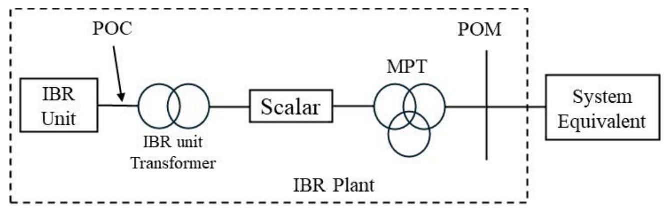

Fig. 6. IBR plant test system

The response of synchronous machines to unbalanced faults is well understood and is included here only for comparison with IBR unit behavior. Table V presents the magnitude of ΔV1/ΔI1-R and ΔV2/ΔI2-R for a synchronous machine. As expected, these ratios remain nearly equal across all fault types and pre-fault operating conditions.

All IBR units included in this case study employ K-factor based control. The K-factor for both positive-sequence and negative-sequence currents is set to 2.0. A few observations for IBR unit response noted in Table II through Table IV are as follows:

- Due to differences in current-limiting algorithms, the positive- and negative-sequence currents injected by IBR units vary.
- Furthermore, because the fault is simulated at the POM, the impedance between the IBR unit and the POM causes the IBR unit terminal voltage to depend on the current injected by the IBR unit.
- For line-to-line and line-to-ground faults, ΔV1 and ΔV2 are almost equal, hence, it becomes easy to compare ΔIR-1 and ΔIR-2 against the requirements in the standard.
- In case of a line-to-line-to-ground fault, ΔV1 > ΔV2, hence comparing ΔIR-1 and ΔIR-2 to verify conformance with requirements in the standard becomes impractical.

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TABLE I. FAULT RESPONSE OF SYNCHRONOUS MACHINE

Fault Type	**Pre-fault Operating Condition**	**Pre-fault**			**Steady-State Condition During Fault**								
		V1 pu	**I1A pu**	**I1R pu**	**V1 pu**	**V2 pu**	**I1A pu**	**I1R pu**	**I2R pu**	**ΔV1 pu**	**ΔIR-1 pu**	**ΔV2 pu**	**ΔIR-2 pu**
B-C	80 MW, 0 MVAr	1.000	0.798	0.063	0.704	0.298	0.712	2.055	-1.975	0.296	1.992	0.298	1.975
	80 MW, 20 MVAr	0.973	0.743	0.246	0.691	0.282	0.673	2.149	-1.888	0.282	1.903	0.282	1.888
	80 MW, -20 MVAr	1.028	0.854	-0.137	0.718	0.310	0.758	1.954	-2.071	0.310	2.091	0.310	2.071
B-C-G	80 MW, 0 MVAr	1.000	0.798	0.063	0.544	0.134	0.453	3.154	-0.898	0.456	3.091	0.134	0.898
	80 MW, 20 MVAr	0.973	0.743	0.246	0.541	0.131	0.446	3.174	-0.879	0.432	2.928	0.131	0.879
	80 MW, -20 MVAr	1.028	0.854	-0.137	0.547	0.138	0.460	3.134	-0.918	0.481	3.271	0.138	0.918
A-G	80 MW, 0 MVAr	1.000	0.798	0.063	0.755	0.245	0.677	1.719	-1.638	0.245	1.656	0.245	1.638
	80 MW, 20 MVAr	0.973	0.743	0.246	0.741	0.232	0.640	1.813	-1.552	0.232	1.567	0.232	1.552
	80 MW, -20 MVAr	1.028	0.854	-0.137	0.770	0.260	0.719	1.613	-1.733	0.258	1.753	0.260	1.733

TABLE II. FAULT RESPONSE OF IBR UNIT BY OEM #1

Fault Type	**Pre-fault Operating Condition**	**Pre-fault**			**Steady-State Condition During Fault**								
		V1 pu	**I1A pu**	**I1R pu**	**V1 pu**	**V2 pu**	**I1A pu**	**I1R pu**	**I2R pu**	**ΔV1 pu**	**ΔIR-1 pu**	**ΔV2 pu**	**ΔIR-2 pu**
B-C	80 MW, 0 MVAr	0.992	0.861	0.000	0.604	0.398	0.275	0.466	-0.505	0.388	0.466	0.398	0.505
	80 MW, 20 MVAr	1.040	0.822	0.145	0.622	0.418	0.217	0.519	-0.434	0.418	0.374	0.418	0.434
	80 MW, -20 MVAr	0.940	0.909	-0.160	0.473	0.374	0.368	0.375	-0.581	0.367	0.535	0.374	0.581
B-C-G	80 MW, 0 MVAr	0.992	0.861	0.000	0.460	0.253	0.240	0.652	-0.323	0.532	0.652	0.253	0.323
	80 MW, 20 MVAr	1.040	0.822	0.145	0.469	0.263	0.234	0.689	-0.286	0.571	0.544	0.263	0.286
	80 MW, -20 MVAr	0.940	0.909	-0.160	0.445	0.239	0.249	0.600	-0.372	0.495	0.760	0.239	0.372
A-G	80 MW, 0 MVAr	0.992	0.861	0.000	0.724	0.275	0.551	0.343	-0.355	0.268	0.343	0.275	0.355
	80 MW, 20 MVAr	1.040	0.822	0.145	0.768	0.282	0.455	0.477	-0.345	0.272	0.332	0.282	0.345
	80 MW, -20 MVAr	0.940	0.909	-0.160	0.682	0.267	0.613	0.206	-0.363	0.258	0.366	0.267	0.363

TABLE III. FAULT RESPONSE OF IBR UNIT BY OEM #2

Fault Type	**Pre-fault Operating Condition**	**Pre-fault**			**Steady-State Condition During Fault**								
		V1 pu	**I1A pu**	**I1R pu**	**V1 pu**	**V2 pu**	**I1A pu**	**I1R pu**	**I2R pu**	**ΔV1 pu**	**ΔIR-1 pu**	**ΔV2 pu**	**ΔIR-2 pu**
B-C	80 MW, 0 MVAr	0.993	0.852	0.002	0.621	0.398	0.207	0.523	-0.514	0.372	0.521	0.398	0.514
	80 MW, 20 MVAr	1.039	0.814	0.143	0.634	0.406	0.125	0.573	-0.492	0.405	0.430	0.406	0.492
	80 MW, -20 MVAr	0.946	0.892	-0.142	0.602	0.392	0.288	0.463	-0.525	0.344	0.605	0.392	0.525
B-C-G	80 MW, 0 MVAr	0.993	0.852	0.002	0.488	0.253	0.069	0.750	-0.342	0.505	0.748	0.253	0.342
	80 MW, 20 MVAr	1.039	0.814	0.143	0.489	0.256	0.071	0.766	-0.328	0.550	0.623	0.256	0.328
	80 MW, -20 MVAr	0.946	0.892	-0.142	0.478	0.245	0.118	0.714	-0.362	0.468	0.856	0.245	0.362
A-G	80 MW, 0 MVAr	0.993	0.852	0.002	0.751	0.257	0.494	0.439	-0.434	0.242	0.437	0.257	0.434
	80 MW, 20 MVAr	1.039	0.814	0.143	0.776	0.259	0.412	0.519	-0.436	0.263	0.376	0.259	0.436
	80 MW, -20 MVAr	0.946	0.892	-0.142	0.724	0.256	0.562	0.356	-0.424	0.222	0.498	0.256	0.424

TABLE IV. FAULT RESPONSE OF IBR UNIT BY OEM #3

Fault Type	**Pre-fault Operating Condition**	**Pre-fault**			**Steady-State Condition During Fault**								
		V1 pu	**I1A pu**	**I1R pu**	**V1 pu**	**V2 pu**	**I1A pu**	**I1R pu**	**I2R pu**	**ΔV1 pu**	**ΔIR-1 pu**	**ΔV2 pu**	**ΔIR-2 pu**
B-C	80 MW, 0 MVAr	0.995	0.856	0.000	0.636	0.388	0.000	0.586	-0.563	0.359	0.586	0.388	0.563
	80 MW, 20 MVAr	1.041	0.817	0.150	0.645	0.397	0.000	0.617	-0.534	0.396	0.467	0.397	0.534
	80 MW, -20 MVAr	0.944	0.904	-0.147	0.624	0.378	0.000	0.550	-0.600	0.320	0.697	0.378	0.600
B-C-G	80 MW, 0 MVAr	0.995	0.856	0.000	0.493	0.245	0.000	0.782	-0.370	0.502	0.782	0.245	0.370
	80 MW, 20 MVAr	1.041	0.817	0.150	0.493	0.245	0.000	0.781	-0.370	0.548	0.631	0.245	0.370
	80 MW, -20 MVAr	0.944	0.904	-0.147	0.489	0.241	0.000	0.765	-0.384	0.455	0.912	0.241	0.384
A-G	80 MW, 0 MVAr	0.995	0.856	0.000	0.789	0.237	0.326	0.568	-0.526	0.206	0.568	0.237	0.526
	80 MW, 20 MVAr	1.041	0.817	0.150	0.815	0.240	0.221	0.653	-0.530	0.226	0.503	0.240	0.530
	80 MW, -20 MVAr	0.944	0.904	-0.147	0.761	0.235	0.426	0.477	-0.521	0.183	0.624	0.235	0.521

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TABLE V. ΔV1/ΔIR-1 AND ΔV2/ΔIR-2 FOR SYNCHRONOUS MACHINE

Fault Type	Pre-Fault Operating Condition	|ΔV1/ΔIR-1|	|ΔV2/ΔIR-2|
B-C	80 MW, 0 MVAr	0.149	0.149
	80 MW, 20 MVAr	0.148	0.148
	80 MW, -20 MVAr	0.148	0.148
B-C-G	80 MW, 0 MVAr	0.148	0.148
	80 MW, 20 MVAr	0.148	0.148
	80 MW, -20 MVAr	0.147	0.147
A-G	80 MW, 0 MVAr	0.148	0.148
	80 MW, 20 MVAr	0.148	0.148
	80 MW, -20 MVAr	0.147	0.147

Table VI presents magnitude of ΔV1/ΔI1-R and ΔV2/ΔI2-R for IBR units by all three OEMs across all pre-fault operating conditions. Due to current limiting scheme of IBR units, it is not expected that magnitude of ΔV1/ΔI1-R is nearly equal to ΔV2/ΔI2-R for all fault types. However, for a given fault type, the magnitude of ΔV1/ΔI1-R should be nearly equal to ΔV2/ΔI2-R across all pre-fault operating conditions. As illustrated in Fig. 7, except for a couple of outliers, the difference between ΔV1/ΔI1-R and ΔV2/ΔI2-R for IBR unit by OEM #1 is minimal. However, the same is not true with IBR units by OEM #2 and OEM #3.

TABLE VI. ΔV1/ΔIR-1 AND ΔV2/ΔIR-2 FOR IBR UNITS

Fault Type	Pre-Fault Operating Condition	|ΔV1/ ΔIR-1|	|ΔV2/ ΔIR-2|	Difference (%)
OEM #1				
B-C	80 MW, 0 MVAr	0.833	0.788	4.45
	80 MW, 20 MVAr	1.118	0.963	15.45
	80 MW, -20 MVAr	0.686	0.644	4.23
B-C-G	80 MW, 0 MVAr	0.816	0.783	3.27
	80 MW, 20 MVAr	1.050	0.920	13.01
	80 MW, -20 MVAr	0.651	0.642	0.88
A-G	80 MW, 0 MVAr	0.781	0.775	0.67
	80 MW, 20 MVAr	0.819	0.817	0.19
	80 MW, -20 MVAr	0.705	0.736	3.06
OEM #2				
B-C	80 MW, 0 MVAr	0.714	0.774	6.03
	80 MW, 20 MVAr	0.942	0.825	11.67
	80 MW, -20 MVAr	0.569	0.747	17.81
B-C-G	80 MW, 0 MVAr	0.675	0.740	6.46
	80 MW, 20 MVAr	0.883	0.780	10.23
	80 MW, -20 MVAr	0.547	0.677	13.01
A-G	80 MW, 0 MVAr	0.554	0.592	3.84
	80 MW, 20 MVAr	0.699	0.594	10.54
	80 MW, -20 MVAr	0.446	0.604	15.78
OEM #3				
B-C	80 MW, 0 MVAr	0.613	0.689	7.65
	80 MW, 20 MVAr	0.848	0.743	10.45
	80 MW, -20 MVAr	0.459	0.630	17.09
B-C-G	80 MW, 0 MVAr	0.642	0.662	2.02
	80 MW, 20 MVAr	0.868	0.662	20.63
	80 MW, -20 MVAr	0.499	0.628	12.87
A-G	80 MW, 0 MVAr	0.363	0.451	8.79
	80 MW, 20 MVAr	0.449	0.453	0.353
	80 MW, -20 MVAr	0.293	0.451	15.78

IV. RECOMMENDATION

During unbalanced faults, the IBR unit must reduce positive- and negative-sequence reactive currents in some proportion to maintain the net current in each phase below its current limit. The IEEE Std 2800 recognizes this and allows a flexibility by stating that "*if the IBR unit's total current limit is reached, either ΔIR-1 or ΔIR-2, or both may be reduced with a preference of equal reduction in both currents. Additionally, the incremental positive-sequence reactive current (ΔIR-1) injection shall not be reduced below incremental negative-sequence reactive current (ΔIR-2).*" However, this requirement is ambiguous and may result in undesired fault current.

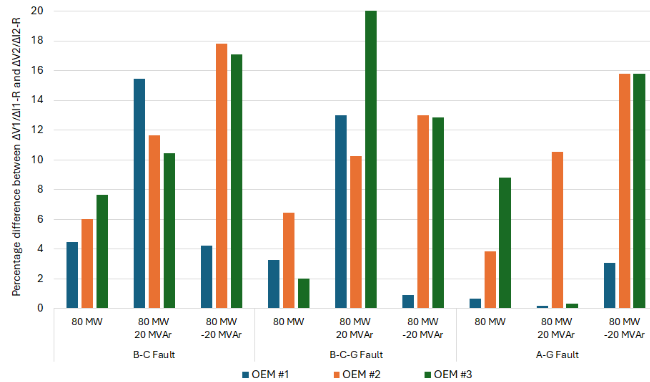

Fig. 7. Comparison of difference between ΔV1/ΔI1-R and ΔV2/ΔI2-R across all faults and pre-fault operating conditions

Considering grid needs, the requirement in the standard should be updated to state that, if the IBR unit's total current limit is reached, the reduction in ΔIR-1 or ΔIR-2 shall be such that the relationship between positive- and negative-sequence voltage and current deviation is maintained, as follows:

$$\frac{\Delta V1}{\Delta IR-1} \approx \frac{\Delta V2}{\Delta IR-2}$$

Recognizing the practical challenges associated with implementing controls, the standard should permit a reasonable tolerance, on the order of less than 5%. A requirement written in this manner would also yield acceptable performance for all types of unbalanced faults. The example of this is shown in Fig. 2. The performance of current limit logic in a generic electromagnetic transient model detailed in [2] could serve as a great reference.

V. CONCLUSION/SUMMARY

Clause 7.2.2.3.4 of IEEE Std 2800-2022 specifies fault current injection requirements for IBR units. While the requirements for balanced faults are straightforward, those for unbalanced faults appear ambiguous and challenging to enforce without knowledge of the current limiting logic implemented in IBR unit. Furthermore, the resulting fault current behavior may not align with grid needs. This paper highlights these issues and provides recommendations for consideration in the next revision of the standard. Note that the discussions and recommendations in this paper are applicable solely to grid-following IBR technology.

REFERENCES

[1] IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems," in IEEE Std 2800-2022, vol., no., pp.1-180, 22 April 2022, doi: 10.1109/IEEESTD.2022.9762253.

[2] W. Wes Baker, M. Patel, A. Haddadi, E. Farantatos and J. C. Boemer, "Inverter Current Limit Logic based on the IEEE 2800-2022 Unbalanced Fault Response Requirements," 2023 IEEE Power & Energy Society General Meeting (PESGM), Orlando, FL, USA, 2023.