A Comparison of North American (ANSI) and European (IEC) Fault Calculation Guidelines

Anthony J. Rodolakis, *Member, IEEE*

***Abstract*— The need for accurate fault analysis studies in industrial and transmission systems necessitated development of specific guidelines for short-circuit computations in North America (ANSI) and in Europe (IEC). Differences in fault current duty types, system component modeling, and computational procedures encountered between these two guidelines raise the question of whether results produced by computations adhering to either one can accommodate both. Because engineering services exchange between continents is on the rise, this question has become increasingly pertinent. This article compares the salient features of the two fault computation guidelines from the points of view of system modeling, computational procedures, and database requirements. Differences encountered in breaker rating structures between ANSI and IEC are not dealt with.**

I. Introduction and Methodology

SHORT CIRCUIT analysis is one of the major tasks related to the analysis and planning of electric power systems. Switchgear selection and protection studies require detailed and rather accurate short-circuit simulations. As a result, significant attention has been devoted to compiling fault analysis procedures in the form of standards, embodying the best compromise between accuracy and simulation simplicity.

The North American standard outlining these procedures is the ANSI/IEEE standard 141 [4], which is a companion to the parent standard C37 [1], [2]. Their recently published European counterpart is the IEC 909 guide [5], which addresses systems with rated voltages as high as 230 KV. The IEC 909 resembles the earlier VDE 0102 German standard [6] and is the core around which fault calculation procedures are being standardized in Europe.

A comparative assessment of the two standards in terms of system modeling is fundamental to bringing into focus their salient differences and to directing the attention of the user to the main factors affecting the results.

A comparison of the database requirements, apart from providing a direct index of the equipment modeling complexity, establishes the minimum common denominator for information exchange. An industrial system with rotating load covering a variety of ratings was used for the simulations. The system frequency was considered to be 60 Hz. Three-phase faults are simulated only, the various duty types covered by both guidelines are examined, and the pertinent results, comments, and conclusions are presented. Results and data are presented for all buses of the sample network except bus 6 (identical to bus 5), buses 8, 9, 10 (identical to bus 7), buses 12 and 13 (identical to bus 11), and bus 15 (identical to bus 14). The assumptions undertaken during the course of this analysis are outlined in the pertinent sections.

The computational intensiveness associated with the study was circumvented by using simulation packages adhering to the two guidelines. Last, but not least, it should be made clear that it is not the intent of this work to either criticize or endorse either of the two guidelines.

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The author is with CYME International, Inc., St. Bruno, CA J3V 3P8.

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II. Background

A. General

With the end result of fault analysis studies being, usually, switchgear rating and/or protective device coordination, the question of correctly accounting for ac and dc decay in the fault currents becomes central. AC decay is associated with the inherent tendency of machines to increase their reactances with time from the onset of the short circuit, whereas dc decay is closely linked with the exact interrupting moment and the damping properties of the interrupted circuit.

Full transient analysis of multimachine networks is circumvented by adopting some modeling assumptions, allowing us to analyze linear networks and still properly address these concerns. It is these rules incorporated in the standards that are subsequently analyzed. It is not the intend of this paper to provide an exhaustive description of either standard. The interested reader should refer to the appropriate clauses of either standard for further details.

B. Duty Types

The types of fault currents recognized by the two standards are listed in Table I. The conceptual association created by listing these duty types in pairs should not, by any means, mask the fact that these currents are qualitatively different, as explained in the following sections.

C. ac Decay Modeling Aspects

When calculating symmetrical interrupting currents, ANSI recommends multipliers for the subtransient/transient reactances of rotating equipment. These multipliers are a function of the duty type (to approximately account for the time elapsed from the onset of the fault), machine size (horsepower), and

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TABLE I
DUTY TYPES PER ANSI AND IEC 909

Duty type	ANSI Currents	IEC 909 Currents
1	First cycle	Initial (I"k)
2	Closing-Latching	Peak (Ip)
3	Interrupting	Breaking (Ib)
4	Time delayed	Steady state (Ik)

TABLE II
ANSI MACHINE REACTANCE MULTIPLIERS

Machine type network	First cycle network	Interrupting
Turboalternators	1.00 X"d	1.00 X"d
Hydro with Dampers	1.00 X"d	1.00 X"d
Condensers	1.00 X"d	1.00 X"d
Hydro no Dampers	0.75 X'd	0.75 X'd
Sync. Motors	1.00 X"d	1.50 X"d
Induction Motors		
Larger than 1000Hp 1800rpm or less	1.00 X"d	1.50 X"d
Above 250 HP at 3600 rpm	1.00 X"d	1.50 X"d
All others 50 HP and above	1.20 X"d	3.00 X"d
Smaller than 50 HP	1.67 X"d	Neglect

speed (revolutions per minute). Noteworthy attributes of theirs are that they are independent of the machine proximity to the fault and the contact parting time. Table II lists the recommended ANSI multipliers with provisions for single first-cycle analysis of systems comprising low-voltage circuits.

IEC 909 recommends no "*a priori*" reactance adjustment multipliers for the rotating load. AC decay is modeled by considering machine type, size, and speed (megawatts per pole pair), exact breaker parting time, and machine proximity to the fault (see Appendix A). IEC guidelines do not rely on curves for modeling ac decrement for generating stations, which is a technique favored in both ANSI C37.5 and ANSI C37.010.

Furthermore, ANSI guidelines classify the fault as "local" or "remote" by quantifying only generator contribution to the fault. On the other hand, IEC guidelines classify faults as "near to generator" (ac decrement present) by quantifying generator and rotating load contribution as well. The concept of "near" or "far" from generator fault is central for IEC machine modeling in breaking and steady-state fault current calculations.

TABLE III
IEC PREFAULT VOLTAGE FACTORS

Nominal Voltage in KV	Voltage factor	
	Maximum fault KA	Minimum fault KA
.23 and .4 KV	1.00	0.95
Other < 1.00 KV	1.05	1.00
1.00 - 230 KV	1.10	1.00

D. dc Decay Modeling Aspects

ANSI [1], [2], [4] recommends applying multipliers to the symmetrical fault currents to obtain the asymmetrical currents. A central concept in ANSI-based dc decay computations is the X/R ratio at the fault point. The same standards require a reactance network for determining the equivalent reactance at the fault point and a separate resistance network for the equivalent resistance. Their ratio is the X/R ratio required to determine the needed multipliers. The approach is recommended in order to safely account for the numerous time constants present in multimachine systems.

IEC 909 does not universally endorse the concept of the single X/R ratio. Instead, more than one X/R ratio, in general, has to be considered. This technique, which is applied when independent sources feed the fault, is based on superposition principles. These notions apply for peak currents as well as for the calculation of the dc component of the asymmetrical breaking currents. It is this latter technique that departs conceptually and computationally from the ANSI guidelines.

E. Prefault Voltages

ANSI guidelines recommend a 1.0 pu prefault voltage at the faulted busbar. IEC 909 recommends that multiplying factors be applied to the prefault voltage to account for transformer taps, system loads and shunts, rotating machinery subtransient behavior, etc. per Table III. Different prefault voltage factors are to be applied for the calculation of maximum and minimum fault currents. In this paper, only maximum IEC fault currents are considered.

On account of the prefault voltage factors, IEC recommends some adjustment to the equivalent impedance of utility interconnections and generators. The adjustment accounts for prefault generator loading and the voltage factor itself [5]. In some cases, this may extend to the transformers associated with generating stations. For the purpose of this work, no prefault load was assumed.

III. INITIAL FAULT CURRENTS

ANSI defines first cycle symmetrical currents as the fault currents immediately after fault initiation. IEC 909 defines initial fault current as the prospective fault current available at the fault point at the onset of the fault (zero time) with

TABLE IV
ANSI VERSUS IEC INITIAL SYMMETRICAL FAULT CURRENTS

BUS #	BUS KV	ANSI		IEC 909
		I-3ph (AMPS)	X/R	I-3ph (AMPS)
1	13.8	26144	30.58	27095
2	4.2	32664	13.71	35564
3	4.2	13207	25.05	15037
4	4.2	20228	5.498	22130
5	2.4	33868	18.65	36912
7	0.48	38423	10.06	44122
11	0.48	36354	10.05	41979
14	0.48	32261	11.07	37838
21	13.80	18337	4.024	19450
22	2.40	28369	20.12	30040
111	69.00	9934	22.48	10046
222	46.00	10703	9.366	10776

the impedances unchanged. Both currents are symmetrical fault currents and can be compared. Calculations performed on the sample system for this type of duty gave the results summarized in Table IV.

It is seen that initial IEC fault currents are found to be higher than the first cycle symmetrical ANSI currents. This behavior can be attributed to the higher prefault voltages recommended by IEC and to the fact that subtransient impedances are used for IEC initial current calculations for all types of rotating loads.

IV. CLOSING/LATCHING CURRENTS

Closing/latching duty currents are asymmetrical fault currents that are customarily computed at half cycle after fault initiation. ANSI recommends the same network as for first cycle duty because at half cycles, machine modeling remains valid. Provisions for asymmetry recommend, as a rule, a multiplier of 1.6. This is assuming an X/R ratio of 25 at 0.5 cycles (variable C) in (2), expressing the remote multiplying factor with ac decrement neglected:

$$\text{M.Fr} = \sqrt{1.0 + 2.0e^{-(4\pi \quad C \quad R/X)}}. \tag{2}$$

Table V portrays the multipliers obtained from (2) and the half-cycle asymmetrical ANSI currents. IEC guidelines do not explicitly provide for half-cycle asymmetrical currents. For comparison purposes, IEC half-cycle currents were calculated and are also shown in Table V. AC decay was not modeled for the IEC network either.

V. PEAK CURRENTS

A single X/R can be used, per IEC to compute the peak current for the case that the contribution to the short circuit comes form a meshed network. IEC 909 guidelines recommend three techniques for calculating that single X/R

TABLE V
ANSI VERSUS IEC HALF-CYCLE CURRENTS

BUS #	ANSI		IEC
	Multip.	Amps	Amps
1	1.6212	42387	43264
2	1.5049	49156	53871
3	1.5988	21116	25085
4	1.2797	25887	24391
5	1.5582	52773	60839
7	1.4376	55238	67103
11	1.4388	52308	63661
14	1.4607	47125	58072
21	1.1915	21846	21902
22	1.5695	44527	48209
111	1.5850	15746	16106
222	1.4221	15221	15387

ratio [5], none of which is the ANSI separate reduction approach. These techniques are the "dominant X/R ratio," the "equivalent X/R ratio at the fault point," and the "equivalent frequency" approach. For the first technique, the X/R ratio of the branch (which may be composed of several elements) carrying at least 80% of the fault current is defined as the dominant X/R ratio. For the third technique, an equivalent frequency source (20 Hz for a 50-Hz system and 24 Hz for a 60-Hz system) is considered to excite the network at the fault point, and the equivalent fault impedance $Zc = Rc + jXc$ is calculated. The sought X/R is computed per (3):

$$X/R = (Xc/Rc)^{*}(f/fc) \tag{3}$$

where f is the frequency of the system. The peak fault current is then obtained from the initial fault current as follows:

$$Ip = \sqrt{2}KI''k \tag{4}$$

with K calculated by (4a):

$$k = \sqrt{2}(1.02 + 0.98e^{3.R/X}). \tag{4a}$$

For the "dominant X/R ratio" technique, the factor K is not to exceed 1.8 for low-voltage systems.

When the second technique is applied, the factor K is calculated as follows:

$$k = 1.15\sqrt{2}(1.02 + 0.98e^{-3.R/X}). \tag{4b}$$

The factor 1.15 is a safety factor that accounts for network meshing. K is not to exceed 1.8 and 2.0 for low- and high-voltage networks, respectively.

For ANSI calculations, the following equation is often used [3] for the same multiplier (crest factor):

$$k = \sqrt{2}(1.0 + \sin(\varphi)e^{-(\varphi + 1.5708)R/X}) \tag{4c}$$

and $\varphi = \arctan(X/R)$ at the fault point.

The X/R ratio is to be calculated from separate reactance and resistance networks. Table VI pictures the ANSI-calculated crest factors as well as the corresponding peak

TABLE VI
ANSI VERSUS IEC PEAK FAULT CURRENTS

BUS	ANSI			IEC 909
#	X/R	Crest F.	AMPS	AMPS
1	30.58	2.6904	70338	72915
2	13.71	2.5436	83084	94711
3	25.05	2.6625	35164	41377
4	5.498	2.2250	45007	46994
5	18.65	2.6102	88402	103367
7	10.06	2.4583	94455	111077
11	10.05	2.4538	89205	105621
14	11.07	2.4823	80081	95084
21	4.024	2.0820	38178	42657
22	20.12	2.6245	73205	83173
111	22.48	2.6450	26275	26905
222	9.366	2.4308	26017	26533

currents. IEC peak currents were calculated using the second above mentioned method and are displayed in the same table. It is seen that there is a trend for higher IEC peak current estimates.

VI. ANSI INTERRUPTING VERSUS IEC BREAKING CURRENTS

A. Symmetrical Currents

Interrupting currents are the currents sensed at contact parting initiation. ANSI guidelines recommend machine reactance adjustment (Table II) for this duty. IEC breaking current computations recommend no initial reactance adjustment associated to ac decay modeling. One IEC clause recommends, as a simplification, the symmetrical breaking current to be taken equal to the initial fault current. When this clause is applied, the estimated breaking currents are higher than the real breaking currents. A more refined calculation technique recommends the symmetrical breaking fault current to be calculated by taking into account exact parting time, machine type, and machine proximity to the short circuit.

For the case where the breaking currents are taken to be the initial currents, IEC breaking currents are invariably higher than their ANSI counterparts. This can be attributed to the lack of ac decrement modeling in the IEC case, whereas for the ANSI case, machine reactances have been increased to account for ac decay. When ac decay is accounted for in the IEC simulations, results are very much governed by the differences of ac decay modeling between the two guidelines. To illustrate these generic differences, results for various interrupting times have been generated. Table VII portrays the symmetrical IEC breaking currents for the IEC standard tabulated contact parting times. Table VIII portrays the same results when no voltage factors are taken into account in the IEC simulations.

AC decay modeling for both guidelines is quantified in Table IX, which shows the equivalent multiplying factors for the machine reactances used when no prefault voltage factors are accounted for. The table applies to faults at machine terminals and was compiled according to Appendix A.

For busbars at which the appreciable part of the fault current is furnished by rotating equipment, the effect of the multipliers outlined in Table IX becomes noticeable. Fault currents at generator busbars 1 and 22 experience more decay than fault currents at the utility infeed points 111 and 222 for which ac decay-related reactance adjustment was blocked in the IEC simulations. At busbar 5 (synchronous motors), ANSI results compare better with IEC results only at higher clearing times for which the reactance multipliers for the motors become comparable. At busbar 3 (large induction motors), we see the

TABLE VII
ANSI VERSUS IEC BREAKING CURRENTS

BUS	ANSI	IEC 909 I-3ph AMPS			
#	I-3ph (AMPS)	.02 secs	.05 secs	.1 secs	.25 secs
1	24701	24694	22723	21332	20211
2	28651	32070	28922	26578	24695
3	10855	13563	12134	11101	10251
4	18311	20181	18136	16552	15160
5	31232	35986	35092	34636	34011
21	17635	17945	16664	15753	14967
22	27623	28238	26625	25506	24576
111	9882	9913	9806	9729	9658
222	10662	10774	10772	10772	10771

TABLE VIII
ANSI VERSUS IEC BREAKING CURRENTS, NO VOLTAGE FACTORS

BUS	ANSI	IEC 909 I-3ph AMPS			
#	I-3ph (AMPS)	.02 secs	.05 secs	.1 secs	.25 secs
1	24701	24204	22372	21090	20090
2	28651	30588	27695	25516	23738
3	10855	12496	11209	10265	9477
4	18311	19221	17583	16320	15097
5	31232	33214	32515	32200	31718
21	17635	17131	16015	15232	14581
22	27623	26475	25132	24013	23083
111	9882	9869	9793	9743	9685
222	10662	10711	10711	10711	10711

TABLE IX
REACTANCE MULTIPLIERS (FAULT AT TERMINALS)

Rotating Equipment Type	ANSI	IEC-909			
		.02s	.05s	0.1s	0.25s
Generators	1.0	1.15	1.34	1.51	1.69
Sync. Motors	1.5	1.10	1.21	1.30	1.42
Ind. Motors (1.74MVA)	1.5	1.14	1.69	2.63	6.97

TABLE X
ASYMMETRICAL BREAKING CURRENTS

BUS	ANSI		IEC 909			
	I-3 p		I3p(Ib=Ik")		I3p(ref.)	
#	.05s	.02s	.05s	.02s	.05s	.02s
1	29420	36011	32734	38981	28870	37352
2	30056	36868	37177	45024	30884	42318
3	12806	15588	18019	22219	15679	21249
4	18316	18902	22255	22506	18289	20592
5	34348	45099	41730	52472	40129	51824
21	17636	18017	19450	19555	16664	18059
22	30148	38166	33704	41626	30699	40345
111	11467	13798	11781	14390	11577	14298
222	10846	12554	10976	12777	10972	12775

effect of a pessimistic reactance for IEC at .02 s and how the result is reversed for higher clearing times. It is mentioned at this point that better agreement was obtained for bus 3 when time constant considerations were accounted for in the ANSI simulations [1].

Table IX indicates that with the exception of generators, effective reactances used by IEC tend to be lower than the ANSI ones for short clearing times. Comparing the results of Tables VII and VIII, it is seen that despite the higher prefault IEC voltages, the effect of reactance adjustment becomes predominant for higher clearing times.

B. Asymmetrical Currents

ANSI guidelines recommend obtaining the asymmetrical fault currents using multipliers applied to the symmetrical interrupting fault currents. These multipliers are obtained from curves parametrized against the breaker contact parting time and the interrupting network X/R ratio at the fault point. Two sets of curves are considered, depending on whether the fault current is fed by local or remote sources. The total asymmetrical fault current is obtained by properly weighting the local and remote contribution [4].

IEC 909 does not rely on curves for asymmetrical breaking current calculations. Procedures similar to the ones governing peak current calculations are to be applied to estimate the dc component of the fault current. Asymmetrical ANSI and IEC currents are shown in Table X for 3 and 1.2 cycles (0.05 s and 0.02 s, respectively).

If symmetrical breaking currents are taken to be equal to the initial fault currents ($Ib = I''k$), IEC asymmetrical fault currents are higher than the corresponding ANSI asymmetrical interrupting currents. This can be attributed to the lack of ac decay modeling in the IEC simulations.

If symmetrical IEC currents are calculated with ac decay present, the results are in better agreement because both ANSI and IEC model ac decay. In view of the fact that the magnitude of the dc content estimates is the same for both IEC simulations, the deviation in the results can now be traced to the differences in ac decay modeling between the two guidelines.

TABLE XI
IEC VERSUS ANSI TIME-DELAYED CURRENTS

BUS	ANSI	IEC 909			
#	I-3p	I-3p	I-3p (With Exciters)		
	X'd	Initial	Max.	Interm.	Min.
1	20969	23104	14090	13432	11466
2	23013	25446	22410	22079	21040
3	8299	9146	8834	8585	7737
4	15105	16664	15150	14861	13886
5	25720	28302	26351	24223	16659
7	30941	32490	32490	32490	32490
11	28029	29452	29452	29452	29452
14	22445	23581	23581	23581	23581
21	15730	17329	11544	10897	8928
22	21181	27963	17631	17054	15262
111	9717	9881	9278	9178	8851
222	10580	10656	10602	10577	10497

VII. ANSI DELAYED VERSUS STEADY-STATE CURRENTS

Both guidelines recognize that transient effects have subsided and, therefore, are not to be modeled. ANSI recommends a network comprising only generators [1] represented by virtue of either their transient or a higher reactance. One clause of IEC implicitly recommends using the generator reactances taken for initial current computations by stipulating that "the steady state fault current is the initial fault current calculated without motors." There are, however, clauses in IEC that, for this type of duty, provide for generator excitation system representation. In modeling the excitation system, these clauses discriminate between salient and round rotor generators and account for maximum, intermediate, and minimum excitation settings. The fault current contributed by each generator now becomes a function of its rated current [5], [6] by virtue of multipliers obtained from curves parameterized against the saturated leakage reactance of the generator, the excitation setting, and the machine type (turbo or salient). The same provisions may also apply for synchronous motors, depending on whether their excitation systems are bus-fed or not. It is these clauses that depart considerably from the ANSI-based procedures. Results for the sample system are summarized in Table XI. Transient reactances were used for the ANSI simulations. IEC results are presented for both techniques. For the simulations entailing more detailed generator modeling, results for all three excitation settings were generated for illustration purposes. No motors were considered in the IEC simulations.

When the simplified IEC clause is used, differences with the ANSI simulations are mainly attributed to the different reactances used. It is also seen that results obtained with the simplified IEC clause will yield pessimistic estimates for faults near generation, as compared with the results of the alternative IEC clauses requiring inclusion of exciter modeling. Both IEC modeling techniques, however, will give the same results for busbars remote from generation.

VIII. Database Requirements

A. Positive Sequence Network Data

Both guidelines recommend omitting static loads and positive sequence line charging. Series resistances and reactances of lines and transformers are mandatory data for both. IEC 909 also accounts for transformers whose nominal winding voltages are different from the nominal system rated voltages (noncoherent systems). In order to properly address these concerns, in general, access to a load flow-type database and to software accounting for system shunts in positive sequence may be necessary.

B. Negative Sequence Data

IEC guidelines recommend that negative sequence impedances be modeled for unbalanced faults. This may necessitate, for computer solutions, the cost of formulating a negative sequence matrix for the system, which is a computational burden not often undertaken in ANSI simulations.

C. Zero Sequence Network Data

Both guidelines require zero sequence series impedances for lines and transformers. For solidly grounded systems, neglecting zero sequence line charging is acceptable by both guidelines because the results will be conservative. For isolated or resonant grounded systems, however, IEC requires modeling of zero sequence line shunts, which is a provision that is not endorsed by ANSI. Furthermore, zero sequence generator impedances require adjustment per IEC (on account of prefault loading and voltage factors), whereas ANSI does not stipulate such an adjustment.

D. Generator Data

Common generator data comprise subtransient impedances, number of poles, rated voltage, and rated MVA. Steady-state fault current IEC calculations require the saturated leakage reactance (or the short-circuit ratio) of the generator to account for excitation system response modeling. The prefault power factor of the generator may also be required (impedance adjustment) when the prefault loading condition of the generator is of interest. On the other hand, ANSI may require the transient reactance of generators for time delayed calculations.

E. Motor Data

Induction motor data requirements for both guidelines are met by providing locked rotor reactances, rated KV, rated MVA, power factor, number of poles, and system frequency (reactance adjustment is based on RPM for ANSI). Synchronous motor data are identical to the above, but they may include in addition zero sequence reactances and possible resonant shunt data. Although the same, motor data may not be directly importable because of minor differences like horsepower (ANSI) versus megawatts (IEC), poles (IEC) versus revolutions per minute (ANSI), $X''d$ (ANSI) versus ratio of load to locked rotor current (IEC), etc.

IX. Conclusions

This paper, by outlining the salient conceptual and computational differences between the two guidelines, focused on the main mechanisms governing short-circuit calculations. One should always be mindful of these mechanisms when analyzing a particular system. The conclusions can be encapsulated as follows:

- Database requirements for both ANSI and IEC are essentially the same for typical industrial systems. There will be cases, however, that strict adherence to IEC guidelines will require data that is not readily available in ANSI-oriented fault databases and will require access to software with special features.
- The numerical simulations indicated that for all duty types, differences are to be expected when applying the two guidelines. These differences were analyzed and seen to be directly linked to network modeling, rotating equipment modeling, and computational procedures.
- IEC guidelines were found to exhibit a trend for yielding higher estimates for initial symmetrical and peak fault currents. The same trend was also observed in interrupting fault currents for clearing times less than 0.05 s.
- AC decay modeling is quite different in the two guidelines from a conceptual and computational point of view. ANSI favors universal reactance adjustment irrespective of fault location and parting time. IEC favors taking into account machine type, proximity to the fault, and contact parting time. This was found to be a significant factor governing interrupting current calculations.
- AC decay was found to be computationally costlier for IEC by virtue of the clauses providing for machine proximity to the fault, which is a complexity that is not present in ANSI simulations.
- DC decay and peak current computations are quite different in the two guidelines. ANSI favors a single X/R ratio, whereas IEC, in general, does not.
- DC decay modeling was found, in general, to be costlier for IEC by virtue of the clauses providing for more than one X/R ratio, despite the fact that ANSI requires two matrix triangularizations per duty type to obtain the sought X/R ratio(s) at the fault point.
- Steady-state fault current computation procedures are conceptually and computationally different in the two guidelines. IEC requires, in general, generator excitation system response modeling while ANSI does not.
- IEC steady-state fault current calculations were found to be more computationally intensive by virtue of the clauses providing for excitation system modeling.
- Computer simulations performed with both guidelines suggest that adherence to either guideline from beginning to end is essential for consistent results. Furthermore, quantities needed by either guideline are not necessarily computable by the other. Therefore, using results calculated according to either guideline to estimate quantities needed by the other can lead to significant simulation errors.

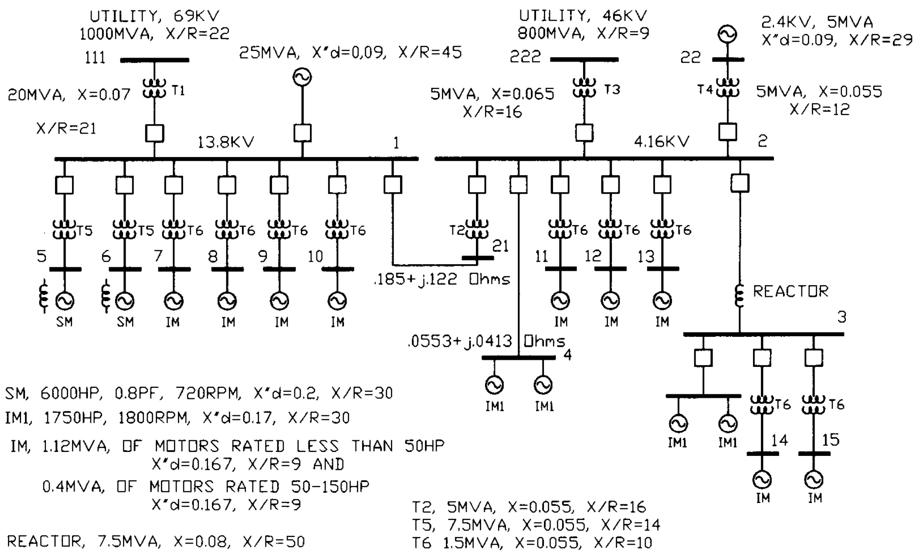

Fig. 1. One-line diagram and data of the sample network.

APPENDIX A
IEC 909 AC DECAY MODELING

When calculating symmetrical breaking currents, IEC 909 recommends the following:

1) The generator current for a fault at its terminals is as follows

$$Ibg(t) = \mu(t) Ik''g \tag{1}$$

where

$Ik''g$ Generator contribution (Initial)
$\mu(t)$ Decrement factor defined as:
$\mu(t) = 0.84 + 0.26\ e^{-0.26\ Ik''g/Irg},\ t = 0.02$ s
$\mu(t) = 0.71 + 0.51\ e^{-0.30\ Ik''g/Irg},\ t = 0.05$ s
$\mu(t) = 0.62 + 0.72\ e^{-0.32\ Ik''g/Irg},\ t = 0.10$ s
$\mu(t) = 0.56 + 0.94\ e^{-0.38\ Ik''g/Irg},\ t = 0.25$ s

where Irg is the rated current. If $Ik''g/Irg > 9$, then $Ik''g/Irg = 9$ and if $I''kg/Irg < 2$ (far from generation), then $\mu(t) = 1.00$.

2) For induction motors, the following expression is used:

$$Ibm(t) = \mu(t) q(t) Ik''m \tag{2}$$

where

$Ik''m$ initial motor contribution
$\mu(t)$ as above but using $I''km$, Irm instead
$q(t)$ motor decrement factor defined as
$q(t) = 1.03 + 0.12 \ln(\mathrm{m}),\ t = 0.02$ s
$q(t) = 0.79 + 0.12 \ln(\mathrm{m}),\ t = 0.05$ s
$q(t) = 0.57 + 0.12 \ln(\mathrm{m}),\ t = 0.10$ s
$q(t) = 0.26 + 0.10 \ln(\mathrm{m}),\ t = 0.25$ s

where m is the MW/pole pair of the motor.

The above equations were used to obtain the equivalent multiplying factors shown in Table IX of this paper. Extending these notions to nonterminal faults entails taking into account the voltage depression at the machine terminals during fault, thus quantifying its proximity to the short circuit [5].

APPENDIX B

Fig. 1 shows the one-line diagram and the data of the sample network.

REFERENCES

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Anthony J. Rodolakis (M'87) was born in Athens, Greece. He received the diploma of electrical engineering from the National Technical University of Athens (Metsovion) in 1977. He continued his studies at McGill University, Montreal, Canada, where he received the Master and Ph.D. degrees in electrical engineering in 1980 and 1985 respectively.

In 1985, he joined the Institute of Research of Hydro Quebec (IREQ), where he worked as a researcher in the Division of Electrical Equipment. Since 1986, he has been with CYME International Inc, where he currently holds the position of senior engineer, and he is responsible for developing commercial-grade power system analysis software for utility and industrial systems. His professional interests focus on the area of digital simulation techniques in power system modeling and analysis.

Dr. Rodolakis is an active member of several IEEE committees and task forces including, among others, the IEEE Brown and Violet book working groups. He is a registered engineer in the province of Quebec and a member of the Chamber of Professional Engineers of Greece.