Fault Contribution of Grid-Connected Inverters

Dave Turcotte, *Member, IEEE*, and Farid Katiraei, *Senior Member, IEEE*

***Abstract*— The distribution grid is mainly built on a radial configuration where power is coming from one transformer substation to supply clients. Up to recently, in the rare cases where distributed generation existed, it was almost exclusively constituted of rotating machines, which have quite a different behaviour under fault than inverter-based sources. Consequently, current connection impact assessments rules were built on years of rotating machines experience and often misrepresent inverter-based sources.**

This paper presents an overview of the issue of short-circuit contribution with respect to distributed generation and highlights the distinctions between rotating and inverter-based sources in this regard. A typical inverter and synchronous machine short-circuit current model is presented as well as simulation results for a 7.5 MW implementation on a typical Canadian network.

***Index Terms*— short-circuit, fault, inverter, distributed generation, DG, interconnection.**

I. Introduction

INTERconnection of distributed generation (DG) is regulated by a comprehensive set of parameters to ensure proper power quality and stability of the grid. While small and isolated independent power producers can connect quite easily, medium to large penetration projects on a single distribution feeder are subjected to more scrutiny. Amongst the interconnection barriers is the DG potential to increase the fault current level of distribution substation or primary networks beyond the permissible short-circuit capacity of substation/feeder equipment.

Up to recently, the grid was exclusively built with rotating machines that have quite a different behaviour under fault than inverter-based sources. Consequently, current connection impact assessments (CIA) often misrepresent inverters due to lack of experience or knowledge of these sources.

This paper highlights the distinctions between rotating and inverter-based sources with respect to their fault current contribution. A typical inverter short-circuit current model will be presented as well as simulation results for a 7.5 MW DG connection study on a typical Canadian network.

II. Short-Circuit and Distributed Generation

Historically, power in electrical grid was flowing from centralized power generation plants to distributed load centers. Power flowing in a single direction allowed for unpolarized (non-directional) protection schemes based on this assumption. DG is shuffling the cards by adding generation points in distribution grids, reducing the visibility of the load and in some cases, forcing power to flow upstream. This change has various implications, one of which being that this new generation is contributing to faults occurring on the distribution grid or in transformer substation. While the fault current will always be increased by adding generation, the consequences on the fault clearing elements can be in two opposite directions:

- If a fault occurs upstream of the fault clearing device (i.e. toward the substation), the clearing device will see the current flowing upstream to contribute to the fault. This is not totally new since even motors will behave as generators, except with less capacity.
- If a fault occurs downstream of the fault detection and clearing device, the fault current seen by the clearing device will be reduced and may even be shadowed by the contribution of the local generation and thus remain undetected. The fault current will still be increased though.

This paper addresses protection issues of DG interconnection in terms of total fault current contribution and changes in short-circuit capacity requirements of circuit breakers or under-load disconnecting switches only. In this regard, all equipment have a limit with respect to the amount of energy they can dissipate. Wires, the building block of distribution lines, transformers, rotating machines are mainly limited in terms of the maximum temperature they can reach before isolation get damaged or material melts. Fortunately, the thermal mass of wires is significant and provides an important grace period before an abrupt current rises causes overheating. For instance, a linnet conductor (ACSR, 336 kcmil) is rated at 510 A but can withstand 40,000 A for half a second before reaching its melting point[1].

Semiconductor devices are also limited in terms of temperature at the junction but the thermal mass is very low and must rely on their conductance with an external thermal pool. The thermal resistance between the junction and the thermal pool is the key factor limiting power dissipation, even for short periods of time. Moreover, the internal connections in a semiconductor device consists of tiny wires that limit the maximum current of the device. In this regard, semiconductor devices are very sensitive to overcurrent but fortunately, they can be turned off very quickly to re-route excess current before the junction temperature becomes critical.

For a breaker, two cases must be distinguised. A closed breaker, that behave like any other conductor, and an opening breaker. A breaker opening on a faulted circuit is exposed to the liberation of an enormous amount of energy. Neither before nor after the fault the breaker operation should be significantly affected by the fault current or distinguishing arc. The breaker is there to open the circuit before other components reach a damaging temperature level.

Consequently, to be free of any concern, the fault current must remain present until the opening of the protection device

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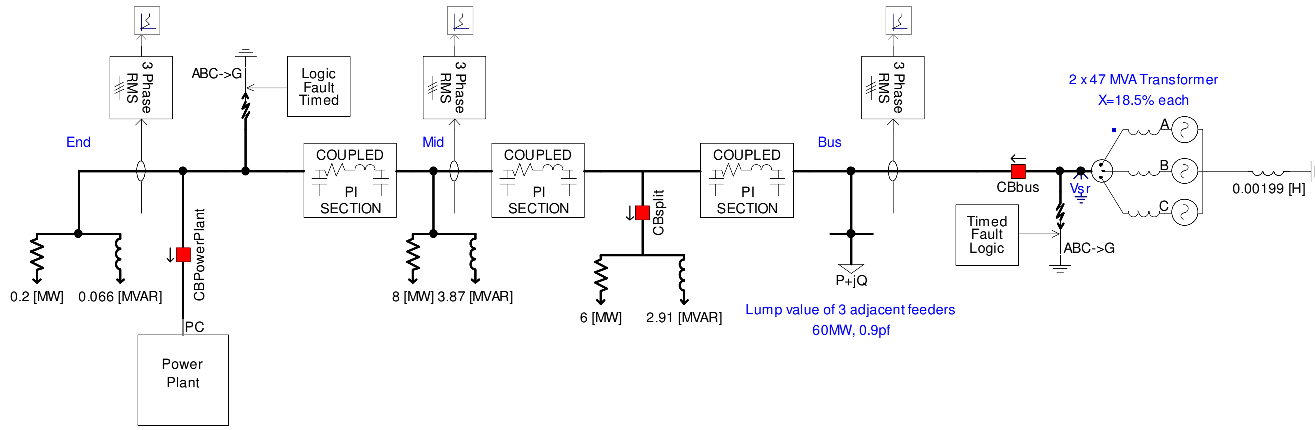

Fig. 1. PSCAD model of the study system

in charge of fault clearing. Typical minimal operating time for a distribution breaker is 3, 5 or 8 cycles. Consequently, a DG source capable of tripping within 50 ms would have no effective contribution to the short-circuit capacity of a system.

III. Modeling

In order to accurately assess the impact of the short circuit contribution of inverters, a PSCAD model of a typical distribution grid was developed as well as the model of a large-scale inverter-based photovoltaic plant. For the sake of comparison, the same work was done with a synchronous generator model representing a small hydro plant. The following sections explain the various models implementations.

A. Distribution Grid

Figure 1 shows the distribution grid used for this study. It represents a typical feeder used in Ontario-Canada, for which the short circuit contribution would be considered already too high. The transmission line is supplied by a substation of two 47 MVA transformers with an impedance of 18.5% each. The 27.6 kV line spans over 25 kilometres with a total load around 15 MW. Adjacent feeders load (about 60 MW) are lumped as a single load. The model is built for two fault scenarios i.e. a three-phase to ground fault at the transformer station or a similar fault type at the line end. The DG plant is located also at the feeder end.

B. Inverter

There are various ways to implement large inverters. HVDC inverters are usually built around 6- or 12-pulse line-frequency converters. On the other hand, modern low voltage inverters are usually voltage source converters using pulse-width modulation (PWM). In all cases, the inverter bridge must be followed by a filter to take out harmonic distortion and allow a controllable power flow.

PWM inverters can quickly cease delivering power to the grid by stopping gating the power devices. With switching frequencies of a few kilohertz, this provides tens of opportunities for disconnection in a single cycle. When dealing with short circuits, the two decision-making mechanisms for disconnection are under-voltage and over-current measurements. Table I summarizes the functions related to these two quantities in a typical inverter.

An important consideration with inverters is the presence of an instantaneous over current relay (function 50). Solid-state devices being acutely sensitive to over current (See section II), manufacturers must equip their converters with fast over current sensors to avoid the power bridge to self destruct at the first abnormal situation.

Figure 2 shows the PSCAD core model of the photovoltaic inverters used for this study. It is essentially an average representation of an inverter using a controllable voltage source (V) with a small resistance representing the resistance of the source (equivalent to switching and conduction losses). It is followed by a breaker (GATES) that is used to simulate the gating status of the converter. Together the source and the breaker represent the converter bridge while not modelling the switching per se. The bridge is followed by a LC filter and a tie breaker (BRK) that controls the connection of the inverter to the grid.

TABLE I
Typical Trip Levels

Fn [2]	Description	Setting	Time (ms)
27	Undervoltage	88%	500
27HS	Undervoltage	50%	30
50	Inst. Over Current	125%	5
51	Over Current	115%	100

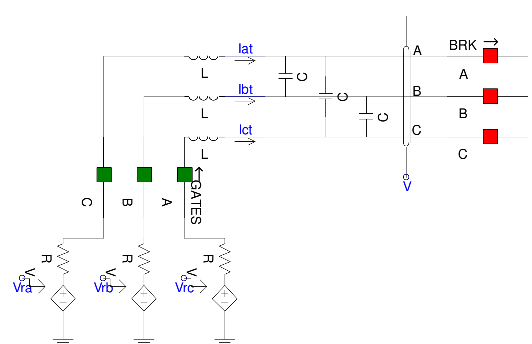

Fig. 2. PSCAD Utility Interconnected Inverter Model

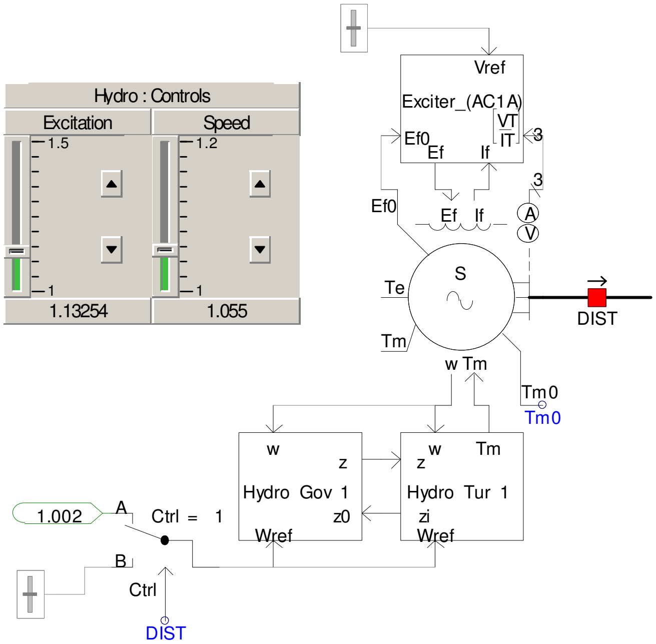

Fig. 3. Synchronous Generator

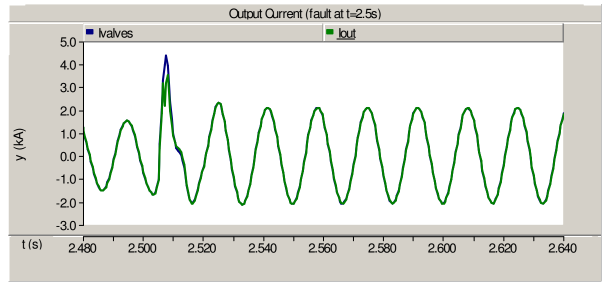

Fig. 4. Fault at the Substation – PV Output Current

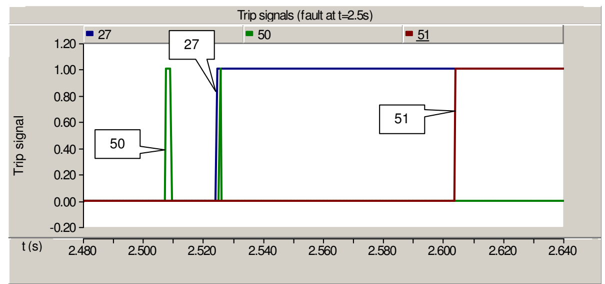

Fig. 5. Fault at the Substation – PV Protection Tripping Signals

C. Rotating Machine

For the sake of comparison, a simulation model of a rotating machine based DG unit is also developed for the study. The model represents a small 7.5 MW hydro DG based on a synchronous generator. The resulting PSCAD model is shown in Figure 3.

The model uses standard components from the PSCAD library. The synchronous generator is excited by the IEEE type AC1A exciter [3]. The governor is based on a mechanical-hydraulic transfer function. Multi-mass representation and/or shaft torsional dynamics are neglected in this model since the generator is small and sub-synchronous resonances are not of interest for this study. A tie-breaker is installed at connection point of DG and used to disconnects the unit. Protections of the tie-breaker operate based on an inverse-time over current relay (function 51) for a fault at the PCC or along the feeder. The relay is set at 250A and uses the extremely inverse characteristic of IEEE C37.112-1996 [4].

IV. Fault Study

For the purpose of this paper, a fault is simulated at the transformer station or at the line end. Current is measured at three locations: at the fault (I_{Fault}), at the generation plant (I_{Gen}) and at the bus breaker (I_{Bus}). The measurements are done with no distributed generation, with a 7.5 MW photovoltaic plant and with a 7.5 MW hydro plant. In all cases, the plant is located at the line end i.e. 25 km from the substation.

A. Fault at the Substation

The first fault scenario investigated is a fault at the transformer station, upstream of the main feeder breaker (the bus breaker in the model). Figure 6 shows the short circuit current without any generation. Obviously the current in the bus breaker decreases by interruption of the supply side. The system load is also represented by constant impedance models that have no contribution to the fault. Although the fault current reaches about 16.8 kA at 50 ms subsequent to the fault, the fault current flowing through the bus breaker is only about 0.45 kA.

Figures 7 and 8 show similar graphs for the cases of connecting a photovoltaic (PV) or a hydro generation plant to the feeder that delivers 7.5 MW of active power at unity power factor. The hydro plant exhibits a 0.64 kA of fault current at 50 ms and opens about 280 ms after the fault. On the other hand, the PV generation is already disconnected at 50 ms.

As shown in Fig. 8 the bus current is slightly increased due to the presence of the hydro generation plant, 0.69 versus 0.45 kA. However, the fault current follows a trend similar to that of the first case (no DG), 17.2 versus 16.8 kA. From these results, it can be concluded that presence of a 7.5 MW generation unit at the end of a line has marginal impact on a fault at the substation and almost no impact if it is a PV generation facility.

The simulation results also shows that the first signal that initiated tripping of the PV plant was the instantaneous over current protection of the PV inverter. Figure 4 shows a close-up of the output current with all the safety features disabled. I_{valves} is measured just before the capacitor bank while I_{out} is measure just after. The peak current observed subsequent to the fault occurrence is essentially due to discharging of the inverter output capacitors (the filters). Figure 4 also shows that even if the inverter would continue to feed the fault, it would be at a level around 1.4 times rated current of the unit. This level is manufacturers specific and may varies in the range of 1.1 to 1.5 times rated current of the unit.

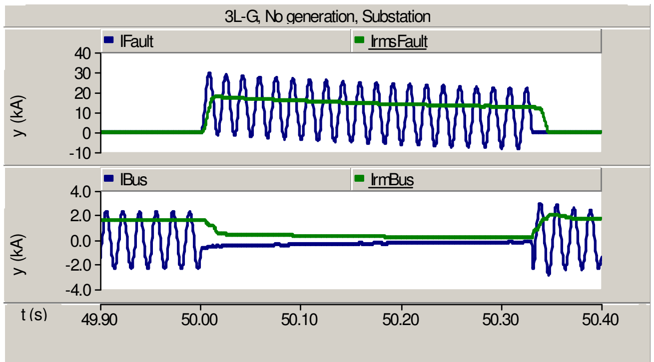

Fig. 6. Fault at the Substation – No generation

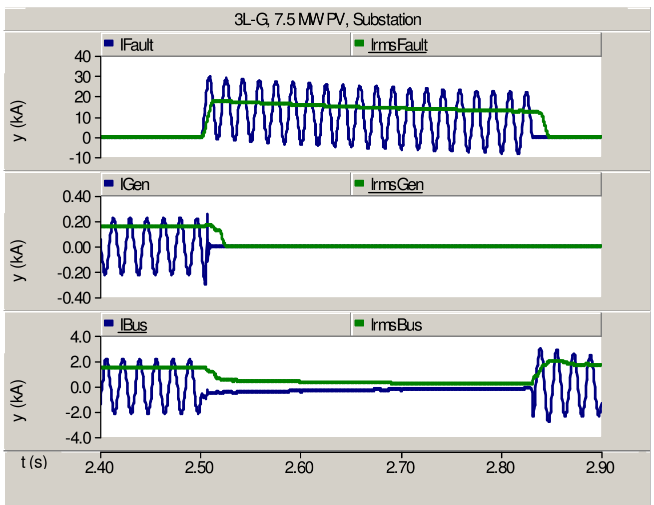

Fig. 7. Fault at the Substation – PV Generation

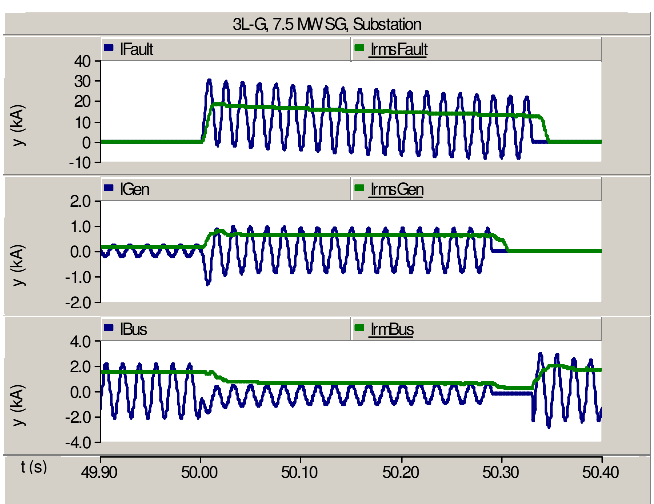

Fig. 8. Fault at the Substation – Hydro generation

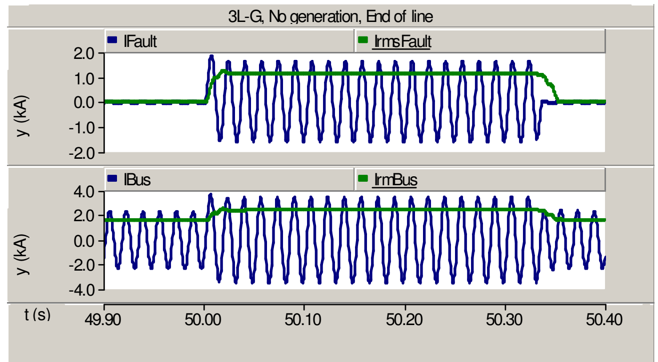

Fig. 9. Fault at the End of Line – No Generation

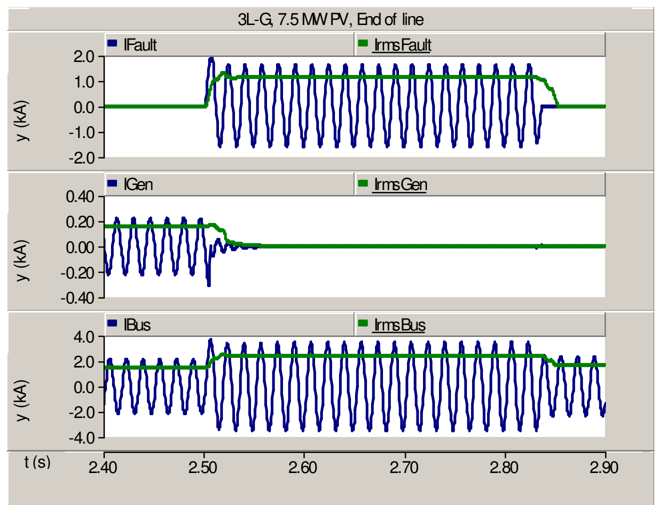

Fig. 10. Fault at the End of Line – PV Generation

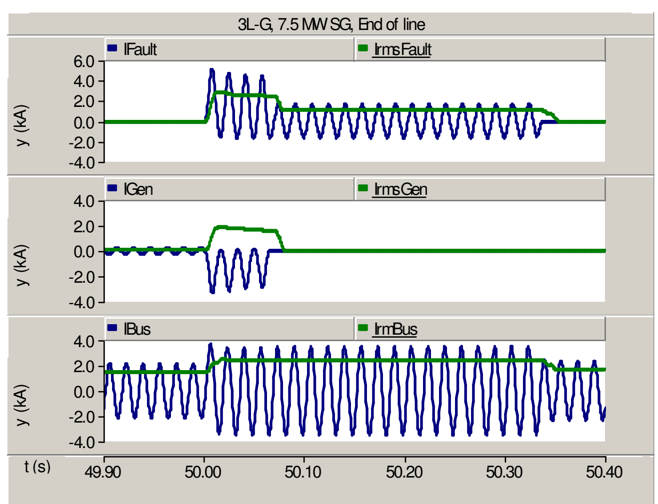

Fig. 11. Fault at the End of Line – Hydro Generation

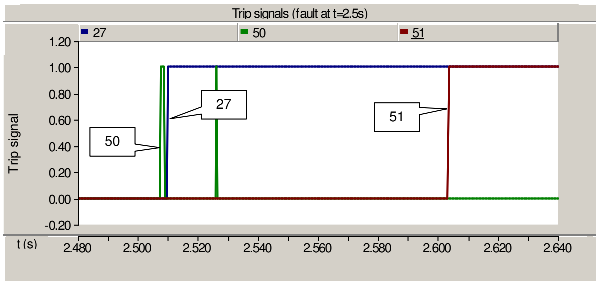

Fig. 12. Fault at the End of Line – PV Trip Signals

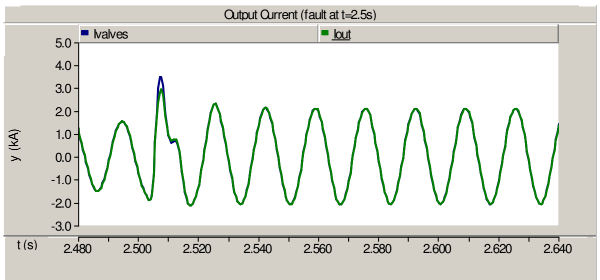

Fig. 13. Fault at the End of Line – PV Output Current

Figure 5 on the other hand shows the sequence of tripping signals generated by the protection devices with their actions disabled. An action is triggered on the rising edge. The signal sequence is function 50 at $t + 7.5$ ms, function 27 at $t + 24$ ms and function 51 at $t + 103$ ms. It is worth noticing that even if the instantaneous overcurrent detection fails, the low voltage detection is still within 50 ms and thus would provide protection to the breaker.

B. Fault at the End of Line

The second fault scenario investigates the presence of a fault at the end of line. Figure 9 shows the short circuit current without any generation. Contrary to the first scenario, an increase in bus current is definitely observed. Fault current at the bus is of 2.44 kA at 50 ms while the current at the fault reaches 1.13 kA.

Figure 10 and 11 show similar graphs but considering the presence of photovoltaic (PV) or hydro generation plant delivering 7.5 MW and zero reactive power. The hydro plant delivers 1.66 kA of fault current at 50 ms and opens about 25 ms later. Assuming contribution to the substation equipment, a slower response of the bus breaker to this fault would actually be beneficial. This approach is proposed in [5] as a general measure to reduce breakers duty.

As for the PV plant, again it is already disconnected at 50 ms, confirming no contribution to the fault. It is worth noticing that in all cases the fault current flow through the main feeder breaker (I_{Bus}) remains the same at about 2.44 kA. From these results, it can be concluded that presence of a 7.5 MW generation unit at the end of a line has no impact on the fault duty of a bus (feeder) breaker.

Again, the tripping sequence was simulated with trip actions disabled (see Figure 13). The obtained results are: function 50 at $t + 7.4$ ms, function 27 at $t + 9.7$ ms and function 51 at $t + 103$ ms. Low voltage detection is significantly faster since the fault occurs close to the plant and thus causes a significantly larger voltage drop. Instantaneous overcurrent is still the first parameter to cause tripping. Figure 13 presents the current evolution of the PV plant with safety features disabled.

V. Conclusion

This paper quantifies the fault contribution of a distributed generation plant installed at the end of a long rural feeder. The primary conclusion of the presented studies is that inverters are capable of stopping delivery of power within the first cycle or few cycles subsequent to a fault. The fast disconnection of inverter-based DG units is achieved on the basis of utilizing very sensitive and highly precise instantaneous over-current protection schemes (function 50) supported by under-voltage detection scheme (function 27). Not only they are capable of doing it but also they are constructed to do so in order to survive disruptive switching events and fault disturbances occurring on the grid. As a result, the short-circuit contribution of inverter-based DG units are insignificant.

A secondary conclusion of the presented studies is that inverters, even with disabled protective functions, will feed a current in the range of 1.1 to 1.5 times their nominal currents which is significantly lower than the 4 to 10 times fault to nominal current ratio typically caused by rotating machines. For a worst case scenario, the contribution of an inverter will not exceed 1.5 p.u.

The third conclusion of the paper is that while medium size rotating machines are more prone to feed a fault, their impact on the feeder breaker fault duty is limited or non-existent when they are located at the end of a line.

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Dave Turcotte (S'92 – M'97) received his B.A.Sc. degree in Electrical Engineering in December 1996 from Université de Sherbrooke, Quebec Canada. He joined the CanmetENERGY laboratory in Varennes in January 1997 where he has been working on various projects related to photovoltaics and power conversion. His current responsibilities include planning and conducting R&D to investigate the impact of utility-interconnected inverters on the electrical grid in order to ensure the adequacy of current and future standards for distributed generation.

Farid Katiraei (M'01 – SM'09) received the B.Sc. and M.Sc. degrees in electrical engineering from Isfahan University of Technology (Iran) in 1995 and 1998 respectively. He received his Ph.D. degree also in electrical engineering from the University of Toronto (Toronto-Canada) in 2005. He is currently manager for market area system testing at Quanta Technology. His research includes power electronic applications in power systems, distributed energy generation systems, and microgrids.