Feeder Protection Challenges with High Penetration of Inverter Based Distributed Generation

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Abstract— **The increasing proportion of inverter based distributed generation (DG) in the power system may limit the short circuit power available at distribution substations and consequently cause significant troubles for the protection of distribution feeders where DG are connected. In this paper, the current practices of distribution network operators in dealing with higher penetration levels of DG are investigated and evaluated using a realistic 31-node distribution network model with limited short circuit supply. The paper discusses the challenges for the protection system related to the integration of increasingly significant amounts of DG and highlights the need for more sophisticated protection systems.**

Keywords: inverter based distributed generation, feeder protection, medium voltage, distribution network, short circuit power availability

I. Introduction

With the introduction of liberalized markets and the drive towards reduced greenhouse gas emissions, the amount of Distributed Generation (DG) connected to the power system is increasing rapidly. As this global trend approaches high levels of penetration, it will be characterized by a more active distribution system with a flow of power that can no longer be considered unidirectional. This means that the conventional, simple, time-coordinated schemes used for the protection of the distribution feeders will no longer be effective.

Common problems with feeder protection as described in [1-3] include: blinding of protection (namely the failure or delayed operation of protection relays due to reduced fault current seen at the start of the feeder caused by DG fault contribution) and sympathetic tripping (namely mal-tripping of a healthy feeder due to reverse current caused by a fault on an adjacent feeder). While these problems are more evident when the DG considered are synchronous or induction machines, they are less serious when inverter based DG, which have limited contributions to fault currents, are considered [4-5].

Nevertheless, as the proportion of inverter based DG increases in the power system, to meet renewable energy production and environmental targets, even the supply short circuit power available at distribution subsystems will be relatively limited. Hence the protection relays will be more sensitive to the contribution of local generation and more intelligent protection schemes will need to be devised.

This paper studies some practices of distribution network operators in dealing with DG network integration and is organized as follows:

In Section II, the test network system, the overcurrent relay settings and the inverter based DG model used in the studies are presented.

Section III identifies the limitations on the penetration level imposed by distribution network operators requiring the DG to disconnect during faults.

The need to change feeder protection settings and the problems associated with it, in case the DG are expected to have the fault ride through (FRT) capability, are examined in Section IV. The paper concludes with Section V.

II. Test Models

The simulation results presented in this paper were achieved using the Power System Simulator for Engineering tool (PSS/E) by Siemens [6].

A. Test Distribution Network

The test distribution network (seen in Figure 1), used in the simulations, is based on a realistic 31-node distribution grid model provided by CREOS, the electricity network operator in Luxembourg. Its characteristics are given as follows:

- Voltage Level: 20 kV
- Total feeder load: 12 MVA @ 0.98 PF
- Average X/R ratio: 1.38
- Maximum voltage drop from bus 1 (without the DG being connected): 5.32% at bus 30
- Supply short circuit power: 500 MVA, adjusted to 100 MVA when accounting for larger proportion of inverter based DG in the power system
- Supply X/R ratio: 3.84

The DG is connected to the 20 kV distribution network through a 0.69/20 kV step-up transformer. The amount of DG connected is represented as a percentage of total load in the rest of the paper.

The distribution of the load is fairly even between both sides of the DG on the feeder.

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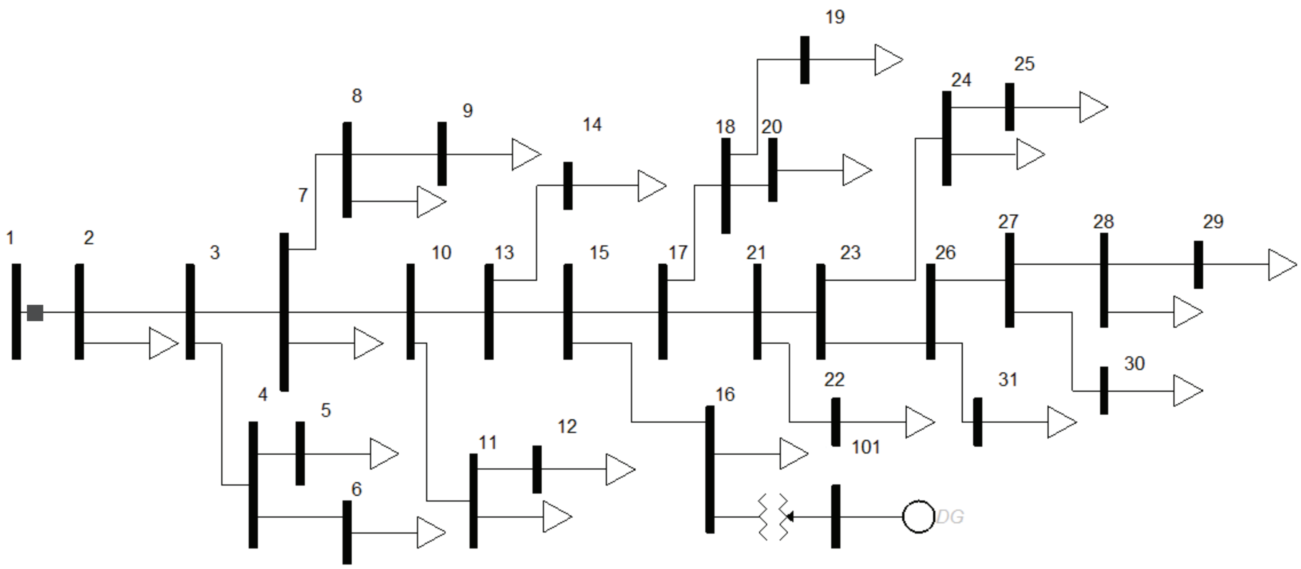

Fig. 1. Test Distribution Network Diagram

B. *Feeder Protection Relay Settings*

The feeder protection relays considered in this paper are inverse time overcurrent relays using the IEEE extremely inverse curves given by [7]:

$$-\left\{\left(\frac{}{(I \quad)}\right) \quad 1217\right\}$$

Where TD is the time dial setting of the relay and is normally used for grading between relays. I_p is the pick-up current and is chosen such that:

$$1.5*\text{Max Load} < I_p < 0.5*\text{Min Short Circuit}$$

Table 1 shows the values of I_p chosen for the test distribution network with supply short circuit powers of 100 and 500 MVA.

TABLE I
PICK-UP CURRENTS FOR RELAYS

Supply SC (MVA)	Max Load (A)	Min SC (A)	I_p (A)
100	380	1200	580
500	380	1720	800

C. *Inverter Based DG Model*

The full power converter wind turbine model used in the simulations consists of the generator and electrical control models, WT4G2 and WT4E2 respectively. These models are available as part of the generic wind turbine model library in PSS/E.

The wind turbine model is an RMS-model based on the positive sequence components and can be used for studies involving symmetrical three-phase faults.

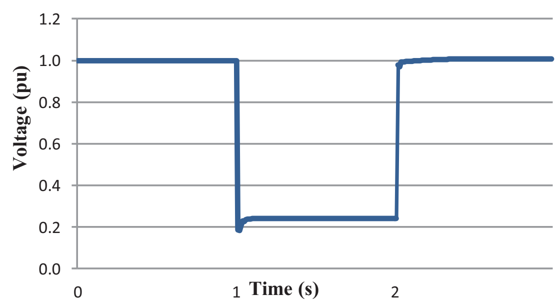

Fig. 2. The voltage response of the inverter based DG model to a short circuit

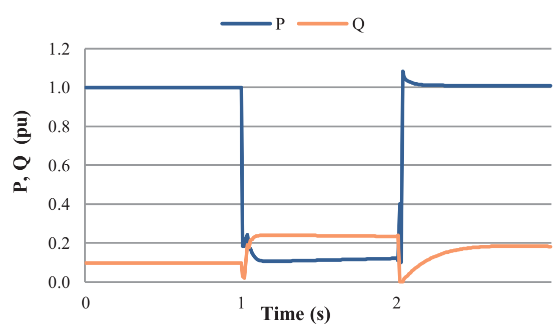

Fig. 3. The P, Q response of the inverter based DG model to a short circuit

The control mode of the converter is set to voltage control at the secondary of the 0.69/20 kV transformer.

The response of the generator to a short circuit between t=1s and t=2s is illustrated in Figures 2 and 3. The contribution of the model to the short circuit current is around 1.1pu and thus considerably smaller than that of synchronous or induction generators.

III. INTEGRATION OF DG WITHOUT FRT CAPABILITY

At the beginning of the DG integration process and especially for small amount of DG power, it has been a common practice for distribution network companies to require the disconnection of the DG during a fault. This is because when the DG disconnect, the system turns into a conventional radial system during faults which allows the feeder protection to work normally.

The main drawback of this approach is that there is temporary loss of generation even when the fault is cleared afterwards (at least until the DG senses that the utility voltage has been stabilized and the feeder re-energized). This is not only a loss of power but also loss of voltage support that can lead to abnormal voltage sags on both medium and low voltage levels, until the on-load tap changer transformer restores the voltage to an acceptable level.

A limit is generally imposed on the percentage voltage change that can be caused by the disconnection of the DG (normally 5%) [8].

Figure 4 shows the impact of varying levels of inverter based DG on the voltage at different buses in the test distribution network. When the DG connected amount to 40% of the total load, the voltage variation is already above 5% at buses 16 and 30 which are nearer to the DG.

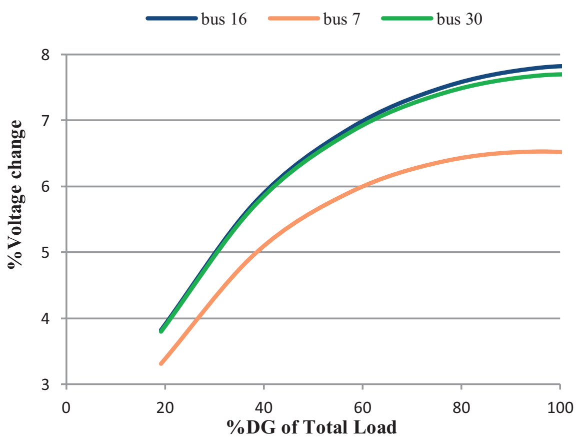

Fig. 4. Percentage Voltage Variation at different Buses due to the Disconnection of Varying Levels of DG

While the disconnection of individual generators making up the 40% would not cause such a variation, in case of a fault, all the generators will be required to disconnect. If the resulting cumulative voltage sag is too high, even after the fault is cleared, the successful restoration of power to the line can be hindered. This imposes a major limitation on the amount of DG that can be connected.

As the trend of power generation increasingly goes towards distributed generation, not accepting to accommodate DG on a particular feeder will become progressively expensive if for example it requires grid reinforcement by installing new lines/transformers. There might also be regulations that require distribution companies to accommodate maximum amount of DG. This means that the use of FRT for DG above a certain size will become necessary.

IV. INTEGRATION OF DG WITH FRT CAPABILITY

If the DG is expected to have FRT capability, its contribution to the fault will affect the operation of the feeder overcurrent protection relay. The extent of the impact depends on the level of its contribution.

The operation control mode of the inverter based DG determines its short circuit contribution, which is typically very limited compared to synchronous or induction machines (only slightly higher than its nominal current). Over the short term, this is positive for the feeder overcurrent protection, because a low contribution means reduced blinding effect (compared to synchronous and induction machines); but over the long term, when the percentage of inverter based DG is higher in the overall power system, this would mean that the short circuit current available from the supply is lower and the feeder protection relays are more sensitive to the limited in-feed current provided by the DG during faults.

Some distribution companies change the feeder overcurrent protection settings in the planning stage to account for the DG fault contribution; this however can cause problems when a sizable amount of the DG is disconnected (e.g. for maintenance purposes).

All these effects are studied in the rest of this section.

A. In the Short Term

To illustrate the short term effect, the system described in Section II is simulated with varying amounts of DG, once considering inverter based DG and another time considering synchronous generators. A supply short circuit of 500 MVA is used.

Figure 5 shows how the ratio of minimum short circuit current to pick-up current decreases with higher amounts of inverter based or synchronous DG.

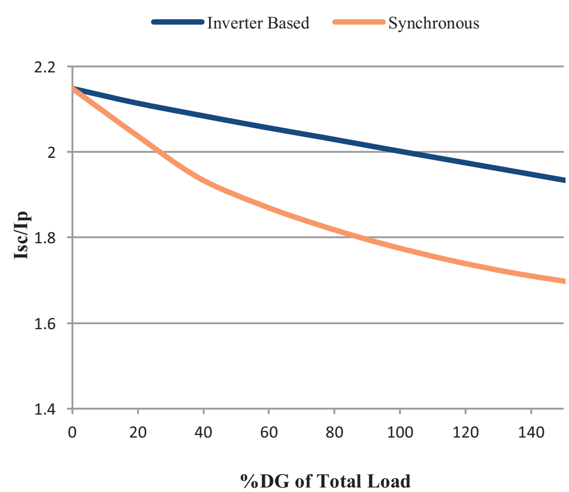

Fig. 5. Effect of Inverter Based and Synchronous DG on Feeder Overcurrent Protection

For a DG connection amount of 60% of the total load, the decrease in the ratio is 4.1% when considering inverter based DG and 12.65% when considering synchronous generators. While no complete blinding effect was observed in either scenario (due to a strong grid connection point), this decrease in the ratio I_{sc}/I_p is equivalent to an increase in tripping time for a relay that uses the IEEE extremely inverse curves (commonly used in distribution networks) of 11.3% and 42.6% for inverter based and synchronous DG respectively. Actual numbers depend on the chosen time dial setting, but taking TD=1, this is equivalent to 130 and 480 ms delay respectively. Any delay in protection operating time is undesirable because it could cause damage to different components connected to the network.

B. In the Long Term

To illustrate the long term effect, the test system is simulated with a supply short circuit of 100 MVA. The results are presented in Table 2.

TABLE II
EFFECT OF INVERTER BASED DG WITH 100 MVA SUPPLY SC

DG (%Load)	$\Delta I_{sc}/I_p$(%)	Δt*(ms)
20	3.01	104
40	5.07	184
60	6.67	252
80	7.99	311
100	9.12	365
150	11.62	497

*for TD=1

Because of the lower supply short circuit, the protection is more sensitive to the inverter based DG fault contribution. For a DG connection amount of 60% of total load, for example, the increase in operating time is up from 130 ms to 252 ms (taking TD=1).

Reducing the supply short circuit level further, would increase this impact. It will thus be impossible to disregard the fault contribution of the inverter based DG.

C. Changing Settings in the Planning Stage

To avoid higher protection operating times, some distribution network operators adjust the relay settings, namely the pick-up current, to account for the DG fault contribution in the planning stage [9-10].

Considering for example the situation where the connected DG amount is 150% of the total load, it is possible to reduce the pick-up current from 580 to 500A to avoid the 497ms operating time delay while still ensuring that there is a sufficient margin to avoid tripping during overloads.

This is a viable solution in the situation where the connection status of the different DG is static or under the control of the distribution network operator. However, this is generally not the case. DG are normally owned and operated privately and their status is not always readily available. As the DG are disconnected from the network, the load current seen by the protection relay increases and the margin planned for overload decreases.

In the extreme case where all the DG in the previous example get gradually disconnected, the margin for overload drops to 30% which could cause mal-tripping of the healthy feeder (e.g. during the start-up of large rotating loads).

In case time coordination is expected between this relay and another relay further down the line or fuses protecting peripheral LV lines, establishing this coordination in the planning stage may also get complicated. To illustrate this effect, a comparison was made between the effect of the DG on the relay at the start of the feeder and another "fictitious" one at the start of the line connecting node 15 to 17. The results are seen in Figure 6 (a strong grid connection point is considered).

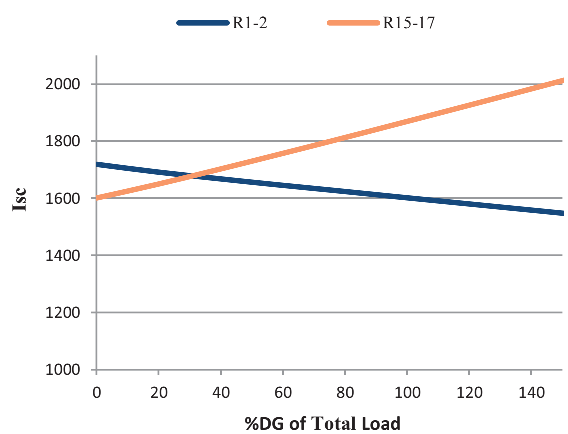

Fig. 6. Effect of Inverter Based DG on Relay Coordination

While the short circuit current seen by relay R1-2 decreases, the short circuit current seen by relay R15-17 increases. Already at a DG amount corresponding to 40% of the total load, the short circuit current seen by relay R15-17 is higher than that seen by relay R1-2. This means that the time and current grading settings needed to ensure that R15-17 operates before R1-2 in case of a fault at the end of the feeder are very different before and after the introduction of the DG. Consequently, if the settings are changed and the DG disconnects during normal operation, the coordination is lost completely.

V. CONCLUSION

This paper shows the impact of increasing amounts of inverter based DG on the protection of distribution feeders. Simulation results are presented to demonstrate the importance of FRT and the challenges associated with adopting it.

Accommodating increasing amounts of DG without changing the overcurrent protection settings could lead to delayed protection operating times and in extreme cases to complete blinding of operation. While the effect of inverter based DG is considerably less than that of synchronous generators, as the percentage of inverter based DG in the power system increases, the short circuit power available

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during faults from the supply will decrease, making the feeder protection more sensitive to even the small contribution of the inverter based DG.

It is possible to change the protection settings in the design stage, hence avoiding the delay in operating time. This however could cause complications when the DG disconnect during operation such as mal-tripping and loss of coordination between different relays or between relays and fuses.

A possible solution to this problem would be to adapt the protection settings of the relays to the changing status of the network automatically. This would require continuous knowledge of the status of the different DG connected to the feeder, preferably using minimal additional measurements. Future research will be carried out in this regard.

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