Distributed Energy Resources and Renewable Energy in Distribution Systems: Protection Considerations and Penetration Levels

Keith Malmedal, P.E.
Member IEEE
Principal Engineer/Project Manager
NEI Electric Power Engineering
Arvada, Colorado 80001
kmalmedal@neiengineering.com

Ben Kroposki, P.E.
Senior Member IEEE
Senior Engineer
National Renewable Energy Laboratory
Golden, CO 80401
Benjamin_kroposki@nrel.gov

P.K. Sen, Ph. D, P.E.,
Senior Member IEEE
Professor of Engineering
Colorado School of Mines
Golden, Colorado 80401
psen@mines.edu

Abstract- **Distributed Energy Resources (DER) including renewables of various designs and ratings have become increasingly common in the last decade. Many States and the Federal government have passed Laws mandating a certain amount of energy be generated using renewables and/or alternative fuels that lend themselves to smaller power plants being connected to the utility system at the distribution level. Power electronics have also made substantial progress allowing inverter-connected smaller power plants with diverse types of fuels to be interconnected with the grid. Optimization of overall electrical system performance at the distribution level is very important for the long-term economic viability of DER systems. It is becoming more important to understand the integration of these systems with the existing electric power system. This paper will address the system integration and utilization issues associated with DER including renewables and will examine protection considerations and penetration limits for DER in the existing distribution systems.**

I. INTRODUCTION

Most assessments of DER applications which describe benefits assume that planning will occur for the optimum locations of these resources. They also often assume that some control over these resources will be exercised by the utility or some other entity [1]. However, due to federal and state legislation the model that may develop is the addition of DER on the existing U.S. distribution systems at locations that have not been previously engineered by distribution engineers and planners for the inclusion of generation. [2].

This model allows or even requires that utilities interconnect small DER on their distribution system wherever the customer happens to be connected. New DER systems will typically be customer sited and installed long after the utility distribution system has been in place. Legislation also seems to favor renewable sources of energy which are non-dispatchable and have low capacity factors [3]. In effect, the utilities will have no choice but to deliver this power whenever and wherever it is available.

The small, low cost, and geographically dispersed nature of these small DER resources will also make any control by the utility difficult and costly. Most legislation, while favoring the DER owner by trying to minimize their interconnection costs, make no provision for funding any utility upgrades which may be necessary for the existing distribution and sub-transmission systems. In the foreseeable future, existing distribution designs will be required to handle any DER connected without major system re-designs. This may not be an issue if DER penetration remains at a small level, but as penetration of DER increases on the distribution system, the significance of impacts will increase. Utilities must develop a methodology to integrate DER and small renewables in the most cost-effective manner. Although there are a wide variety of technical and economic issues when DER is integrated into the distribution system, this paper will focus on protection considerations and penetration levels.

II. TYPICAL DISTRIBUTION SYSTEM

There are a wide variety of distribution systems in the U.S. and the variation becomes even more pronounced when the different types of distribution systems worldwide are considered. However, a vast majority of U.S. systems are radially fed, multiple grounded, and operate at 3-ph, 4-wire 12.47kV [4].

For the purposes of this paper the distribution system shown in Figure 1 will be considered.

978-1-4244-2279-1/08/$25.00

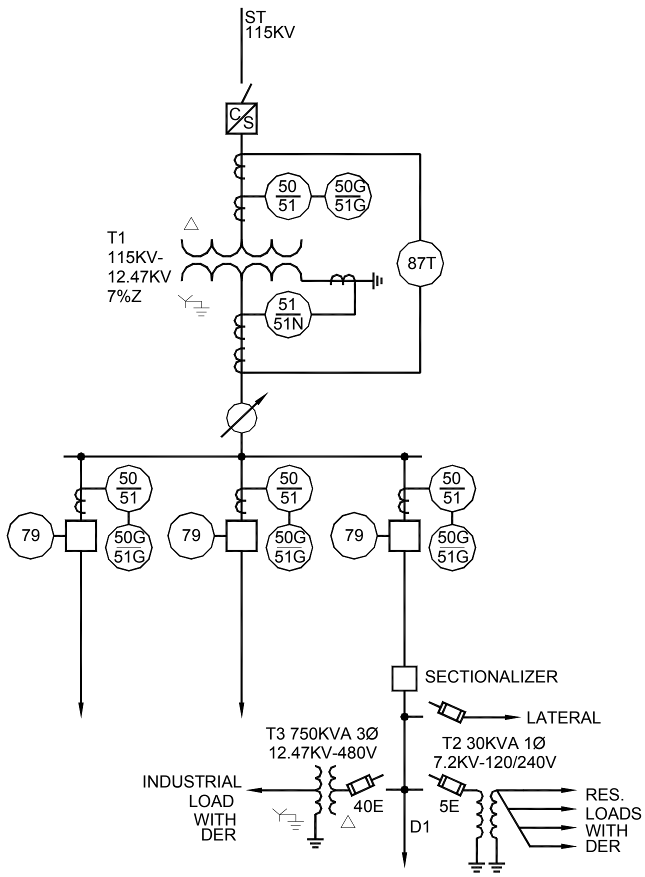

Figure 1. Typical Power Distribution System Including Protection

ST - Subtransmission line: 115kV, 25 miles, 477 kcmil (Hawk), 1-conductor/phase
T1- Substation transformer: 12/16/20MVA, 115kV (Δ)-12.47kV (grounded-wye) with load tap changer or voltage regulator)
D1- Distribution line: 4 miles, 336kcmil (Linnet), 1-conductor/phase
T2- 1-Phase distribution transformer : 30kVA, 7200V-120/240V, Z = 2.5%
T3-3-Phase distribution transformer: 750kVA, 12.37kV (Δ)-480/277V (grounded wye), Z=5%
Fuses: Standard speed overhead fused cutouts.
50/51-Instantaneous and inverse time over current relays
50G/51G-Instantaneous and Inverse time residual ground over current relays
51N-Inverse time neutral over current relay
87T- Transformer Differential Relay
79-Recloser

Figure 1 shows a 25 mile-long 115kV sub-transmission line feeding a substation consisting of a circuit switcher protecting a 12/16/20 MVA, 115kV (delta)-12.47 kV (solidly-grounded wye) transformer. This transformer along with the voltage regulator is feeding three re-closers and their distribution feeders. The distribution feeders consist of typical Rural Utility Service (RUS) wood construction overhead line approximately 4 miles-long using 336 kcmil (Linnet) conductor and each circuit contains at least one line sectionalizer. The typical distribution transformers supplying residential loads are single-phase connected line-to-ground and the secondaries are center-tap grounded (1-ph, 3-wire) and feed 4 residential loads each. The transformers supplying commercial and industrial loads are 3-ph and a 750kVA, 12.47kV (delta) - 480V (grounded-wye) secondary transformer is shown.

It is assumed that both three-phase and phase-to-ground fault currents at the circuit switcher terminals are 15kA. The distribution feeders are loaded to an average value of 50% of their capacities with a peak load of 75% and a load factor of 67%. The substation transformer is loaded to an average of 60% of its maximum capacity (12MVA) and at peak load it delivers 95% of its maximum capacity (19 MVA) with a load factor of 40%.

It is also assumed that all DER is connected at the customer level using some type of power electronics device such as an inverter and are owned by either the residential or commercial/industrial customers. The energy sources on these systems will probably be photovoltaic (PV), small wind machines, low-head hydro or fuel cells. In addition they may also be wind powered doubly-fed induction machines, or synchronous or induction machines using non-renewable sources such as natural gas although there are fewer financial and legislative incentives for the use of non-renewable energy sources in most states.

III. PROTECTION CONSIDERATIONS

When integrating DER into the distribution system there are many important protection issues a utility must consider. Understanding the fault contributions from DER is an important aspect of electrical system protection which impacts the ratings and setting of protective equipment. Typically DER will provide considerably less fault current than the utility through the transformer connection; however the addition DER may increase the amount of available fault current on the system to the point where equipment withstand and interrupting ratings are exceeded.

There is also a considerable difference in the performance under fault between a synchronous or induction machine and an inverter connected source [5]. Most inverter fed sources have little or no inertia [6]. They also can react to limit their output far more quickly than can a conventional rotating machine and typically produce relatively small amounts of current under fault conditions. If other information from the inverter manufacturer is unavailable, a rule of thumb which may be used is to assume an inverter can supply 1 to 2 times its full load current for 1 cycle under a short circuit condition [7][8]. The protective devices in the system which can react this fast are low voltage molded case breakers, low and medium voltage fuses, and instantaneous relays which may pick up but probably cannot open their breakers in less than a cycle.

Synchronous and induction machines with sufficient capacitance on the system (so they can self-excite) can feed a short circuit for several seconds with a reduction in magnitude over time. They are also typically connected to the system using a circuit breaker with an opening time between 3-6 cycles.

If only inverter-connected sources are available on the distribution system, their internal protection can be expected to operate faster than nearly any other device on the system. They will normally disconnect under a fault faster than any other relay or device can operate if they recognize the fault conditions. The contribution to a fault by an inverter fed machine may become an issue if even one synchronous or induction machine is also operating on the system. These rotating machines may support frequency and voltage and allow the inverter connected machines to feed a fault or island condition as long as the synchronous or induction machine remains connected [9].

The first protection issue that must be considered is the interrupting capabilities of various components connected in the system. Any generation (capable of feeding faults) placed on the system may increase the fault duty to all interrupting devices. The components operating closest to their interrupting ratings, in general, are low voltage circuit breakers at the main service disconnect of a residential customer, and distribution fused cut-outs. Although on some systems recloser and substation breaker recloser ratings may also be close enough that they need to be considered whenever a large amount of distributed generation is added.

Figure 2, as an example, shows the part of the distribution system from Figure 1 that feeds four residential loads including the residential service entrance breaker.

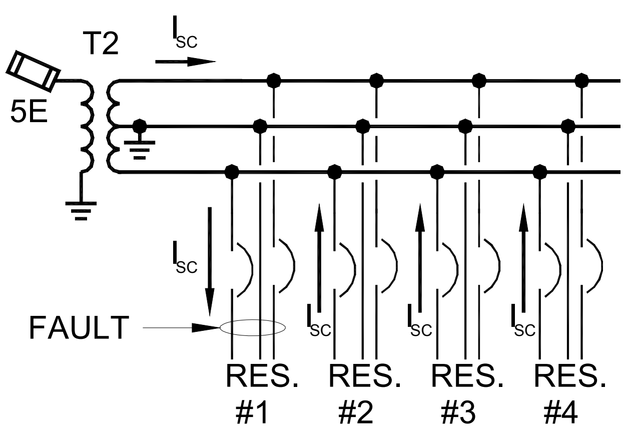

Figure 2. Fault condition with residential DER

If three of the four have DER and a fault occurs at the service of the fourth, short circuit current I_{sc} will flow from the residential DER as shown. A typical interrupting rating for a molded case breaker used in this application is 10kA. Also, metering equipment used in residential construction commonly has a withstand rating of 10kA.

Before the DER was added to this system, the maximum short circuit current available for the fault through the transformer (T2) shown was 4,710A. The largest limiting factor in the system is the impedance of the single-phase transformer T2. If an infinite bus is assumed at the primary of this transformer the available short circuit current would be approximately 5,400 Amps. If the DER used was inverter-based, these sources would have to deliver approximately 5,000 Amps (1,600A per inverter) to exceed the interrupting capacity of the breakers. This would take a total installed capacity of 600kW (or 200kW/inverter) to deliver this amount of short circuit current. This is amount of DER is unlikely in a residential installation. Most residential sized DER will be in the range of 3-30kW which would deliver an additional 25-250 Amps to the system. Therefore, on a typical distribution system it is unlikely that residential, inverter-connected DER will deliver enough short circuit current to substantially increase the risk to adjacent residential interrupting devices no matter how many customers decide to connect DER. A 30kVA transformer is shown, but the same can be concluded for nearly any size of single-phase distribution transformer that is commonly used in the U.S.

To understand fault level contributions at a commercial facility using machine-based DER, we examine a case where DER is added to a transformer feeding two industrial loads. Figure 3 shows the part of the distribution system from Figure 1 that feeds the industrial loads. In this case the main breakers of each of the industrial services may be marginally designed for the original available fault current. In the example shown, if an infinite bus is assumed on the primary side of the transformer, the maximum short circuit current is 18kA. The original design may have specified 24kA interrupting ratings for the main service switchgear. If a typical synchronous generator were added as shown, and it was grounded in such a way that zero sequence impedance of the generator equaled positive sequence, then adding a typical 650kW generator to the system would cause the fault current to increase to 24,016 A which would just exceed the interrupting rating of the switchgear.

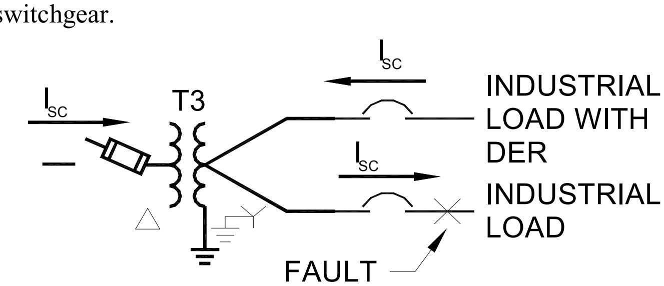

Figure 3. Fault with DER on customer side of transformer

Since conventional (synchronous or induction) machine-based DER can significantly add to available fault current and adversely affect neighboring customers, these DER cannot be added randomly. Whenever a synchronous machine is added, equipment ratings must be examined, not only at the installing facility, but on ever other facility being fed by the distribution transformer.

The effects to system fault current on the medium voltage side of the transformer of adding the DER are reduced considerably when the DER is added on the low-voltage side of the distribution transformer. Consider the case of the fused lateral shown in Figure 1. A fused cutout commonly has an interrupting rating of approximately 12kA. If a fault occurred on this lateral before the addition of DER on the system, the short circuit current could be as much as 5,400 Amps. Depending on the stiffness of the sub-transmission system, this could rise to 7,900 Amps. To exceed the rating of the fuse the DER would have to add a minimum of 4,100 Amps (or 88MVA) of current. A very high penetration level of DER would be necessary for this.

If synchronous or induction machines were added on the low voltage side of the system, the distribution transformer still produces a formidable choke point to short circuit current. It would require the addition of 28MW of typical synchronous or induction machines at the 480V distribution level to increase short circuit duty enough to place the fused cutouts at risk (assuming typical transformer impedances). Any DER added at the medium voltage level, without an intervening distribution transformer, may cause enough additional short circuit current to adversely affect the system, and must be examined more closely. So any synchronous or inductions machines added at the medium voltage level may result in exceeding existing distribution equipment interrupting ratings. Another are if concern, no matter where the DER is added, is that fuse coordination may be affected must be checked.

Another problem with the addition of DER is the possibility of over voltages due to line-to-ground faults. To examine single line-to-ground faults with DER, consider a short circuit on the delta side of any delta-wye transformer which is fed on the wye side by a DER. For example a phase-A-to-ground fault on the delta side terminals of transformer T3 in Figure 1 would be cleared by the protective fuse or by the recloser at the substation. Before the fault cleared the voltages on the three phases would be:

Phase A-Ground = 0V
Phase B-Ground = 1.19 pu
Phase C-Ground =1.19 pu

If the recloser opens to clear the fault, but the DER connected to transformer T3 has not yet tripped, the voltages would become:

Phase A-Ground = 0V
Phase B-Ground = 1.73 pu
Phase C-Ground =1.73 pu

The line-to-ground fault would cause the voltage on the unfaulted phases to rise. This voltage rise will overexcite the other transformers on the system (such as T2) and cause lightning arrestors to operate. At the 1.19 pu over voltage which occurs before the opening of the recloser, these effects are not severe since the recloser would quickly open to clear the fault and remove all voltage to the feeder. However, if after the recloser opens the DER is still feeding the fault the voltage to ground will rise to a level which will quickly destroy transformers and arrestors. Also, since the system is now ungrounded on the delta side of T3, and there is no protective device installed to detect this condition, the over voltage will continue until another component fails which makes the fault line-line or 3-phase.

To prevent this, a method is needed to sense and quickly trip the DER for a line-to-ground fault on the delta side of the transformer. One method would be to add a grounded wye-broken delta set of potential transformers to the delta side of the transformer and use the zero sequence voltage to pick up a over voltage relay (device 59G) which would trip the DER. This must happen more quickly than the recloser can open or the protective fuse can blow, to prevent the severe over voltages which are possible. This will also require some wiring between the utility owned equipment on the 12.47kV system and the DER on the 480V system. This same condition will exist for a ground fault on the delta side of the substation transformer, and a similar method must be used to trip the DER on the system for a fault on the 115kV line before the 115kV line protection can open the far end of the line. This will require the addition of transformers on the 115kV system and some method of tripping the DER for this fault. No doubt this would incur considerable expense.

IV. PENETRATION LEVELS

Understanding how much DER can be added to a distribution feeder without effecting other equipment will become more important as higher DER penetration levels are reached. Technical, economic, and regulatory factors will influence the penetration level for DER systems. On a technical and economic basis, there may be a certain amount of penetration that will be allowed without requiring additional distribution system costs.

DER penetration levels are dependent on a variety of factors including: load factor, load coincidence, and dispatchablilty of the DER. Penetration levels have been defined in several ways. On a distribution feeder penetration level may be defined in terms of a ratio of DER power to the rating of the distribution peak load.

$$\text{DER Penetration} = \frac{\text{DER rating (kW)}}{\text{Feeder peak load (kW)}} \quad \textbf{(1)}$$

or in terms of the ratio of DER capacity to feeder capacity.

$$\text{DER Penetration} = \frac{\text{DER installed capacity} \times \text{capacity factor}}{\text{Feeder capacity}} \quad \textbf{(2)}$$

One aspect limiting penetration level is the thermal effects of DER on transformer loading, fuse capability, and the thermal ratings of other components in the system. If we use the distribution system shown in Figure 2, an important question is: how much DER can be added before the transformer (T2) is overloaded or the fuse is damaged at peak load?

To answer this question the load factor on the transformer (or other component) must be considered. Load factor is defined as:

$$\text{LoadFactor} = \frac{\text{Average Load(kW)}}{\text{Peak Load(kW)}} \quad \textbf{(3)}$$

If the average load on T2 were 12kW at 0.9 lag and the peak load was 30kVA (27kW) at 0.9 lag, the load factor would be approximately 44%. The transformer would deliver 12kW and 5.8kVAR. At peak times the transformer would deliver 27kW and 13 kVAR. Presently, residential type inverters are designed to operate at unity power factor. So they can supply all the real power being delivered by T2 but would deliver none of the imaginary power. If peak generation happened at the same time peak load occurred then the average power (real and reactive) that could be delivered through the 30kVA transformer would be 13 kVAR coming in from the utility and 27kW going out to the utility. So the DER that could be added to the system under this loading condition would be 27+27 = 54kW (27kW going out through the transformer, 27kW being used before reaching the transformer, and 13kVAR coming in through the transformer). In this case the transformer was delivering an average of 12kW of power before DER, or 105,120kWh/year of energy. The DER could be allowed to deliver 54kW, which at a capacity factor of 15% would be 70,956kWh/year of energy. If we take the following definition of penetration level (slightly different from equations 1 or 2) this would be a penetration level of 67.5%

$$\text{DER Penetration} = \frac{\text{kWh by DER}}{\text{kWh before DER}} \quad \textbf{(4)}$$

$$\frac{70{,}956\,kWh}{105{,}120\,kWh} = 67.5\%$$

If peak generation were to occur during a time of average load then, without overloading the transformer, there would be 5.8kVAR being imported through T2, 12kW being used by the residences, and 29.4kW being exported which would mean the DER could be approximately 41.4kW (29.4 kW and 5.8 kVAR going out of the transformer and 12kW being used before reaching the transformer). This would be a penetration level of approximately 52% (using equation 4). If no power was being used by the residences at the time the DER was producing peak power, then the DER could be only 30kW in size. If the DER connected to T2 were larger than 30kW it could overload the transformer when the usage on the system was below average. This would allow a penetration level of only 37.5%. For all load conditions, the maximum size of DER on a distribution feeder is equal to the rating of the transformer or other component being examined plus the minimum existing load.

Maximum DER size = Component rating + minimum load **(5)**

Also, at times, the power factor at the transformer could be very low, even zero if the real power used just equaled the real power generated, but the utility was still supplying the VARs. This may become important if power factor penalties are being charged to the customer. And will be of consequence to the utility since they must install the infrastructure to deliver VARs but may get no revenue from the sale of Watts.

It may be seen that the allowable penetration level of DER on any component without upgrades is a function of the load factor of the feeder, transformer, or other component, and the capacity factor of the DER type. Capacity factor for any power plant can be defined as:

$$\text{Capacity Factor} = \text{CF} = \frac{\text{Energy generated per year}}{\text{Energy generated if peak output all year}} \quad \textbf{(6)}$$

We will also define the following:

$P_{loadmin}$ = Minimum load (Watts) on the device during peak generation

$P_{genpeak}$ = Peak generation (Watts)

P_{new} = New peak (Watts) on the device after generation is added

Then $P_{new} = P_{genpeak} - P_{loadmin}$ **(7)**

Starting with equation (6):

$$\text{CF} = \frac{\frac{\text{kWh}}{\text{year}} \text{ by DER}}{(P_{genpeak})(\text{hour/year})}$$

$$P_{genpeak} = \frac{\frac{\text{kWh}}{\text{year}} \text{ by DER}}{(\text{CF})(\text{hour/year})}$$

If we assume that the new peak output delivered by the equipment under consideration must exactly equal the new peak (P_{new}) so it won't be overloaded when the DER is added then:

$$\text{Equipment size} = P_{equip} = \frac{\frac{\text{kWh}}{\text{year}} \text{ by DER}}{(\text{CF})(\text{hour/year})} - P_{loadmin}$$

$$\frac{\frac{kWh}{year}\ \text{by DER}}{(CF)(hour/year)} = P_{equip} + P_{loadmin}$$

$$kWh/year \ \text{by DER} = (CF)(hour/year)[P_{equip} + P_{loadmin}]$$

Dividing both sides by $Load_{AVG}$(hour/year) before the addition of DER where load is in kW, results in:

$$\frac{\frac{kWh}{year}\ \text{by DER}}{Load_{avg}(hour/year)} = \frac{(CF)(hour/year)[P_{equip} + P_{loadmin}]}{Load_{avg}(hour/year)}$$

Since, on and annual basis, the left side of the above equation is equivalent to penetration level as defined in equation (4) the following equation results.

$$\text{Penetration Level} = \frac{(CF)(hour/year)[P_{equip} + P_{loadmin}]}{Load_{avg}(hour/year)} \quad \textbf{(8)}$$

If LF= Load Factor as defined in equation (3) then:

$$\text{Penetration Level} = \frac{(CF)[P_{equip} + P_{loadmin}]}{Load_{peak}(LF)} \quad \textbf{(9)}$$

If we make the assumption that the equipment under consideration was originally sized to just deliver the peak load than equation (9) becomes:

$$\text{Penetration Level} = \frac{CF}{LF}\frac{[P_{equip} + P_{loadmin}]}{P_{equip}} \quad \textbf{(10)}$$

The worst case condition as far as the existing equipment was concerned would be when the load was zero at the time when the generation was at its peak. If this were the case then from equation (10):

$$\text{Penetration Level} = \frac{CF}{LF}\frac{[P_{equip} + 0]}{P_{equip}} = \frac{CF}{LF} \quad \textbf{(11)}$$

Equation (11) shows that for the condition where minimum load is zero at the time generation is peak the penetration level as defined in equation (4) is a function of only the capacity factor of the DER and load factor of the equipment before the DER was added.

The best case as far as equipment sizing is concerned would be when $P_{loadmin}$ was at the system peak at the time when generation was also at its peak. This would be the best possible coincidence factor. Assuming the equipment was originally sized for this peak load then equation (10) becomes:

$$\text{Penetration level} = \frac{CF}{LF}\frac{[P_{equip} + P_{equip}]}{P_{equip}} = 2\frac{CF}{LF} \quad \textbf{(12)}$$

Equations (11) and (12) are the two possible extremes and it can be seen that the possible penetration level for DER on any existing device, assuming that device were originally sized to carry the original (before DER) peak load must fall between the results of these two equations.

Figure 4 shows the size transformer, wire, etc. a utility must install to allow 100% of the energy used on a feeder or transformer to be supplied by DER using PV (with a capacity factor of 15% average in the US) as a source. This chart assumes that the component was originally sized just large enough to deliver the peak load, and the power factor is 0.9 lag. This chart is also applicable only to PV generation.

Curve #1 in Figure 4 is for the case where the load is zero when the DER is at its peak. Line #2 is the case where the load is the feeder average load when the DER generation is at its peak, and Line #3 is for the case where the peak generation and loads are coincidental.

For example, if the load factor on a transformer is 0.5 and the peak load is 500kVA, then the utility may need to install a transformer that is 500 * 3 = 1,500kVA to allow the customers on this transformer to generate all their annual energy and still not overload the transformer at peak output assuming the worst case where there is no load at the time of peak generation. Taking the best case where peak load happens coincident with the peak generation the transformer size needed would be 500 * 2.2 = 1100kVA. This same condition is true for cables, fuses, and all other components in the system which must deliver the peak power from the PV DER.

Figure 5 uses equations (10), (11), and (12) to show the amount of energy the customers on a transformer (or other system component) can be offset by on-site PV generation without having to upgrade the transformer (or other component).

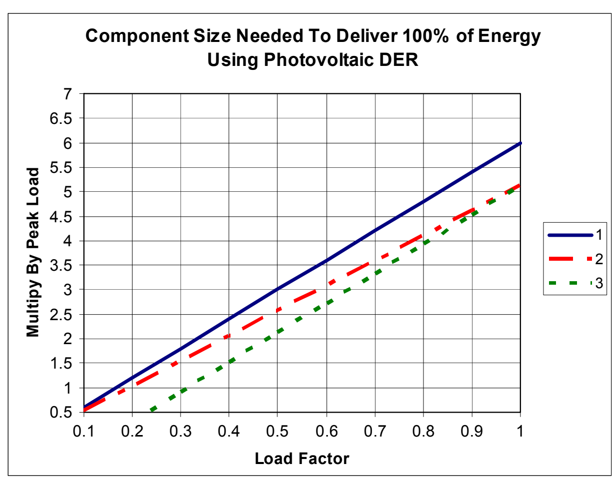

Figure 4. Component size needed to allow delivery of 100% of PV energy

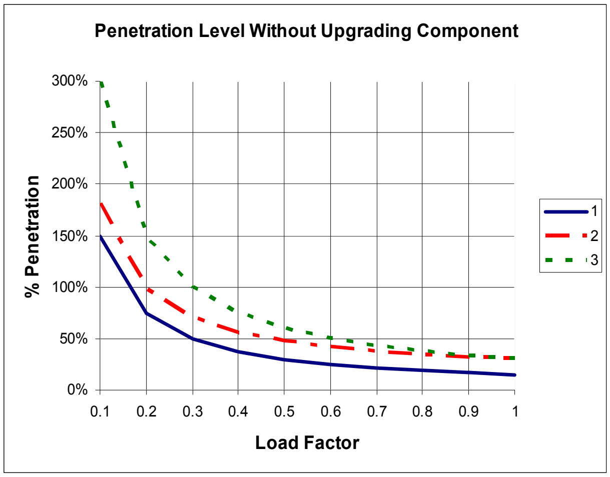

Figure 5. Allowable penetration levels without component upgrade for PV DER

Once again curve #1 in Figure 5 is for the case where the load is zero when the DER is at its peak. Line #2 is the case where the load is the feeder average load when the DER generation is at its peak, and Line #3 is for the case where the peak generation and loads are coincidental.

For example, with a load factor of 0.75, and assuming that the peak load equals the transformer capacity, the customers on this substation transformer could only be allowed to offset 40% of the energy used or the substation transformer and associated protection would have to be upgraded assuming that peak load occurred at the same time peak generation occurred. As used in Figure 5, penetration level is defined as described in Equation (4).

Load coincidence has an effect on penetration level of DER. Consider the two cases shown in Figures 6 and 7. Both of these examples have and average load of 2.5kW, a peak load of 6kW, and a load factor of 0.42. In Case A, there is a good coincidence between the DER production and the load, and in Case B the correlation between generation and load is poor. On an energy basis, this example shows a 100% penetration of DER using Equation 2. If the transformer is rated at the peak load, the transformer rating is not exceeded when exporting power back to the utility in Case A.

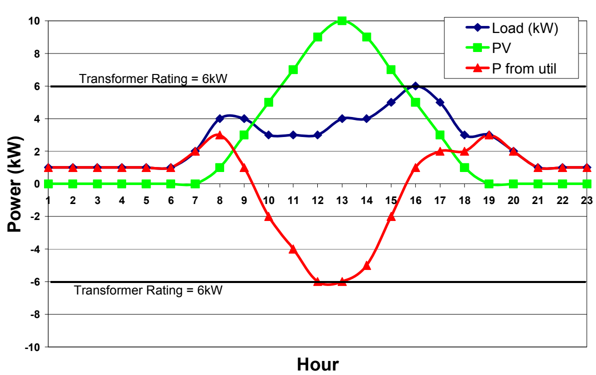

Figure 6. Case A. Good DER Production and Load Coincidence

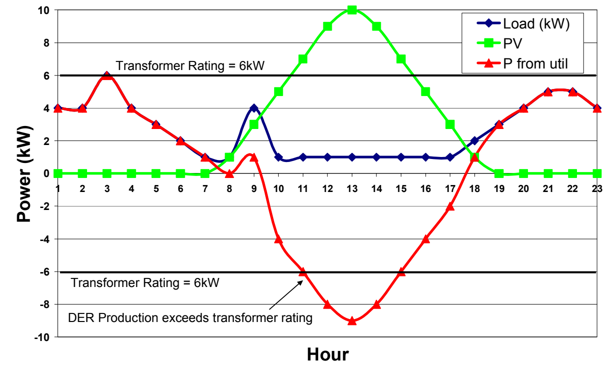

Figure 7. Good DER Production and Load Coincidence

In Case B, there is a period of time where the transformer rating is exceeded.

The penetration levels discussed here concern the maximum levels that would be allowed without upgrading the distribution transformer (or other system component). There may be other considerations such as voltage regulation, cold-load pickup after outages, system stability, protection coordination, etc. that will affect the maximum amount of DER that can be installed without having to upgrade the system equipment.

V. CONCLUSION

This paper has addressed on some of the issues arising from the addition of DER to existing distributions systems dealing with protection concerns and penetration levels. Some conclusions from this work include:

1. Inverter fed residential systems will have little impact on interrupting ratings of equipment but may greatly impact equipment thermal ratings as their penetration level increases.
2. The addition of any synchronous or induction machine on an existing transformer may cause the interrupting ratings of nearby low voltage protective devices to be exceeded and possible effects need to be thoroughly studied before placing it in service.
3. Any DER that can continue to feed a fault on the delta side of a transformer can result in considerable damage to other transformers and lightning arrestors on the system. A method must be added to quickly trip DER for a ground fault on the delta side of a delta-wye transformer being fed by the DER.
4. The maximum penetration of DER on a distribution component is equal to the distribution component rating plus the minimum component load at the time of peak generation.
5. The penetration level that can be accommodated without upgrades due to equipment thermal ratings is a function of the load factor of the device being considered, and the capacity factor of the generation type. Equipment

upgrades may be necessary when as little as 15% of the energy usage on a transformer is being offset by PV systems.

This paper has only examined a few of the issues having to do with protection and penetration levels when DER are added to a distribution system. Future papers will examine subjects such as voltage regulation, reclosing, voltage unbalances, and system stability problems that can be caused by DER added to an existing distribution system.

REFERENCES

[1] C Marnay et al. "*Integrated Assessment of Dispersed Energy Resources Deployment*", Consortium for Electric Reliability Technology Solutions, U.S Department of Energy, June 2000.

[2] Energy Policy Act of 2005, Washington, DC, 2005

[3] K. Malmedal, B. Kroposki, P.K. Sen, "The energy policy act of 2005 and it's impact on distributed generation," *IEEE IAS Magazine*, Jan/Feb 2007.

[4] H. Lee Willis, *Power Distribution Planning Reference Book*, 2nd edition, Marcel Dekker, 2004.

[5] B. Kroposki, et al., "Benefits of power electronic interfaces for distributed energy systems," *2006 IEEE Power Engineering Society Annual Meeting,* Montreal, Canada, June 17-22, 2006.

[6] R. Dugan et al., *Electrical Power Systems Quality*, 2nd edition, McGraw Hill, 2002.

[7] General Electric, *"Reliable, Low Cost Distributed Generator/Utility System Interconnect"*, NREL Technical Report, NREL/SR-560-34634, August 2003, http://www.nrel.gov/docs/fy03osti/34634.pdf

[8] R. Dugan, R. Zavadil, and D. Van Holde, "*Interconnection Guidelines for Distributed Generation*", E-Source, August 2002

[9] B. Kroposki, R. Deblasio, J. Galdo, "Distributed power program DER pilot test at the Nevada test site", *NREL Technical Report*, NREL/TP-560-32063, May 2002

Keith Malmedal (Member IEEE) received his BSEET degree from Metropolitan State College of Denver in 1995, a MSEE degree (Power) and a MSCE degree (Structures) from the University of Colorado at Denver in 1998 and 2002, respectively. He has over fifteen years experience in electrical power design and is presently a principal engineer and project manager at NEI Electric Power Engineering, Arvada, CO, specializing in all aspects of power system design. Mr. Malmedal is a Registered Professional Engineer in 14 states.

Benjamin Kroposki (Sr. Member IEEE) received his BSEE and MSEE from Virginia Tech in 1990 and 1992 respectively. Currently he is a senior supervisor at the National Renewable Energy Laboratory (NREL) and leader of the Distributed Power Systems Integration Section. His expertise is in the design and testing of distributed power systems, and has published more than 30 publications in this area. Mr. Kroposki also participates in the development of distributed power standards and codes for IEEE, the International Electrotechnical Commission (IEC), and the National Electrical Code. He is a registered Prof. Engineer in CO.

Pankaj K. (PK) Sen (Sr. Member IEEE) received his BSEE degree (with honors) from Jadavpur University, Calcutta, India, and the M.Eng. and Ph.D. degrees in electrical engineering from the Technical University of Nova Scotia (Dalhousie University), Halifax, NS, Canada. He is currently a Professor of Engineering and Site Director of the Power Systems Engineering Research Center (PSerc) at Colorado School of Mines in Golden, Colorado. His research interests include application problems in electric machines, power systems, and power engineering education. He has published more than 110 articles in various archival journals and conference proceedings. Dr. Sen is a Registered Professional Engineer in the State of Colorado.