Dakota Electric Comments – DER Technical Requirements 8/9/2018

The following comments from Dakota Electric are addressing the definitions and application of Capacity, non-exporting and excessive energy.

Dakota Electric has found the discussions very educational and informative. We wish there was more time to talk about the issues and ideas involved with the use of the new technology. With the introduction of advanced inverters and with energy storage systems being incorporated into DER systems the complexity of the interconnection continues to grow. Dakota Electric can see how using these two technologies will greatly benefit the operation of the DER system and the interaction with the Area EPS. The use of energy storage with inverter based and non-inverter based distributed generation as the ability to help resolve many operational issues. We appreciate the efforts and input that is being provided by all parties.

Capacity and Non-Exporting

The definition of Nameplate Rating or Nameplate Capacity is the bases for applying the IEEE 1547 standards and many of the engineering screens. So, this definition must utilize the same IEEE 1547 definition for consistency and to avoid confusion. As has been stated many times, the DER manufactures, vendors and installers want consistent standards across the entire region, not a state by state patchwork.

In 2004, energy storage was not economical and not used in conjunction with distributed energy systems. Large UPS battery systems were common place, but they were not designed to export into the distribution grid and were there for outage protection or power quality. So simply using the Nameplate Rating of the distributed generation system worked. Now with energy storage becoming economically viable and given how the energy storage system functions much differently than a traditional generator, it makes sense that we need to add additional definitions to describe how the interface between the DER and the Area EPS is operated.

As part of this process, Dakota Electric is learning about all the exciting operational modes for energy storage, both in conjunction with other types of distributed generation and in standalone installations. The development of technical standards which do not limit the future use of this new technology while maintaining the safe and reliable operation of the electrical system is challenging. Dakota Electric suggests that we look at a sample operational use cases for energy storage and make sure that the initial technical standards work well for those known use cases. If we attempt to incorporate all possible future use cases within this initial technical document, we will be biting off a bit more than is reasonable, given the limited time we have to discuss this very large topic.

The following are some of the initial use cases for energy storage that Dakota Electric believes should be our starting point for the technical standards. First, Dakota Electric sees a use case for standalone energy storage, where consumers install energy storage systems to reduce their demand charges. This would be a non-exporting installation, and this is already being installed across the county and is economically practical. The second use case is the use of energy storage for outage protection and has also been in use for many years and will continue to expand from commercial installations to residential. The third use case is for electrical vehicle charging. All three of these use cases do not involve exporting energy to the Area EPS. The second and the third use cases, are presently designed and installed with a one-way flow of energy; this is to charge the energy storage system and then to use that energy on-site or within the vehicle.

The issues for the utility for these use cases are what is the charging rate, potential for voltage flicker and potential fault current. To support the flow of energy into the energy storage system the utility system must be designed to have sufficient capacity to handle this flow of energy, especially considering the rate of charging. The voltage flicker issue depends greatly upon how the energy storage system is operated. The last issue is with fault current from the inverter, especially for the larger sizes. It would be interesting to talk about just these specific non-exporting installations and see what the utility requirements should be, if the installed energy storage system was limited to this non-export mode of operation.

One of Dakota Electric's concerns is how the energy storage systems, initially installed as non-exporting may be utilized in the future. A consumer installs a solar system, together with an energy storage system and it is studied as a non-exporting system. The interconnection studies and approvals are based upon the non-exporting application. In the future the consumer identifies a potential new use of the system, which involves exporting and they re-apply with the Area EPS for exporting rights. They are then told the transformer needs to be replaced or some other significant utility upgrade cost would be incurred if they wanted to use their system to export. With the process and technical standards that we are developing, is there a way that we can help avoid or at least reduce that surprise?

An interesting example of this concern is as follows; a residential consumer installs a 10kW solar with a 10kW battery system. It is approved for 10kW, as the battery is considered non-exporting. A year later, their neighbor, who is connected to the same distribution transformer, installs a 10kW solar with a 5kW battery. This installation is approved for 15kW. The second neighbor selected a new rate that pays them for generating power during the peak, so their energy storage is considered exporting. We now have a total of 25kW of approved export on that distribution transformer. The second neighbor tells the first person that they are getting a great rate from the utility to use their energy storage system during the peak. So, the first person applies to the utility to use his existing 10kW battery system for the special rate. Here is where the problem occurs. The transformer is a 25kVA rated transformer and with the additional 10kW, the transformer would become overloaded. So, the first person, who installed the system first, is told they must pay thousands of dollars to upgrade the distribution transformer. If we would have initially studied the first installation as a 20kW exporting system (10kW solar + 10kW energy storage), they would have that transformer capacity reserved and the second installation would have then paid for the transformer upgrade. What is the best way to handle this with our standards?

Inadvertent Export

On the topic of Inadvertent Export. Dakota Electric does not fully understand why the levels are being proposed to be so large and so long. With inverter technologies, they should be able to respond quickly to changing conditions and greatly limit the level and duration of inadvertent export. It is the non-inverter connected distributed generation where we have found that inadvertent export is a significant issue. This is because of the nature of the electro-mechanical controls used for a traditional generator. The electro-mechanical controls have a slower response time to changing conditions. Because of this most of these installations transfer the load from the utility when they operate isolated from the utility.

The need to operate isolated from the utility, is due to the faster response time of the protection system as compared to the response time of the generator controls. If the generation system would remain in parallel with the utility, it would be required to trip at the interface for any utility disturbance. When the generation system is operated in parallel with the Area EPS with no-export at the interconnection, it is very difficult for the protection system to tell the difference between a distribution system (Area EPS) problem and a loss of load on the Local EPS which results in inadvertent export. For both conditions there is energy flowing out toward the Area EPS. Since the protection system is set to respond within milli-seconds to a fault, the interconnection opens up for both conditions. So, in the case of extended parallel operation the generation controls are instead set to maintain a small level of energy import, as measured at the interface with the Area EPS. When there is a sudden loss of load, within the Local EPS, from a large motor tripping off line etc., the result is less energy import, but no energy exported. The normal level of energy import creates an operating buffer for the system. Thus, the protection system at the point of common coupling can be set to very quickly trip for any levels of energy export. If inadvertent energy is allowed at the Point of Common Coupling, how would the protection system know the difference between an Area EPS system disturbance and a Local EPS loss of load and be able to quickly respond? The protection system needs to respond in milli-seconds.

Within the technical requirements, we need to be careful of how we define the inadvertent export and the levels which are allowed, especially for the different types of DER. It is important to understand that once we establish a level and duration of inadvertent export which the utilities are required to allow within the technical standards, utilities will not be allowed to reduce that standard level when necessary. But if we set the inadvertent standards tighter, the utility is then still able to allow an increased inadvertent level, if it is safe to do so, for an individual installation.

Transmission Issues with Inadvertent Energy

Another issue that Dakota Electric is learning about, is the potential interaction with inadvertent energy from distributed energy systems interconnected to the distribution system and resultant inadvertent energy at the interface between the transmission and distribution system. Dakota Electric is talking with Great River Energy about potential issues with the distribution system inadvertently back feeding the transmission system. One of the more interesting issues is with back feeding of the transmission system during a transmission fault.

Some of Dakota Electric's distribution substations are connected directly to the transmission lines. Where there is a fault on the transmission line, the transmission protection settings assume that there is no fault contribution from the distribution substation. With the potential for inadvertent energy to flow into the transmission lines from consumer owned DG, especially larger MW size systems, what does that do to the transmission protection? Would we need to consider the distribution substation as a source and have transmission level protection and breakers installed at each of the substations? Many of the substations are protected by fuses, so this would be very expensive. Even if this was done, would this result in more outages to the substations from inadvertent tripping? How would the reclosing be coordinated between the distribution substations and the transmission substations?

At the distribution level, the consumer distributed generation systems, may see low voltage during a transmission disturbance, but their protection system would not be able to see the fault, so they would not trip off line in milli-seconds to eliminate their contribution to the fault? Most likely they would ride-through, using smart inverters. Thus, the distributed generation would contribute inadvertent energy into the Area EPS.

There are a large number of unknowns with how all of these systems will need to work together. As we set the levels and duration for allowed inadvertent energy, Dakota Electric would recommend that we start with tighter levels and allow the utilities to allow larger levels of inadvertent energy as the electrical system in that area allows.