Practical Experience in Commissioning Distributed Generation Installations

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Introduction

Topics Covered

This paper covers the experiences of the authors during commissioning of several distributed generation projects under the auspices of Portland General Electric's Dispatchable Generation Program. This experience covers 18 projects with a total generator nameplate rating of 37.8 MW. One author has been the Engineer of Record on several projects, another is a consultant to the utility and has been involved with all projects discussed, and the third author is a project manager for the utility and has run each of these projects for the Utility.

The material presented includes things we have done that have produced success, and some things we have learned because what we tried did not produce the intended results.

The PGE DSG Program

Portland General Electric's Dispatchable Standby Generation program is designed to make customer-owned standby generation available for dispatch by the utility. The program provides funding to modify customer-owned systems to allow remote control and parallel operation with the utility. In addition to these modifications, the program pays for the ongoing maintenance of the system and the fuel used by the generator; because the utility pays for the fuel, the power from the generator is metered and sold to the customer at the same rate as other utility-supplied power. The program was originally conceived to provide modifications to existing systems but also has been used to partially fund new construction projects.

Types of Customers

Customers in the DSG Program include data processing centers, governmental agencies, educational facilities, high tech manufacturing facilities, hospitals, computer/networking facilities, broadcast transmitters, and lumber mills.

Number and Sizes of Generators

Generators involved in the project ranged in size from less than 600kW to 2.8MW and in voltage from 480V to 12.47kW. Other than a 2.8MW diesel-fired turbine unit, all have been reciprocating diesel engine-driven units. Individual sites have as many as four units, but the most common configuration is a single machine, rated between 1MW and 2MW, and generating at 480V.

Design Issues

Code and Local Inspector Concerns

In several cases, these projects were the first installations local electrical inspectors have seen with generation in parallel with the utility, and the first time the inspector has needed to work with the requirements of Article 705, Interconnected Electric Power Production Sources, of the National Electrical Code.

We have found that inspector concerns generally can be addressed by meeting with the inspector to review the project, explaining step-by-step how the various requirements of NEC705 are being addressed. Utility grade relaying, meeting the requirements of IEEE-1547™, has been sufficient to meet 705.12(B)(3), which requires that "Safeguards and protective equipment are established and maintained."

NEC705.16, Interrupting and Short-Circuit Current Rating, requires a fault study be conducted; for solidly grounded systems it is often found that a generator in parallel with the utility produces significantly higher single phase-to-ground faults than the sum of the two sources independently.

NEC705.30(C), Transformers, can become a difficulty if not addressed early in the process. In most projects this has not been an issue, as the only transformer being fed from both sides is the utility's service transformer. In one project, the generator operates at 4160V and the system distribution voltage is 12.47kV. Per the requirements of NEC705.30(C), which also references NEC450.3, this transformer needed primary and secondary protection on both sides of the transformer, implying a breaker within 25 feet of both sides. Locating these breakers was not practical and would have been quite expensive. The inspector accepted an alternate approach using a differential and overcurrent relay at the transformer, with CTs on both sides of the transformer, and tripping both breakers for any transformer or conductor fault condition found. The Code requirement assumes sensing and interrupting in the same device, while the installation leaves the sensing at the required location and trips further upstream regardless of power flow direction.

NEC705.40, Loss of Primary Service, and NEC705.42, Unbalanced Interconnections, are both satisfied when the requirements of IEEE-1547™ have been met.

On one project with medium voltage switchgear, CTs were to be added at each generator breaker to provide revenue metering of the generator output. An electrician who should have known better raised a concern to the electrical inspector about CTs with 600V insulation being used in medium voltage switchgear around shielded, insulated cable. Because the inspector had little experience with medium voltage installations, it was necessary to provide information from multiple CT manufacturers showing that 600V insulated CTs are designed and listed for use on insulated medium voltage cables. A potential crisis was averted, but it did take some effort to provide the necessary information.

Drawings Should Accurately Reflect What is Installed

This one seems to be a never-ending battle. It starts with as-built drawings that do not accurately reflect existing conditions, to construction drawings that are not followed (and not revised to show as-constructed conditions), to field drawings that do not include all changes, and includes manufacturer's shop drawings that do not accurately show the equipment constructed.

Troubleshooting during commissioning depends on accurate knowledge of connections and how they are intended to operate. When drawings do not match physical reality, the process bogs down.

Sequence of Operations should Include Upset Condition Handling

One of the projects in the program included new gear for a primary service fed from two utility circuits and included the ability to run the generator in parallel with either of the circuits. The project specifications included a detailed sequence of operations for conditions ranging from normal operation with each circuit feeding half the load, to loss of a single utility circuit, to the generator as the sole source of supply, and the generator running in parallel with either utility circuit. There were also descriptions of what to do on loss of either utility circuit under all of the operational conditions and how to make transitions among all of the defined operational modes. What wasn't included were instructions for what the system should do if something went wrong, such as when the generator didn't start or a breaker didn't close when commanded.

During the initial testing, we found that if the generator failed to start, the system did not operate but waited for the sequence to complete, even if a utility circuit became available again. A standard Automatic Transfer Switch would handle these situations without a problem, but when a custom control system is being developed, it is necessary to specify everything desired for system operation. This particular system, while doing everything specified, was very fragile because it depended on all portions responding in the desired manner. It became necessary to write a change order to the project to include a series of "off-nominal" conditions and how the control system should work around them.

Define Forward/Reverse Directions

The definition of "forward" and, therefore, "reverse", current and power flow seems straightforward at first glance, but can mask some problems. The PGE DSG program includes a utility-provided interconnect relay, unless the customer already has protection that meets the program requirements. This relay is installed at the breaker where the generator will be paralleled with the utility during a return to utility following standby operation of the generator. This may or may not be the same breaker used to parallel the generator with the utility while the utility is present.

From a customer standpoint, "forward" would logically be from the utility toward the load. From a utility standpoint, if the relay is being used only while in parallel operation, "forward" could just as well be toward the utility. It was agreed that for the PGE DSG program, “forward” would be toward the *customer* load, and “reverse” toward the *utility* connection.

This worked well until one project with the interconnection point between the generator and the facility. Now, the customer load and the utility were both in the same direction and the definition did not provide clear-cut guidance. “Forward” was selected as being *away* from the generator, and reverse power elements set to protect the generator from motoring. Months later, when it was time for the first attempt at parallel operation of the generator with the utility, it was paralleled at a low power output level. All was fine for a few minutes until a trip on reverse power occurred. Without a definition of “forward” and “reverse” that related the relay to the generator, it was necessary to determine exactly how the CTs were wired to determine that “forward” was away from the generator, and it was a controls problem that caused the reverse power trip.

If “forward” had been defined as flow from the utility, through the interconnect point, toward the generator, this project would have had “forward” and “reverse” defined opposite of what was used, but there would have been a consistent relationship from project to project.

Sync Check Parameters – Gen Controls vs. Relay Sync Check

In many cases, the generator controls provide an auto synchronizer with associated sync check functions, and the interconnection relay provides additional sync check capabilities. It is important to coordinate these so that the relay sync check settings are not more restrictive than the generator controls. If the generator controls allow a larger voltage or phase angle window than the relay, it is possible for the controls to request a breaker close and have that close blocked by the relay. Some packaged generator controls respond to a fail to sync by shutting down the generator. Other generator controls allow multiple attempts to synchronize.

PGE’s DSG program has determined that it is best to set these multiple sync check devices so the *redundant* sync check is set as widely as possible to minimize the chances of a nuisance block of a breaker close. It is also important to discuss the exact sync check parameters that all these devices use prior to commissioning; we have had some interesting discussions about resolving problems in sync checking when one device uses ‘slip frequency’ and another uses a time duration of parameter matching to ensure synchronization.

Protection Philosophy – Is the PLC a Protection Device?

Systems capable of operating a generator in parallel with the utility typically have a controller based on a PLC or similar platform. This PLC is in addition to, and separate from, the logic capabilities of the interconnection relay. In many cases, the PLC will have inputs that provide it with voltage and frequency information about the power system. Should the PLC be allowed to provide protective functions based on the system parameters it has, or should all protective functions be provided by the protective relay? One viewpoint is that PLC is not an essential device and protection is an essential function; therefore, the PLC should not be relied upon for protective functions. On the other hand, not much is gained by tripping the system on a voltage or frequency event if the controller is not functional and cannot start the generator in standby mode to pick up the loads.

In one project, the interconnection relay was planned to provide voltage and frequency protection and to trip the interconnect breaker to protect the load from off-nominal voltage conditions. On the first test of the system, PT fuses were pulled to simulate a power outage, the relay tripped the breaker, and the PLC did nothing. It turned out that the PLC saw the breaker opening as an unexpected event and didn't know what to do at that point. In the case of this particular packaged control and transfer system, the manufacturer would not provide a system warranty unless their controller retained the basic functions with which it left the factory. Resolving the issue at this particular site resulted in the PLC having the voltage and frequency protective functions while the generator was not operating in parallel with the utility. The utility would not allow a device other than the interconnection relay to be the sole source of any protective function while the generator was operating in parallel with the utility, so the relay retained voltage and frequency elements that were active while the generator was paralleled with the utility.

Utility Protection Issues Must Take Precedence Over All Other Issues

On some of the projects, it has been found that the programming of the control system would be easier if it were allowed to respond directly to system problems while the generator is operating in parallel with the utility rather than having to respond to the interconnection relay opening the breaker. The problem here is that the utility maintains control of the programming of the interconnect relay, but it does not have the resources or capability to maintain the PLC program. To maintain assurance that required protective functions remain operational, these functions must be implemented in the relay rather than in the PLC.

Often, the generator controls focus principally on the breaker used to parallel the generator to the utility, but this may not be the breaker considered the point of common coupling under IEEE-1547™; it is the breaker at the point of common coupling where the interconnection relay is installed. The breaker at the point of common coupling is typically the breaker across which the generator will be synchronized and paralleled when the utility has returned following an outage. This is the point at which the utility's protection role is defined and where protection takes precedence over the convenience of the controls vendor. This is also the point at which the IEEE-1547™ protection requirements must be implemented.

Review Vendor Supplied Submittal Drawings and Comment on Prior to Fabrication or Installation

It is very important that submittal drawings be thoroughly reviewed and commented on, and that the comments are fully understood by the vendors. In one project, a paralleling transfer switch was to be provided. From the control and protection provisions, such as the location of the interconnection relay, it became apparent that the drawings had notations for the generator source breaker and the utility source breaker reversed.

When low voltage systems are specified with three VT voltage connections, vendors have a tendency to provide their initial submittal drawings with two VT voltage connections. To help catch this and related issues, the vendors should be required to submit three-line drawings of the gear showing all power, CT, and VT circuiting. Relay elemental diagrams are also very useful in determining whether the vendor understands the project requirements.

Some vendors have very little experience in paralleling to a utility so that it takes multiple discussions to ensure that all parties agree on all the issues in a drawing set.

Construction Issues

Field Changes need to be Correctly Designed and Added to the Drawings

At one site, it was necessary to provide connections between certain outputs and inputs. Written instructions, but no drawings, were issued to connect the listed output at one device to the listed input at another device. When testing showed a failure of the new connections, investigation showed that the output and input were indeed connected, one wire from the output to the input and another wire from the other side of the output to the other side of the input. Without a voltage source, dry contacts don’t create much of a control circuit.

100% Point-To-Point Verification

It is necessary to check all control wiring to ensure that it has been connected correctly. This includes both factory and field wiring. On one project that included new medium voltage switchgear, numerous problems with wiring were encountered. Installation problems forced the switchgear to be shipped as individual sections, so there was a higher than usual number of connections to be made across shipping splits.

When checking circuit connections, it is also necessary to think about the intended use of the wires. On this same project, the factory drawings showed a group of connections to a relay where the terminal numbers on the drawings were one higher number than they should have been. In a group of four wires, the first went to the second terminal of input number one; the second wire, which should have been the other side of the same input, went to the first terminal of the input two; the third wire on the second terminal of the input two; and the fourth wire ended up on the first terminal of a third, otherwise unused, input. The supplier’s field person who was checking the wiring noted that each wire was in the place indicated on the drawings, that it didn’t seem to make sense, but since it was as shown on the drawings, he did nothing. The inputs in question were blocking inputs for a fast bus trip scheme, so the main breakers repeatedly tripped on load side transformer inrush until the problem was found and corrected.

Commissioning Issues

Have a Commissioning Plan

A plan provides a template for conducting the testing. To this point, we have not been able to follow a plan exactly as written, but a written plan provides a means of listing all the operational conditions to be tested. While testing, things go wrong, and the plan becomes a means of keeping track of what has been accomplished and what has not. This is particularly useful when it becomes necessary to conduct tests in a different order than originally anticipated, or if commissioning ends up continuing into other days, weeks, or months.

Have a Commissioning Director

While there may be many people involved with the commissioning who have responsibilities for various aspects, one person needs to be selected to direct the testing. All direction to parties involved should come from this one director. Others may provide input to this director, but with only one person providing direction during the testing, the likelihood of different people working at cross-purposes is minimized. It is also important that no one proceeds from one step to the next without a go-ahead from the director and that all parties involved are ready for each major step of the commissioning process.

Commissioning plan is an idea that we came up with and did not have to learn the hard way; we found early on that it provided significant benefit. At one of the first systems to be commissioned, the commissioning crew consisted of the site facilities personnel, the corporate facilities director, a consulting engineer working for the corporate facilities director, the utility's project team, a utility line crew, a consultant to the utility, the engineer of record for the project, the PLC programmer, the controls contractor, the generator technician, and support personnel for various building systems. Despite having so many people who all had their own ideas of how to proceed when things weren't going as planned, we were able to keep on track by discussing the situation, and then one person making the call as to what to do next. Sometimes that call is a step in the plan, other times it is just to have someone fix something or to revise a program as necessary.

Have PLC Programmer on Site, not a Tech on the Phone to the Programmer

We have found that all projects of this nature require various changes to the programming of the PLC during commissioning. There are timing issues, sequence issues arise and, in many cases, the hardware doesn't work as anticipated. When the PLC programmer has been on-site during commissioning, he generally has been able to analyze the failed operations and correct the program in a timely manner, allowing commissioning to proceed. For other projects, the PLC system provider has sent a technician to the commissioning. When a change was needed, the technician had to call someone at the factory to discuss the issues and wait for suggested programming changes. In one project in which the PLC only controlled two breakers and one generator, the technician spent more time on the phone than in actually running tests. That said, it is also important to ensure that someone from the factory is available as a resource for the field testing if truly necessary. Having the programmer on site becomes a greater concern when the commissioning activity is scheduled overnight.

Robust Communications are Essential

During the commissioning of one site, we needed to have a utility line crew open a pad-mount switch across the road from the site to test standby operation; it is always important to make sure that system changes don't disable essential functions. We provided the line crew with a radio handset and they went out to the switch. Communications were checked, they could hear us clearly, and we could hear them clearly. The request was issued for the line crew to disconnect the power. The power went out as anticipated, but the generators didn't start; after a few moments, it was apparent that they weren't going to start. All attempts to communicate with the line crew on the radio failed; eventually the generators were started under manual control and brought on line to power the building. Once the generators were on line, we were again able to contact the line crew on the radio. It turned out that communications to the line crew were dependent on a repeater; the facility had UPS backup for about half the loads, but the repeater was not included on the UPS. On subsequent tests, we contacted the line crew on a cell phone.

At a different site, we were using the telephone for communications and found that, during some outage conditions, the on-site phone switch would drop out and reset. Calls in progress at that point were dropped and they had to be redialed. We were using the telephone at this site because available radios could not reach from the switchgear, three levels below grade, to the generator on the roof or to the utility crews at the street. For the most recent testing at this site, we used radio, but had to station someone at a central point to relay communications.

Make Sure all Tenants Know What is Going to Happen

One site included several tenants; a representative of each tenant was informed of the planned weekend of commissioning activities, including warnings that there would be numerous power outages. During the weekend, maintenance staff of one of the tenants showed up on site in response to a page that there had been a number of power outages. The maintenance people were never informed of the planned work.

Where Possible, Test all Phase Loss Combinations

This may not be feasible; for instance, when the only point to create an outage is a live front three-phase switch. But when possible, verify proper system response to individual loss of each phase of the utility supply. This usually will require the assistance of the utility, and having the utility as a partner in the project is a definite plus.

In one project, it was found that the controls were sensing only one phase for loss of utility. This was discovered when a utility line crew pulled a different phase fuse than the one sensed, and the controls proceeded to allow the facility to be exposed to a loss of phase event for some time.

Another project had two independent problems found during separate commissioning sessions, both of which caused the system to fail to recognize the loss of a phase. This project had two utility sources, and the generator can be paralleled with either of the two utility sources. The PLC controls a pair of control relays used to switch the voltage used as a reference by the generator synchronizer. Each of the two voltage circuits was to be routed through normally open contacts on the control relays, but they were instead run through normally closed contacts. This connection provided voltage where there should have been none, and the protective relay that should have opened the main breaker did not. After the control relays were rewired, that part of the system seemed to work as intended for the remainder of that commissioning session.

The switchgear included two sets of two CPTs, one set associated with each of the two services. Of each set, one CPT was connected on the utility side of the main breaker and the other on the bus side. During the round of commissioning where the VT crossover through the control relays was found, the station power was coming from the CPTs on the utility side of the main breakers. During the next round of commissioning, the station power was coming from the bus side CPTs.

After having solved the problem with the VT crossover, we discovered that when the utility line crew pulled the Phase A elbow on one of the services, dropping one phase, nothing happened. The utility side CPT, with no load on its secondary, was able to hold the voltage on the missing phase high enough so that the undervoltage element of the relay was not seeing a loss of phase condition. This was subsequently corrected by including a negative sequence overvoltage element in the loss of utility logic. While the phantom phase condition created by the unloaded CPT was producing a voltage over 90% of nominal, it was only a few degrees away from the Phase C voltage, the phase at the other end of the CPT. On a 120V basis, one phase at 110V and 10 degrees away from another phase produces a negative sequence voltage of more than 60 volts. We found that a negative sequence voltage of 10 volts indicates a significant voltage imbalance, due either to magnitude differences or to phase angle problems.

Check Utility Voltages before Initial Paralleling

At one site, we began trying the first parallel operation with the generator controls set to produce 100kW, with no customer load, so all of the generator output would be fed back into the utility. What was seen looked like one of the CTs must have been wired backwards, current out on two phases and in on the third. When two meters and one relay, all with different CTs, were all found to be showing the same thing, we decided it wasn't likely to be a CT wiring problem. When the generator was stopped, the utility voltages on this 480V system were noted as being: A – 277V <0°, B – 284 <-117°, C – 283<119°. At 100kW, it appears that the generator was running about 2° ahead of Phase A, and so 1° ahead of Phase C, but about 1° behind Phase B. This explained the current in on Phase B and why the generator was putting out so much more current on Phase A than on Phase C. When the generator output was increased, the Phase B current turned around and flowed outward with the other two phases, but it was never as high as either of the other two phase currents.

Where Possible Commission before Loads are Connected

The best time for commissioning is when the generator is being connected through new switchgear and there can be a period where the generator and utility are connected to the switchgear but loads are not yet connected.

In one project, we were able to perform several outage tests at a broadcast transmitter facility without any impact to operations, because we were able to have the switchgear connected just to the utility and the generator. Temporary generators provided backup to the existing utility connections as the permanent generator was disconnected from its old ATS distribution and connected to the new paralleling switchgear. Additionally, this allowed us to do much of the commissioning during the day rather than during the early morning hours.

In another project that included new switchgear, schedule pressures had much of the existing building load transferred from the previous utility service to the new switchgear before it was thoroughly commissioned. All of the generator-backed loads were still on a temporary generator at the time of commissioning, but nearly the entire remaining load was transferred before commissioning began. Because of this, commissioning was limited to selected weekends with 15-hour days. If the load transfer had been delayed, the commissioning could have been conducted during the day without impact to the building loads or occupants.

Conclusions

Commissioning of distributed generation projects is an essential component of bringing a system on line. We have not found a system that worked as desired on the first attempt. Commissioning should be planned into the project budget and schedule from the beginning. Good communications, using equipment that is not dependent on the system under test, is an essential part of any successful commissioning effort, and a plan for the commissioning provides a good guideline for keeping the process on track when things are not going as anticipated.

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