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THE IMPORTANCE OF PROTECTIVE RELAYING FOR WATER AND WASTEWATER TREATMENT PLANTS

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Introduction

While modern electrical power systems are extremely reliable, it's not possible to eliminate failures and abnormal conditions. Protective relays are applied to detect faults and abnormal conditions on an electrical system and control the operation of switching devices to isolate the disturbance from the rest of the system. With highly reliable electrical systems, protective relays may be called upon to operate very infrequently. However, the effects of faults and abnormal conditions can be severe and protective relay systems must be designed carefully with the ability to protect against the worst possible fault conditions. This paper briefly describes the basic goals and philosophies behind relay system design and the types of protection that are applied in water and wastewater treatment facilities. As motors for pumping applications are particularly critical to water and wastewater facility operations, the major faults and abnormal conditions that affect motors also are discussed. The relay schemes in this paper typically are applied to systems with operating voltages greater than 1000 volts.

Purposes of Protective Relaying

An electrical fault is the establishment of an unintentional conducting path. On a three-phase system, the unintentional path may be between two- or three-phase conductors, or between one or more phases and a metal enclosure or the earth. A fault can be established through:

- Insulation failure due to age
- Overheating
- Exposure to the elements
- A lightning strike
- Mechanical failure of equipment
- Misapplication of equipment
- Accidental forced contact between conductors, such as from a maintenance error, vehicle accidents, or animal contact

Abnormal conditions may exist with or without an actual failure but may lead to a failure if not corrected. Abnormal conditions include:

- Overloading
- Low voltage
- High voltage
- Incorrect frequency

- Unbalanced current
- Unbalanced voltage

A complete protective relaying system consists of all the components necessary to detect faults or abnormal conditions and operate the appropriate switching devices, such as circuit breakers or automatic switches. Proper operation requires integrating a variety of electrical and electronic technologies at both high and low power levels. Major components are as follows.

- Current transformers (CTs) and voltage transformers (VTs) to reduce the voltage and currents of the electrical power system to levels suitable for relay inputs. Secondary wiring and disconnects are associated with the current and voltage transformers.
- The protective relays and associated auxiliary relays, selector switches, control circuit disconnects, indicating lamps, and control wiring to the circuit breakers. The system may also include separate relays for primary and backup protection to avoid losing protection if a relay fails.
- The circuit breakers or automatic switches that will perform the switching at power circuit voltage and current levels. These devices consist of switching mechanisms, interrupter assemblies, trip and close coils and control circuits.
- A reliable source of control power for the relays and circuit breakers. Control power must be available even if the power system is faulted or otherwise unavailable. While various control power arrangements have been used, the most reliable is a substation battery with a charger.

Basic Design Goals

Regardless of the complexity, any protective relay system design is governed by a few basic goals and philosophies. These goals include speed, selectivity and reliability.

Speed

High-speed operation of a protective relay system is necessary to limit the effects of a fault, which can include equipment damage, process upset, and hazards to personnel. A fault typically causes an “overcurrent” condition, with the current exceeding the rating of the line conductors, switches and transformers that must carry the current. This may cause a violent arc at the fault location. The fault may also cause abnormally high or low voltage. By definition of a fault, the equipment is damaged or destroyed but the overcurrent, arcing and abnormal voltage may also damage equipment at other locations on the system. The risk of more widespread damage increases if the fault is allowed to persist. Even if damage does not occur, the abnormal conditions may result in tripping other devices and upsetting the processes supplied by the system. High-speed operation of the protective relay system is essential in limiting the equipment damage and risk of a wider system disturbance due to a fault.

Beyond risk of equipment damage and process upset, the failed insulation and arcing associated with the fault presents hazards to personnel who might be in the vicinity. Electric shock hazards are well-known. Becoming more formally recognized are the hazards associated with an arc flash including flash burns, hearing loss from the blast, vision loss from the flash, and injury due to the impact of particles expelled by the blast. The National Electrical Code (NEC) requires equipment to be marked with an arc flash warning if it’s likely to require servicing while energized. OSHA has enforced requirements for arc flash hazard analysis and personal protective equipment found in NFPA 70E-2004, *Standard for Electrical Safety in the Workplace*.

The energy received by a person exposed to an arc flash depends on the current magnitude and the time it persists. High-speed protective relaying can dramatically reduce arc flash energy and hazards to personnel.

Selectivity

Selectivity is the ability of a protective relay system to isolate the smallest portion of a system necessary to isolate a fault or abnormal condition. Obviously, it would be a major process upset to trip a switchgear main breaker for a fault on a motor circuit supplied from a feeder breaker and downstream motor control center (MCC). While limiting damage and system upset demands high speed, selectivity often demands some delay to allow time for protective relays closest to the disturbance to operate. Coordination studies attempt to determine settings for time-overcurrent devices that will balance the opposing demands of speed and selectivity. Generally time-overcurrent coordination requires longer time delays for devices closer to the supply point of a system. As discussed later, differential relaying can be used to avoid excessive time delays at certain locations.

Reliability

Reliability of a protective relay system is defined in terms of two components: dependability and security. Dependability is the ability of the relaying system to always operate correctly for a fault or abnormal condition. Security is the ability of the relaying system *not* to operate when there is no abnormal condition present, or if the condition is temporary or should be isolated by relays in another part of the system. As with speed and selectivity, dependability and security are opposing demands. Improving dependability tends to reduce security and vice versa. All protective relay system designs attempt to balance the competing requirements of dependability and security. Lowering the overcurrent pickup setting of a relay is a simple way to increase dependability. Adding time delay is a simple way to increase security. In addition, relay designs often include features that enhance both dependability and security. For example, restraint elements may be a security feature for a differential relay so the relay avoids tripping for faults that should be cleared by other devices. The same differential relay may also have an unrestrained overcurrent element with a high setting to maintain dependability. A motor protective relay may have firmware routines that recognize when the motor is started and restrain tripping on the high starting current during a programmed interval. An overcurrent setting can be closer to the motor starting inrush current for better dependability while the restraint feature maintains security.

Zones of Protection

Visualizing an electrical power system as divided into zones of protection allows protective relays to be applied in a logical way to achieve the goals of speed, selectivity and reliability. The concept is simple: each component is a separate zone requiring specific protection. In a water or wastewater treatment facility, the protective zones might be the main transformer, medium voltage switchgear, medium voltage distribution line, unit substation transformer, low voltage switchgear, low voltage feeder, motor control center and motor. The zones are separated by switching devices that will operate to selectively isolate a faulted zone from the rest of the system.

Zones of protection are defined by the location of switching devices and the current and voltage transformers that provide inputs to the protective relays, therefore the zones should overlap. For example, a main transformer supplies medium voltage switchgear through a main breaker. The transformer zone should include the medium voltage switchgear main breaker. The switchgear zone also should include this main breaker. Transformer relaying and switchgear relaying can both respond to faults at the switchgear main breaker.

While it may seem obvious, it is important to include the correct logic and wiring to trip all switching devices necessary to isolate a faulted zone. For example, if a transformer is equipped with high and low side circuit breakers, both breakers must be tripped by the transformer protective relays. Bus protective relays must trip the main, tie, and feeder breakers for the protected bus section. Auxiliary relays are used to trip the required breakers and may provide a lockout function so that equipment is not inadvertently re-energized by operators after a trip.

Historically, individual protective relays have been designed to detect specific conditions: one relay detects overcurrent for fault protection, one relay detects undervoltage, one relay detects motor overloading, etc. and a package of individual relays provided the protection for a particular zone. This was a natural design because specific types of electromechanical elements or analog electronic circuits were required to perform the different types of measurements. Modern protective relays are now microprocessor-based, however, storing the various protection measurements and logic decisions in relay firmware. This means that once the currents and voltages are converted to digital form, one microprocessor-based instrument running multiple algorithms can perform multiple protective functions and provide all the protection for a particular zone.

Types of Protection

Since the zone of protection consists of a specific type of component, the appropriate relay protection for each zone must be chosen. This section describes the most commonly types of protective relays and some of the ways they are designed and applied to balance dependability and security.

Overcurrent Protection

Overcurrent protection is perhaps the most basic form of protection and can be applied to any power system component. As current transformers supply the current to be measured, if the current is above the pickup setting for the set time delay, the relay produces a trip signal. The zone protected by an overcurrent relay depends on the pickup setting. A lower pickup setting extends the zone and allows the relay to respond to faults farther away from its location. Since zones of protection should overlap, an overcurrent relay should be able to respond to faults in at least the next adjacent zone. Time delay is used to allow the relays in the next zone to operate first and achieve selectivity. Overcurrent relays typically provide a settable time delay and an instantaneous function to trip with no intentional time delay. To maintain selectivity, the instantaneous pickup setting must be high enough so that it does not respond to faults in other zones.

In a three-phase system, separate overcurrent protection is provided for faults involving only the phase conductors and faults involving one or more phase conductors and ground. The ground current measurement can be made indirectly with current transformers connected to form the sum of the phase currents. This sum equals the ground current. Another way to measure ground fault current on insulated cable circuits is to pass the insulated conductors through a specialized current transformer designed to accommodate the conductors in its window. With this arrangement, the summation is performed magnetically. Measurement can also be made directly with a current transformer installed at the location to which ground fault current returns in the circuit — typically a transformer or generator neutral terminal.

The advantage of including both phase and ground overcurrent protection is to create greater sensitivity. Overcurrent pickup settings for phase faults must allow for normal and emergency load current in the phase conductors. Under normal conditions, current in the neutral or ground is very small and may approach zero. Ground overcurrent pickup settings do not have to accommodate load current and can be much lower (more sensitive) than phase overcurrent pickup settings. Ground faults typically have higher impedance in the circuit path than phase faults and the circuit may have current-limiting impedance intentionally added. The result is that for most locations on a system, ground fault current is less than phase fault current. Since most faults (80% or more) involve ground, sensitive ground overcurrent protection separate from phase overcurrent protection is desirable.

Many water and wastewater electrical systems are designed as radial systems where a source at one end of the system supplies the distribution network and loads connect to the other end of the system. In radial systems, the path for fault current is readily defined. For those faults, the current does not flow through the paths between the fault and the loads, except for transient current from stored energy in rotating motors. For improved reliability, or to increase load-carrying capacity, some systems are designed with multiple sources connected together. For example, two or more utility lines may be connected to a common substation bus or the facility may operate a methane-fueled cogeneration plant connected to the distribution system that is also supplied by a utility service. For such systems, fault current might flow through a protective zone for faults on either the source side or load side of that zone. Overcurrent relays may respond to faults in many zones of the system or even faults on the utility system. It’s typically not possible to develop settings that will provide the necessary sensitivity and selectivity for all fault locations on such a system. Directional overcurrent relays determine the location, upstream or downstream, of the fault relative to the zone that detects the fault current. The directional measurement is made by comparing the measured current to a reference quantity, usually a voltage that does not change with fault location. Settings for a directional overcurrent relay are then made to meet sensitivity and selectivity requirements for faults in the desired direction.

If a water or wastewater facility operates generators in parallel with the utility system, directional overcurrent relays may be required at the service point to prevent the local generators from inadvertently energizing the utility system. If a fault occurs on the utility system, the local generation would continue to energize the fault, creating safety hazards for the general public and for utility crews making repairs.

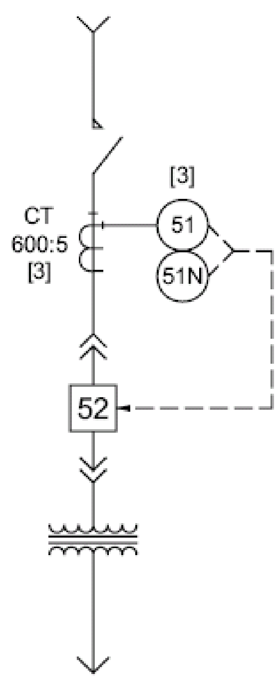

Figure 1: Typical Application of Overcurrent Relays

In Figure 1, the designation 52 is the IEEE Std. C37.2-1996 for a circuit breaker. The phase-time overcurrent relays are designated 51 and the ground time-overcurrent relay is designated 51N. If instantaneous phase or ground overcurrent protection were applied, the designations 50 and 50N would be added to the relay symbols. The bracketed [3] denotes that there are three phase overcurrent relays and three CTs. The dotted line from the relays to the circuit breaker denotes that the relays are wired to trip the circuit breaker on an overcurrent condition.

Voltage and Current Balance Protection

Three-phase power systems are designed and operated to achieve the most balanced voltage and current conditions possible. In a balanced three-phase system, the voltages are of equal magnitude and their sinusoidal waveforms are displaced from each other by 120 electrical degrees, or one third of a power cycle. The sinusoidal voltages also reach their peak values in a known repeated sequence. For example, the sequence might be phase a, phase b or phase c. With balanced voltages and balanced loads, the currents also will be balanced.

Unbalance of either voltage or current can be caused by a fault, an abnormal condition such as unintended load imbalance or an open conductor, or reversed phase connections. Deviation of the magnitudes or phase displacement angles indicates an unbalanced condition. Voltage and current unbalance beyond a small tolerance is particularly detrimental to rotating machinery such as motors and generators, and causes damage by overheating even when an overcurrent condition does not exist. Voltage and current balance relays measure the three-phase voltages or currents and calculate the degree of unbalance. Pickup settings usually are expressed in percent of the rated voltage or current and a time delay is typically used for security to allow an unbalanced condition to be corrected by fault protection relays in other zones.

Voltage balance relays can detect unbalance between the source and the point where the relay is applied, but not between the relay location and downstream loads. Typical applications for generators and motor circuits are at utility service points, at switchgear buses to control the automatic transfer between alternate sources, and to motor control centers or switchgear buses that supply multiple motors. Current balance relays are typically used to detect current unbalance for individual circuits.

Voltage-Based Protection

Several types of protective relays measure voltage to perform specific protective functions. Overvoltage and undervoltage relays operate when voltage is higher or lower than a settable level. The settings must allow for normal voltage variation associated with changes in load and utility service voltage tolerance. Typical applications are at utility service points, at switchgear used to connect generators to a system, and at switchgear buses to control the automatic transfer between alternate sources. Overvoltage relays also are used to detect ground faults on generators and systems designed with grounding impedance to limit ground fault current to very low values.

Overfrequency and underfrequency relays measure voltage to determine the system frequency. Deviation from the nominal frequency, 60 Hz in North America, might be caused by the failure of a generator governor but usually indicates a mismatch between the power input to system generators and the power consumed by the system loads and losses. Operation at off-nominal frequency causes fatigue and cumulative damage to generator steam turbine blades and frequency may be applied for steam turbine protection.

On a system level, off-nominal frequency may be accompanied by abnormal voltage and may indicate that the system is becoming unstable. Frequency relays may be applied for *system* protection to avoid a total collapse by disconnecting certain loads or tripping certain circuit breakers to separate the system into islands. This way stability can more likely be maintained or recovery more easily managed. Frequency relays may be applied at the utility service point for water and wastewater facilities having local generation. Often the utility will require such protection as part of the relaying package intended to prevent the local generation from energizing a fault on the utility system. For water and wastewater facilities with local generation, frequency relays may also allow the facility to separate from the utility and continue operating at least some of the processes in the event of a utility system fault and disconnection of service.

Synchronism check relays measure the magnitude and phase angle of the voltage across an open point where two sources are to be connected. The relays are not protective relays, but serve a supervisory role in controlling the operation of circuit breakers. The two sources may be utility services from separate substations. Often, one source is the utility service and the other source is a local generator. To connect the sources, the three-phase voltages must be nearly equal, the frequencies must be nearly identical, and the phase sequence of the sources must be the same. Generator paralleling controls automatically adjust governors and exciters to achieve synchronism before paralleling the generator with a utility system. Connecting two sources that are not in synchronism may result in damage to rotating machinery because of torsional stress to the shafts, and damage to the tie circuit breaker and switchgear with associated risks to personnel operating the equipment.

It is difficult to define a zone of protection for voltage and frequency relays that may respond to faults or abnormal conditions for any location on a system. Voltage and frequency relays usually are applied as a last line of defense to separate systems at interface points. Time delays are used to allow isolation of a fault or abnormal condition by relays in a specific zone.

Directional Power Protection

Power directional relays use voltage and current inputs to measure power. Either real power (watts) or reactive power (vars) can be measured, but for most applications, real power is the desired quantity. Since power is the product of voltage and current, there is directionality associated with the measurement. Direction is determined by the phase angle between the voltage and current waveforms and power is transmitted, or “flows”, from one point to another. For example, power flows from a source to a load, into or out of a switchgear bus and into or out of a generator. For systems with multiple sources, power can flow in more than one direction. A power directional relay operates when power flow is higher or lower than a set pickup in a specified direction. The pickup and directional settings are selected to indicate an abnormal or fault condition.

At a water or wastewater facility with local generation, loss of the prime mover power input to the generator will allow power to flow from the system into the generator and the generator will act as a synchronous motor. This condition mainly creates the risk of damaging the prime mover so a power directional relay is applied to detect power flow into a generator on loss of the prime mover.

If a wastewater facility operates a methane-fueled cogeneration plant, the service agreement with the utility company may or may not provide for the utility to buy surplus power from the facility. If there is no agreement for the utility to purchase power, a directional power relay may be required at the service point to prevent transmission of power from the cogeneration plant to the utility system. This relay may be part of the required protection at the service point to prevent the cogeneration plant from inadvertently energizing the utility system.

If two transformers supplied by separate utility feeders are connected to a common bus at a water or wastewater facility, a fault on one utility feeder will allow current and power to flow from the other transformer through the common bus and back through the first transformer to the fault. Depending on the fault type, location and transformer winding connection, the current may be nearly zero and the only power flow may be that associated with the transformer losses. The direction of the flow still will indicate an abnormal condition. Figure 2 shows directional protection applied to overcurrent relays for two sources operated in parallel. The designations 67 and 67N indicate directional phase and directional ground overcurrent relays respectively.

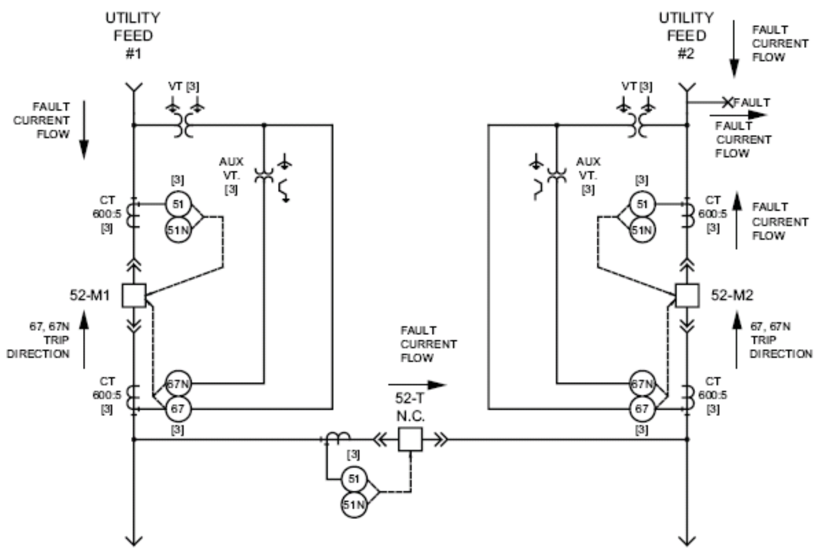

Figure 2: Example protective relaying arrangement for closed-transition primary-selective system

Differential Protection

Differential relays operate on one of the fundamental principles governing behavior of electrical circuits — Kirchhoff's Current Law. The law states that the sum of all currents flowing into an electrical node is zero. Stated another way, the current flowing into a node must equal the current flowing out of the node. A differential relay measures the sum of all currents connected to whatever node is being protected. If the sum is not zero, there is an unintentional path for current flow that creates an unbalance between current entering and current leaving the node. The unintentional path is a fault between phases or between one or more phases and ground.

It is perhaps easiest to visualize differential protection applied to a substation bus since a bus exactly fits a simple definition of an electrical node: a junction with current-carrying branches connected. For relaying purposes, other power system components also meet the definition of a node. For example, a transformer can be considered as a node with high and low side conductors carrying current to and from the node. Motor and generator windings have leads on each end that carry current into and out of the windings. Transmission lines have two or more terminals where currents flow in and out. For water or wastewater facilities, differential relaying is typically applied to buses, transformers and rotating machinery.

A basic form of differential relaying consists of multiple current transformers with their secondary terminals connected in parallel. The parallel connection sums the currents from the individual current transformers. An overcurrent relay is connected to the CT secondary junction to measure the differential current. The differential connection provides significant advantages over simple overcurrent relaying in terms of selectivity, sensitivity, and speed. Differential current transformer connections define the zone of protection. With a properly designed system, differential relays will not detect normal load current nor will they operate for faults outside the defined zone. Since a differential relay does not respond to load current, the pickup can be very low to provide sensitive protection. Since the protection is inherently selective, the relay can therefore be allowed to operate with no time delay.

Such ideal characteristics depend on perfect current transformers, all perfectly matched. Practical current transformers have limits beyond which the measured current will not accurately represent the actual current. Current transformer errors will result in a false differential current in the relay. For example, a fault might occur just outside the protected zone but one or more current transformers may be unable to accurately reproduce the primary current in the secondary circuit. The sum of all the secondary currents will not equal zero and the differential relay may trip incorrectly, resulting in a loss of security and selectivity.

Differential relays and relay schemes are designed to accommodate current transformer error without loss of reliability. Several types of differential relay systems have been developed to maintain reliability when current transformer performance is not perfect and each type has its own operating principles and application requirements. Two of the most common systems that are used at water or wastewater facilities are the multi-restraint system and the high impedance system.

Multi-restraint differential relaying is based on the principle that current transformer error is likely to increase as the primary current increases. A high CT secondary current is more likely to be inaccurate than a low current. Currents from individual circuits connected to a protected zone are used to restrain operation of the relay. Higher individual currents restrain relay operation so that a higher differential current is required to produce a trip signal. To obtain this characteristic, differential relays calculate a differential quantity and a restraint quantity.

$I_d = | I_1 + I_2 + \ldots|$
$I_r = | I_1 | + | I_2 | + \ldots$

Where I_d = differential current
I_r = restraint current
$I_1, I_2, \ldots$ = individual measured current for each circuit connected to the differential zone

For some relays, the restraint quantity is calculated as I_r = Maximum of $| I_1 |, | I_2 |, \ldots$

The symbol |*| indicates the magnitude of a phasor quantity that has both magnitude and phase angle. The differential current is the phasor sum of the individual currents. The restraint current is the sum of the individual current magnitudes or the maximum of any individual current.

A typical differential relay will require the current I_d to be some fraction of I_r to produce a trip signal. If the fraction is constant for any value of I_r, the relay provides a constant percentage characteristic. If the fraction changes for different values of I_r, the relay is said to provide a variable percentage characteristic.

A lower percentage setting provides higher sensitivity for lower currents where current transformer error is expected to be small. A higher percentage setting provides better security for high fault current where current transformer error is likely to be significant and high sensitivity is not as important. Modern microprocessor-based differential relays usually provide settings for minimum pickup and two percentage settings for different ranges of I_r.

High impedance differential relaying uses the fact that a current transformer must develop a voltage to produce its secondary current. The current transformer characteristics place a limit on the voltage that can be developed. For high impedance differential relays, the current transformer secondary terminals are all connected in parallel to perform the summation. Instead of measuring the differential current, the relay places a high impedance voltage measuring element at the junction of current transformer secondary connections. If no fault is present, the currents sum to zero at the junction and the voltage is zero. If a fault is present, the currents will not sum to zero and the current transformers will attempt to force current through the high impedance relay.

Rather than measuring the current, the relay measures the voltage produced by the current transformers. The voltage produced depends on the magnitude of the fault current. For a severe fault inside the zone, the voltage will tend to approach the maximum that the current transformers can produce. Because the measured quantity is voltage instead of current, this type of relaying is sometimes referred to as high impedance voltage differential relaying. Current transformer error can result in a significant voltage produced for faults outside the protected zone. The voltage setting must be low enough for good sensitivity and high enough to avoid operation on the error voltage for faults outside the protected zone.

Application of Protective Relaying to Specific Equipment

This section shows what types of protection are applied to specific equipment that might be installed at a water or wastewater facility and some typical criteria that would be used to develop protective settings. The information is intended to give general understanding and guidance but is not a complete discussion of all the equipment characteristics and relay capabilities that must be considered to develop a protective relaying system. The choice of actual protection and relay settings to be applied depends on the specific conditions for each installation and may differ from those discussed in this section.

Transformer Protection

In addition to the damage at the immediate location of an internal fault, a transformer is subject to damage from the fault current flowing in its windings. Damage is caused by heating and by magnetic forces associated with the current. [3] Magnetic forces can cause deformation or destruction of the windings while thermal and mechanical damage also can occur when the transformer supplies current to an external fault. High speed protection is essential to avoid thermal and mechanical damage for external faults and to limit the damage for internal faults.

For a smaller transformer, perhaps less than 10 MVA capacity, protection may simply be power fuses applied at the high side terminals. Protective relays are typically applied to larger transformers or if there is a design preference to use circuit breakers instead of fuses. Phase and ground overcurrent protection may be the only relaying applied. For more critical transformers, the main protection is often differential relaying. Overcurrent relays are then used as backup protection. A typical configuration for overcurrent relaying is time and instantaneous overcurrent relays for phase and ground faults on the transformer high side, and separate time overcurrent relaying for phase and ground faults on the low side. If the transformer provides resistance grounding for the system, ground fault current will be limited to values that might not be reliably detected by differential relays. In these cases, separate ground differential relaying can be applied.

Differential relays may require general settings such as the transformer rated voltage, kVA, winding connections, and CT ratios. Protective settings may include minimum pickup, slope of the differential characteristic, and settings to inhibit relay operation when the transformer is energized after being out of service and magnetizing inrush current flows. A typical minimum pickup setting might be 15 percent of the transformer rated current. Differential relays may also provide an instantaneous overcurrent element that measures differential current but is not restrained. The unrestrained instantaneous pickup setting must be high enough so that it can only operate for transformer internal faults.

For example, in a radial system, the unrestrained instantaneous pickup setting would be lower than the current for a fault at the transformer high side terminals but higher than the current for a fault at the low side terminals. If the instantaneous element is not restrained for magnetizing inrush, its setting must also be higher than the inrush current.

Some general guidelines for transformer overcurrent relay settings are as follows.

- *High side phase instantaneous overcurrent:* Set similar to the unrestrained differential relay instantaneous element. Set higher than the current for a fault at the low side terminals, higher than magnetizing inrush current, lower than current for a fault at the high side terminals.

- *High side phase time overcurrent:* Set pickup to allow for normal and emergency loading and to comply with requirements in NEC Table 450.3(A). [11] Set time delay to coordinate with industry-standard transformer damage limits [3] and to coordinate with time overcurrent devices upstream and downstream from the transformer.

- *High side ground overcurrent:* Transformer winding connections determine the criteria for setting ground overcurrent relays. Usually, high side winding is connected in delta and low side winding is connected in wye. There is no ground current on the delta side for a ground fault on the wye side, and ground relays can be set very sensitively. There is a possibility that magnetizing inrush current could cause current transformers to be inaccurate, resulting in a current measured by the ground overcurrent relay when no ground fault exists. For security, it may be desirable to set the high side ground instantaneous relay at perhaps 25 percent of the setting for the phase instantaneous overcurrent relay. With a delta-wye connection, high side ground time overcurrent relaying is not required but may be applied for redundancy. A pickup setting of 25 percent of transformer full load current and time delay of 0.1 second at the maximum ground fault current is suggested.

- *Low side phase overcurrent:* Instantaneous overcurrent is not recommended because it cannot be coordinated with downstream overcurrent devices. Set the time overcurrent pickup to allow for normal and emergency loading. Set the time delay to coordinate with upstream and downstream overcurrent devices and to coordinate with the transformer damage limits.

- *Low side ground overcurrent:* As with the low side phase relays, instantaneous overcurrent is not recommended because it cannot be coordinated with downstream overcurrent devices. Set the time overcurrent pickup at 25 percent or more of the transformer full load current to allow for load unbalance and to facilitate coordination with downstream overcurrent devices. Usually, the transformer winding connection eliminates the need to coordinate the low side ground overcurrent relay with devices on the high side, and the time delay can be set to coordinate with downstream devices.

Other protection using devices other than protective relays might be applied for larger transformers. For example, liquid-filled transformers can be equipped with a specialized relay to detect sudden pressure changes caused by faults inside the transformer tank. Arcing vaporizes the insulating fluid in the immediate vicinity of the fault and the resulting pressure wave propagates through the tank volume. The sudden pressure relay does not respond to gradual pressure fluctuations caused by changes in loading or ambient temperature. Sudden pressure relays can provide more sensitive fault detection than differential relays but cannot respond to faults that are in the transformer zone but outside of the tank.

Liquid-filled transformers can be equipped with sensors to measure the temperature of the insulating fluid and the hottest part of the winding. Dry type transformers may include thermocouples to measure winding temperature. Gauges for oil temperature, hot spot temperature, and winding temperature can be equipped with settable contacts to start cooling fans, provide an alarm, and provide a trip signal.

While overcurrent relays provide some degree of overload protection, they are primarily intended for fault protection. Direct temperature measurement can provide overload protection as well as protection against transformer cooling system failures. Since it is a direct indication of the highest temperature in any winding, the hot spot temperature gauge is used for tripping. For liquid-filled transformers, trip settings may be based on maximum hot spot temperatures of 180 ºC for power transformers and 200 ºC for distribution transformers. [1]

Figure 3 shows AC current connections for a typical electromechanical transformer differential relay. With electromechanical relays, current transformer connections are made to compensate for the phase shift introduced by the main transformer winding connections. The figure shows CT connections for a delta-wye transformer. Microprocessor-based relays compensate for the phase shift with settings and can utilize wye-connected CTs regardless of the main transformer winding connection.

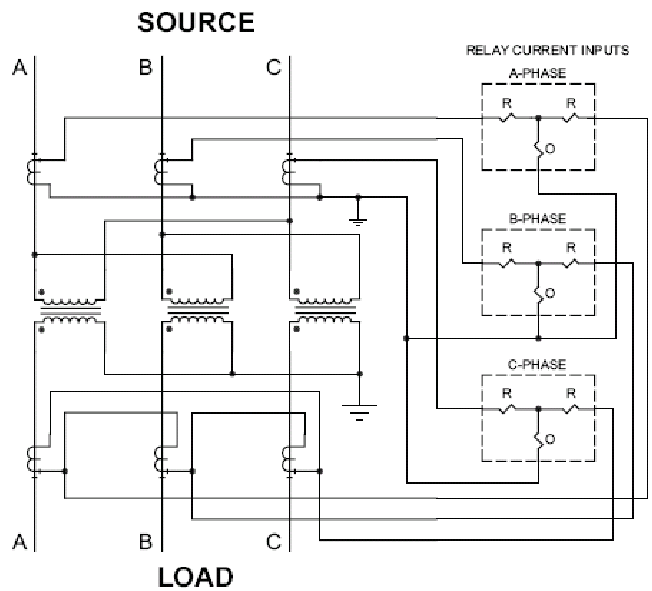

Figure 3: Typical application of current-differential relays for delta-wye transformer protection

Figure 4 shows a one-line representation of a transformer differential scheme, including the circuit breakers and trip logic. In this figure, the secondary protective device is shown as a low voltage power circuit breaker. It is important that the protective devices on both sides of the transformer be capable of fault-interrupting duty and suitable for relay tripping. A lockout relay is used to trip both the primary and secondary devices. The lockout relay is designated 86T with 86 the designation for a lockout relay and T designating transformer protection. The differential relay is denoted 87T with 87 the designation for a differential relay and T again designating transformer protection. The wye and delta CT connections also are noted.

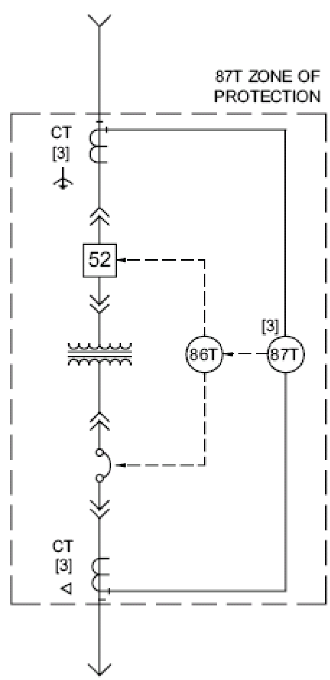

Figure 4: Transformer differential relay application from figure 3 in one-line diagram format

Bus Protection
Differential protection should be applied to any open air or switchgear bus. The high speed and selectivity of bus differential protection are important in limiting hazards to personnel and in avoiding loss of service to large parts of a system. For example, large switchgear buses typically are split into sections with tie breakers between the sections and a separate source for each section. The tie breakers allow operating flexibility but also allow a faulted bus section to be isolated while maintaining service to circuits on the other sections.

Bus differential relay settings are of concern mainly for high impedance and partial differential schemes. For high impedance differential relaying, the voltage setting must be higher than the maximum error voltage for a fault outside the bus differential zone. The settings require calculations based on CT secondary circuit impedances and CT characteristics. [2]

Partial differential protection, sometimes called bus overcurrent is sometimes used for buses where current transformers are not available for all connected circuits. A typical scheme would use CTs from the main and tie breakers connected to measure total bus current. The protection is based on overcurrent relays and setting guidelines are similar to those for overcurrent relays. The pickup setting must allow for maximum total load current supplied by the bus and the time delay must be set to coordinate with upstream and downstream time overcurrent devices.

Distribution Feeder Protection
Distribution feeders at water and wastewater facilities may be overhead or underground. While overhead lines can suffer a fault without permanent damage, cable faults are generally permanent. Cables can be susceptible to heating damage from fault current because the conductors are covered with insulation and the cables are installed underground or in conduit. Industry standards define damage limits for power cables. [4]

A further concern with underground cables is that the shields typically have a much lower cross-sectional area than the main conductor and are particularly vulnerable to damage from fault current. Protection for distribution lines and cables usually is provided by phase and ground overcurrent relays.

Some general guidelines for feeder overcurrent relay settings are as follows.

- *Phase instantaneous overcurrent:* Set lower than the available fault current at the beginning of the line but higher than the available fault current at the end of the line or at the closest downstream overcurrent device. A suggested minimum setting is 125 percent of the current at the end of the line or closest downstream device. For distribution feeders that supply unit substation transformers, set high enough to avoid tripping for faults on the transformer secondary side. The goal is to provide the largest zone possible for instantaneous protection while maintaining coordination with downstream overcurrent devices. Also, set high enough to avoid tripping for transformer magnetizing inrush current. Developing a suitable setting may require judgment and making tradeoffs between the need for high speed protection and the need to coordinate with downstream overcurrent devices.

- *Phase time overcurrent:* Set pickup to allow for normal and emergency loading. Set no higher than 600 percent of the feeder conductor capacity to comply with NEC Article 240.101. [11] To ensure adequate sensitivity, the pickup should be no higher than perhaps one-third of the available current at the most remote downstream overcurrent device. Usually, available fault current is more than adequate to meet this guideline. Set the time delay to coordinate with upstream and downstream overcurrent devices.

- *Ground instantaneous overcurrent:* The criteria are similar to those for phase instantaneous overcurrent relays except settings are based on ground fault current.

- *Ground time overcurrent:* Usually, distribution feeders at water and wastewater facilities do not supply loads connected phase to neutral, and a sensitive pickup setting could be used. A pickup setting of 25 percent or more of the phase relay pickup may be required to coordinate with downstream overcurrent devices. As with phase relays, the pickup should be no higher than perhaps one third of the available ground fault current at the most remote downstream overcurrent device. The time delay should be set to coordinate with upstream and downstream overcurrent devices.

Motor Protection

Some of the most significant loads at water and wastewater facilities are pump motors. Examples of critical pump loads include intake pumps for water filtration, influent pumps at wastewater treatment plants and output pumps maintaining header pressure for water distribution. Loss of pump motors can cripple operation of water or wastewater facilities. Dependability of pump motor protection is important in guarding against damage to motor assets, and security is important in preventing major plant upsets due to loss of pumping capability.

All motors require overload and short circuit protection. The simplest protection is a relay for overload and fuses for short circuit protection. Overcurrent relays may be applied instead of fuses for short circuit protection. As with transformers, differential relays may provide the main protection for critical motors with overcurrent relays applied for backup protection. For larger or more critical motors, additional protective functions may be applied as described in this section.

This discussion is mainly concerned with AC induction motors, which are the most widely applied type. Many of the protective relay concepts apply to synchronous motors as well but synchronous motors will have additional protection associated with the separately excited rotating field. Pump motors, like other rotating machinery, may be subject to a greater variety of abnormal operating conditions than other power system equipment because of the mechanical load. Application of protective functions is discussed in terms of the types of faults and abnormal conditions that may be experienced by pump motors and other motors at water and wastewater facilities.

Some general guidelines for large motor relays and settings are as follows.

- *Overload:* Operating a motor at a load beyond its nameplate horsepower rating risks damaging the motor insulation because of excessive heat. Overload relays may accept inputs from resistance temperature detectors embedded in the motor windings. This gives direct temperature measurement of the stator and provides good protection for overload or for a failure in the motor cooling system. Many motors are not equipped with resistance temperature detectors (RTDs) and overload relays provide protection based on measurement of the stator current. Temperature rise in the motor is proportional to the square of the RMS current. Basic settings include the motor rated current, the maximum allowable current based on the motor service factor, and time constants for heating and cooling. From these settings, the relay calculates a quantity for permissible heat rise, and the time to reach the permissible heat rise based on the square of the current. This calculation results in a time-current overload characteristic with time as a logarithmic function of current squared. As the motor runs, the relay calculates the heat rise as a percentage of the permissible rise. Under normal conditions, the heat rise will stabilize at some value less than 100 percent. The current used for calculation may include a factor to account for additional heating due to unbalanced current. Relay logic uses the cooling time constant to decrement the calculated heat rise when the motor is not running. Each time the motor is started, the relay can determine whether the motor is starting from a hot condition or a cold condition and will adjust the overload characteristic accordingly. [5] Current-based overload protection is less effective than RTD-based protection because current-based protection cannot detect a failure of the motor cooling system.

- *Stator faults, instantaneous overcurrent:* Since a motor is an end-use device, there are no downstream devices with which a motor overcurrent relay must coordinate. Therefore instantaneous protection can be used to provide the fastest clearing time for motor faults. The instantaneous relay should be set lower than the fault current available at the motor terminals but higher than the maximum possible starting current. The starting current depends on the motor code letter on the nameplate and on the starting method. An often-used rule of thumb is that starting current is approximately six times full load current for full-voltage starting. A factor of 1.1 may be applied to account for higher voltage at the starter prior to the motor being connected and a factor of 1.6 may be applied to account for asymmetrical sinusoidal starting current due to magnetic effects associated with energizing the iron core windings.

- *Stator faults, time overcurrent:* Time overcurrent is intended to provide protection for stator faults with lower current magnitude. A suggested setting range is 125-175 percent of full load current, though a higher setting may be required for motors with very long starting times. Set the time delay to provide a margin of perhaps 2-5 seconds higher than the motor starting time but to allow tripping before the permissible stall time of the motor. [6] These guidelines indicate the need to base overcurrent relay settings on specific information about capabilities and performance of individual motors. The manufacturer can usually provide this information.

- *Stator faults, ground overcurrent:* Ground overcurrent relays may be connected to the phase CT residual circuit or to a single CT that encircles all three phase conductors. For a residual connection, the CTs may produce errors during motor starting, resulting in the ground relay measuring current when no fault exists. A time delay relay with a very sensitive pickup setting and a short time delay may prevent undesired tripping in this case. For a CT encircling all the phase conductors, there is less chance of error current and an instantaneous relay with a low pickup setting for good sensitivity often is used. Performance capabilities of the current transformer used to encircle the conductors may limit sensitivity of the scheme.

- *Stator faults, differential protection:* For large motors, the starting current may approach the available short circuit current, making application of instantaneous overcurrent relays difficult. [2] In such cases, differential protection can be applied. Motor differential protection generally takes one of two forms. A percentage differential relay can be applied to protect each phase, similar to a bus differential relay. Alternately, leads from each end of the motor winding can be passed through a CT with an instantaneous overcurrent relay measuring any difference between current into the winding and current out of the winding. This so-called self-balancing differential scheme is applicable to motors small enough to allow the leads to be passed through the CT window. For either scheme, terminals must be available for both ends of each phase winding.

- *Excessive starting time:* Under normal conditions, a motor draws a large current while it is accelerating to rated speed. As the motor approaches rated speed, the current decreases to a value corresponding to the mechanical load. Debris in a pump impeller or a failed bearing may cause a pump motor to accelerate slowly, fail to reach full speed, or fail to turn altogether. Current will be sustained at a level approaching or equal to the locked rotor current and the motor may be damaged by overheating. The overload function is intended for running motor protection and may not respond fast enough to an excessive starting time condition. Modern protective relays recognize a motor start attempt by measuring the current as it increases beyond a minimum threshold. If the current then exceeds the setting for more than a set time delay, a trip signal is generated. If the motor slows and then reaccelerates, the relay logic recognizes that the current has not passed through the starting threshold and excessive starting time protection remains inactive. A typical value for the starting current threshold might be 10 percent of rated current and a typical current setting indicating excessive starting time might be 50 percent of the locked rotor current. The time delay must be longer than the normal starting time for the motor and its connected load. [5]

- *Locked rotor protection:* Locked rotor protection is closely related to excessive starting time protection. The difference is that relay logic is used to recognize that a blocked rotor condition has occurred for a motor already running. If motor current increases from some level higher than the starting threshold current to a level higher than the locked rotor threshold for a set time delay, the condition is recognized as a jam or blocked rotor. Excessive starting time and locked rotor protection logic share the locked rotor threshold setting, typically some fraction of locked rotor current, such as 50%. The minimum current threshold to indicate that the motor is running, typically 10% of rated current, provides security against tripping for normal start attempts. The locked rotor time delay also provides security against tripping for temporary overloads or motor reacceleration.

- *Current balance protection:* Unbalanced current can cause motor overheating even when the motor is not overloaded. For unbalance conditions, overheating typically occurs because of current induced in the rotor. Current unbalance can be caused by an open conductor (blown fuse, broken connection), severely unbalanced load, or by failure of voltage regulating equipment. Usually, current unbalance protection is applied to an individual motor or to a group of motors where the normal current unbalance is expected to be small. Depending on the severity of the unbalance, stator current magnitudes may be well within the normal range and overload protection may not operate for unbalanced conditions. A typical setting might be 10-15 percent of rated current with a time delay of five seconds to avoid tripping the motor for temporary unbalance or abnormal conditions that can be corrected by operation of protective relays on another part of the system. Relays may calculate a time-current characteristic based on the square of the unbalance current so that more severe unbalance results in shorter relay operating time.

- *Voltage balance protection:* Voltage unbalance can be caused by unbalanced loading, failure of voltage regulating equipment, or an open phase conductor. The most severe voltage unbalance is a reversal of the normal phase sequence. A phase reversal may be caused by improper switching or incorrect connections in the utility or plant distribution system due to errors during maintenance or repair. Motors are very sensitive to unbalanced voltage and a five percent voltage unbalance can result in a motor current unbalance of 15 percent or more. For a phase reversal, induction motors will run backwards. A typical setting is five percent of rated voltage. A time delay of perhaps five seconds is used to allow the unbalance to be corrected by operation of protective relays on other parts of the system. Voltage unbalance protection is typically applied to a switchgear bus that supplies many motors so the time delay must be longer than the operating time for current balance protection or other protection applied to individual motors. The protection can detect open phase conditions between the power system source and the relay location but not open phase conditions between the relay and the motors.

- *Loss of load:* Loss of mechanical load can be caused by loss of prime in a pump, or a failed shaft, drive belt or coupling. Risks include upset to the process because of loss of prime and increased equipment damage in the case of mechanical failure. The condition is recognized by relay logic as a decrease of motor current to some level below minimum expected load. For security, the current setting must be above a threshold, such as 10 percent of rated current, indicating the motor is running. Also, a time delay is used to avoid tripping for temporary variations in the mechanical load. The current setting also must allow for the motor to run at the minimum expected load. The protection may not be applicable if the motor will run for no-load conditions and the current setting cannot reliably indicate a loss of load.

- *Starts per hour:* Each time a motor starts, it is subject to heating from the starting current. Normally, once the motor is running, the cooling system removes the heat generated by the starting current. If the motor is started while still hot from running, heating will be more severe than when the motor is started from a cold condition. If too many start attempts are made without letting the motor run or allowing time for the motor to cool while stationary, damage will result from overheating. Starts per hour protection logic recognizes a start attempt by measuring the current as it increases beyond a minimum threshold, such as 10 percent of rated current. A counter is incremented and further starting attempts are prevented if the count exceeds the setting for the time period preceding the current start attempt. Starting will be inhibited until the relay logic recognizes that enough time has passed so that a new start attempt is within the set limits. The protection is further refined by recognizing a hot start if the calculated heat rise exceeds 50 percent of the permissible heat rise, as calculated by the overload protection logic. [5] Starting can be inhibited if the number of consecutive start attempts (hot or cold) exceeds corresponding settings. Start attempts are recognized as consecutive if they occur in a period equal to the set time period divided by the number of allowable start attempts. If the motor slows and then reaccelerates, heating similar to that for starting occurs and the logic can be programmed to recognize a reacceleration as a starting attempt. Settings for starts per hour must be based on the motor capability specified by the manufacturer.

- *Undervoltage:* Attempting to start a motor with abnormally low voltage may result in excessive starting time or failure to achieve rated speed. The motor may be damaged by heating from excessive current. Similarly, a running motor supplied with abnormally low voltage will draw excessive current and may be damaged by overheating. Undervoltage protection may be applied to individual motors or to switchgear supplying a group of motors. The protection may be used to supervise starting or to trip for undervoltage. Motors are generally expected to operate correctly for voltage at least 90 percent of the nameplate rating. Faults or abnormal conditions on the distribution system may cause the voltage to be below 90 percent of nominal for short times. Suggested undervoltage settings are no higher than 80 percent of motor rated voltage with a time delay of perhaps five seconds to allow protective devices on other parts of the distribution system to operate.

- *Remnant undervoltage:* A water or wastewater facility may provide alternate sources to critical pump motors. If the normal supply is lost for any reason, automatic switching is initiated to transfer the motor loads to an alternate source. The transfer is typically initiated by an undervoltage relay operating to indicate loss of voltage. When the power supply to a motor is lost, the motor terminal voltage does not disappear immediately but is sustained by its rotating inertia and internal magnetic field. This remnant voltage decays according to the motor and load characteristics. Depending on the speed of the transfer scheme, voltage may be present at the motor terminals when the transfer occurs. Application of the alternate source voltage to the motor with its remnant voltage can produce severe torque on the motor shaft as well as voltage and current transients. The result can be damage to the shaft, damage to the motor windings, and damage to other connected equipment. Remnant undervoltage logic prevents the transfer until the motor voltage has decayed to a safe level. A typical setting is 20-25 percent of motor rated voltage. For additional security, a time delay is used to ensure the remnant voltage remains below the setting.

Fluid flow for centrifugal loads such as pumps can be regulated with throttle valves or by controlling the motor speed. Controlling the motor speed can yield significant energy savings when compared to throttle valves and pump motors since some applications in water and wastewater facilities may be controlled by adjustable speed drives. The adjustable speed drive unit may include many of the protective functions just discussed. In some cases, separate relays may be installed to provide additional protective functions, such as measuring winding or bearing temperature. The protective functions available in an adjustable speed drive should be checked and external relays should be added if necessary to provide full protection.

Generator Protection

Generators have some unique characteristics and like other rotating machinery, are subject to a wide range of abnormal conditions. For these reasons, generator protection is probably the most complex relaying applied at water and wastewater facilities. This discussion will touch on some of the main characteristics of generator protective relays. References cited with this paper contain much more detailed information.

Some of the important characteristics of generators that affect relaying requirements are as follows.

- Ground faults in generator windings can be difficult to detect. Generator windings typically are connected in a wye configuration. The common point of the wye is the generator neutral. If a ground fault occurs near the generator terminals, the ground current is generally high enough to allow reliable detection. If a ground fault occurs near the neutral end of a winding, there is relatively little voltage available and the ground fault current will be very low.

- In addition to the variability of ground fault current, generators rated over 1000 volts generally have their neutral terminals connected to ground through an impedance, usually a resistor. The impedance is intended to limit the maximum ground fault current. Without the grounding impedance, generator ground fault currents are generally higher than the level that the generator can withstand. The variability of ground fault current and the use of resistance grounding require special ground fault protection schemes.

- When a fault occurs near a generator, the voltage at the generator terminals tends to collapse. The current will decay according to a decrement characteristic specific to the generator. Current will decay from an initial value of six times full load current or more to a sustained value of three times full load current or less, possibly less than rated full load current. The magnitude of the sustained fault current and how long it can be sustained depends on the characteristics of the excitation system. The decaying current characteristic means that conventional overcurrent relays may not provide suitable protection. [7]

Some general characteristics of generator protective relays and settings are as follows. More detailed information can be found in references [7] and [8].

- *Differential:* As sources of power, generators are critical equipment and demand high speed, sensitive protection. Like other rotating machinery, a fault in a generator winding can result in extensive damage to both the winding and the steel core, requiring an extended outage for repair and possibly destroying the machine. Differential relaying is the main protection applied to large generators. Separate differential ground protection may also be applied. Differential relays may provide dual slope characteristics to achieve good sensitivity when fault current magnitude is low and good security when fault current magnitude is high. Slope characteristics might be as low as 5-10 percent for low currents and 50 percent or higher for higher currents. An alternate scheme used on smaller generators is known as a self-balancing scheme. Leads from both ends of a winding are passed through a current transformer with an instantaneous overcurrent relay connected to the CT secondary terminals. Three CTs are required for a three-phase generator and the CT must be large enough to accommodate the generator leads. Under normal conditions, the current into the winding equals the current out of the winding and the relay current is zero. Any measured current represents a fault in the winding.

- *Overcurrent:* Overcurrent relaying can provide backup protection for differential relays and protection for faults external to the generator. Special overcurrent relaying with either voltage control or voltage restraint is typically used. With a voltage-controlled relay, the overcurrent function is inoperable unless the voltage is below some settable threshold, such as 80 percent of rated. The voltage control feature allows the pickup setting to be less than full load current to provide reasonable sensitivity for the decaying fault current. A typical pickup setting might be 20-30 percent of the sustained fault current. With a voltage-restrained relay, the pickup setting is a function of the applied voltage. Typically, the setting defines the pickup at 100 percent voltage and pickup decreases to 25 percent of the setting at zero volts. Since the overcurrent function is operable at 100 percent voltage, the pickup is typically set at perhaps 150 percent of full load current.

- *Stator ground fault:* With the generator neutral connected to ground through a resistor, a ground fault results in phase to ground voltage appearing across the resistor. Either an overcurrent relay or an overvoltage relay can detect this condition. When the resistor is a low value so that ground fault current is several hundred amperes, an overcurrent relay typically is used. When the resistor is a high value so that current is limited to a just a few amperes, overvoltage relaying is typically used. A typical overcurrent relay pickup setting might be 1/2 -1/3 the current determined from the resistor rating. The voltage relay pickup is set as low as possible to allow fault detection for the largest possible portion of the winding. For faults near the neutral end of the winding, the voltage may be too low for detection. More elaborate schemes such as third harmonic voltage detection or current injection can be used to allow fault detection for the full winding.

- *Reverse power:* When input to a prime mover is lost, the reverse power to cause a generator to run as a synchronous motor can be a very small fraction of the generator rating. The following table shows minimum reverse power levels that indicate loss of a prime mover.[2]

Prime Mover	Motoring Power, % of Generator kW Rating
Condensing steam turbine	1%
Non-condensing steam turbine	3%
Water wheel	0.2%
Diesel engine	25%
Combustion turbine	50%

A reverse power relay must be very sensitive to detect the low power levels associated with reverse power to steam turbines and water wheels. For dependability, the relay should be capable of detecting a fraction of the power levels in the preceding table. Time delay of several seconds should be used to avoid undesired tripping for temporary power reversals.

- *Current balance protection:* Current balance relaying is applied to protect against unbalanced faults external to the generator. Like motors, generators are vulnerable to damage from heating caused by unbalanced current. Relays provide a trip time as a function of the unbalanced current squared. An adjustable factor determines the relay tripping time. Industry standards define the unbalanced current capability for generators and the settings are determined accordingly.

Other protective relaying functions are applied for faults and abnormal conditions specific to generators, including loss of field protection, field ground fault protection, abnormal frequency protection, loss of synchronism protection, and inadvertent energization protection. These functions are beyond the scope of this discussion.

Capacitor Protection

Power factor correction capacitor banks are made up of individual capacitor units connected in series and parallel groups to obtain the required voltage and kVAr ratings. Overall bank connections can be grounded wye, ungrounded wye, or delta. In some cases, a capacitor bank is split into two wye-connected sections. Each individual capacitor unit is protected by a small fuse. For smaller banks, protection for the bank is provided by power fuses. For larger banks, failure of individual capacitor units can cause remaining units to be subject to overvoltage which can lead to cascading failure of other units. The exact protection applied depends on the bank connection.

Some general guidelines for capacitor bank relay settings are as follows. More detail can be found in reference. [9]

- *Phase overcurrent:* For phase time overcurrent, a typical pickup setting is 135 percent of the bank rated current. Time delay should be set to coordinate with individual capacitor unit fuses. A suggested setting for phase instantaneous overcurrent is three times the bank rated current. If a second bank is connected to the same bus, transient inrush current that flows when a bank is first energized after being out of service will be higher than for a single bank, and an instantaneous setting of four times the bank-rated current is suggested.

- *Unbalance protection with overcurrent relays:* Capacitor banks with multiple units in series and parallel are designed to operate with a certain number of failed individual units. Unbalance protection is intended to operate when the unbalance becomes unacceptably high. For grounded wye banks, a residually-connected overcurrent relay provides protection for ground faults and also for failed units that result in unbalanced current. Pickup settings would be based on the calculated unbalance current as a function of the number of failed units. As with phase overcurrent relays, the time delay would be set to coordinate with individual capacitor unit fuses. For ungrounded wye banks, there are no coordination requirements and an instantaneous relay with a sensitive pickup setting can be used to provide ground fault protection. For split wye ungrounded banks, a time overcurrent relay can be installed in the neutral between the two bank sections. The pickup setting would be based on the unbalance current as a function of the number of failed units and the time delay would be set to coordinate with individual unit fuses.

- *Unbalance protection with overvoltage relays:* Overvoltage relays can be applied in several configurations for unbalance protection. For grounded wye banks, a current transformer can be connected between the capacitor neutral and ground with a secondary resistor and an overvoltage relay. For an ungrounded bank, a voltage transformer can be connected between neutral and ground with an overvoltage relay connected to the transformer secondary. For split wye banks, the neutral to ground voltage transformer arrangement can be used or a voltage transformer can be connected between the neutral points for the two sections with an overvoltage relay on the secondary. Pickup settings are based on the calculated voltage as a function of the number of failed units. A suggested maximum time delay is 0.3-0.5 second but should be greater than the clearing time of an individual unit fuse for a shorted unit.

- *Overvoltage:* Capacitor units are designed to withstand applied voltage according to the following table.[9][10]

RMS voltage, % of RMS rated voltage	Maximum Duration
110%	Continuous
125%	30 minutes
130%	1 minute
140%	15 seconds
170%	1 second
200%	15 cycles
220%	6 cycles
270%	1 cycle
300%	0.5 cycle

Overvoltage protection for the bank should be set with pickup and time delay based on the preceding capabilities. Sufficient time delay should be provided to allow the abnormal voltage to be corrected by operation of protective relays on other parts of the system.

Protection at the utility interface

If a water or wastewater facility operates local generation in parallel with the utility system, the utility may have specific requirements for protection at the service point. These requirements are intended to ensure safety of utility workers who may be working on lines and equipment subject to unexpected energization by the local generation. These requirements are also intended to avoid degrading selectivity and reliability of the protective devices installed on the utility system. Often, the basic requirement is to disconnect the local generation if a fault or abnormal condition occurs on the utility system. On the other hand, if the utility system suffers a fault or is in an abnormal condition, it may also benefit the water or wastewater facility to separate at the service point because the local generation may allow at least some processes to continue operation.

Some general requirements and guidelines for setting relays for utility interface protection are as follows.

- *Directional overcurrent:* Directional time overcurrent relaying for phase and ground should be set to detect faults at the next upstream zone in the utility system, for example the utility substation bus. More sensitive settings can be used, especially if the fault information for the utility system is not known, but detecting faults in zones deep within the utility system may reduce security at service point for the water or wastewater facility. Time delay should be set to allow for temporary current reversals associated with synchronizing and to allow utility system relays to clear remote faults. Suggested time delay is 2-5 seconds for remote faults.

- *Reverse power:* If the utility service agreement does not allow purchasing of power from a local generation, a reverse power relaying set to operate for power flow into the utility system may be desirable or required. Such protection can supplement directional overcurrent relays which may be more sensitive to the highly inductive current associated with faults than to power flow. A sensitive pickup setting with a 2-5 second time delay to allow for temporary power reversals can be used.

- *Voltage and frequency:* Normally, service voltage should be well within a tolerance of ±10 percent. Industry standards for service voltage suggest limits of ±5 percent. [12] If a utility system disconnects from a source of local generation, the voltage and frequency can be expected to sag as the local generation attempts to supply the large utility load. On the other hand, if a ground fault exists on the utility system, the voltage on the unfaulted phases will increase. If a large block of load is interrupted, generator output voltage will increase and an overvoltage relay may be applied as backup protection for the voltage regulator. Overfrequency is less likely to indicate separation from the utility system but may be applied to protect against a failure of the generator speed control system. Relay settings of 115 percent of nominal for overvoltage and 80 percent of nominal for undervoltage and time delay of 2-5 seconds for both functions should provide a good balance between dependability and security. Settings of ½ Hz above and below nominal with a 2-5 second time delay are suitable for frequency protection.

Conclusion

This paper has described the basic purposes of protective relay systems and has discussed the protective relaying concepts of speed, selectivity, reliability and zones of protection. The main types of protection applied to water and wastewater systems are overcurrent, directional overcurrent, voltage and current balance, voltage, frequency, directional power, and differential. These types of protection are implemented in relays designed for major equipment such as transformers, switchgear buses, motors, generators and power capacitors. The utility service point may also need special attention with respect to protection if the water or wastewater facility operates local generation. General characteristics of each type of protection have been discussed, as well as some guidelines for applying protection to specific types of equipment. Motors for pumping applications are critical to water and wastewater facility operations and the major faults and abnormal operating conditions affecting motors also have been addressed. The guidelines discussed are intended to give a general understanding of some of the factors to be considered in applying and setting protective relays. More detailed information is available in the cited references.

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About the Author

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