Best Practice Catalog

Generator Switchgear

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1.0 Scope and Purpose

The document for the generator switchgear addresses its technology, condition assessment, operations, and maintenance best practices with the objective to maximize the unit performance and reliability. This best practice is limited to medium voltage (MV) generator breakers and associated switchgear when connected between the main generator terminals and the low voltage generator step-up (GSU) windings. Unit connected generators utilizing high voltage (HV) breakers are not included.

The primary purpose of the generator switchgear is to provide load switching (synchronizing the generator to the system) and fault interrupting capabilities. The switchgear includes the switching or interrupting device (breaker) and associated enclosure, buswork, control, and instrumentation. The switchgear may also include metering and protective devices.

The manner in which the generator switchgear is designed, operated, and maintained can significantly impact the reliability of a hydropower unit.

1.1 Hydropower Taxonomy Position

Hydropower Facility → Powerhouse → Power Train Equipment → Generator Switchgear

1.1.1 Generator Switchgear Components

Switchgear is a general term that in this application refers to the interrupting devices that control and protect the flow of the generator output power. These devices include the circuit breaker and may include instrument transformers, control devices, and surge protection. The circuit breaker, depending on the type and vintage, may be freestanding or installed in metal clad switchgear which has the following characteristics as defined by ANSI [11]:

- Switching and interrupting devices are removable
- Energized parts are compartmentalized
- Compartments are isolated from each other
- Medium voltage bus is insulated
- Accessible from front and rear
- Shutters isolating the breaker compartment from the live bus when the breaker is withdrawn are required

Figure 1: Typical Switchgear

Figure 1 shows a typical indoor switchgear line-up with the breaker removed from its compartment.

Arc resistant switchgear, designed to withstand the effects of an internal arcing fault, has been developed and is offered by some manufacturers.

Breaker: The primary component of medium voltage switchgear is the circuit breaker. The main function of the breaker is to either connect or disconnect the generator to the system through the GSU or to interrupt generator or system sourced fault currents. The breaker may be an oil, air-magnetic/air blast, vacuum, or Sulphur Hexaflouride (SF_6) type depending on the arc interrupting medium and technology.

Oil circuit breakers were among the first breakers implemented and are primarily used in outdoor applications. Although they were discontinued in generator breaker applications starting in the 1940's, they may still be found in older hydro plants. Oil circuit breakers have contacts located in an oil tank with an operating mechanism usually located outside the tank.

Air-magnetic or air blast breakers utilize a combination of one or more of the following techniques for fault interruption: 1) high pressure air blast, 2) arc elongation, 3) arc constriction, 4) arc restraining metal barriers, or 5) magnetic blowout. These techniques are used to extinguish the arc resulting when the contacts separate (breaker opens). These breakers are spring operated and usually installed in metal clad switchgear. They are completely removable for maintenance, testing and inspection. Rack out breakers may connect either vertically or horizontally with the main bus.

Vacuum breakers employ contacts in a vacuum bottle with a near perfect vacuum to interrupt current flow. The contact geometry can vary, based on the application, to reduce contact wear, improve arc interruption at zero current, and to reduce pre-strike and restrike occurrences. The current carrying contacts are not accessible on these breakers. Figure 2 shows one phase of a medium voltage sealed vacuum interrupter.

Figure 2: Vacuum Circuit Breaker Interrupter

SF_6 utilizes design concepts similar to vacuum circuit breakers except the contacts are inside a bottle filled with sulphur hexafluoride for arc extinguishing. Modern SF_6 switchgear typically houses the bus and circuit breaker in the SF_6 medium resulting in a compact and arc resistant assembly. SF_6 breakers may be freestanding or installed in metal clad switchgear.

In 1989 the IEEE [6 and 7] first developed a standard recognizing the significant differences between standard distribution class breakers and true generator breakers. The purpose of the document was to set standards required by the severe operating conditions for generator circuit breakers. The current interruption basis of an ordinary distribution short circuit type breaker is that for relatively short time increments the symmetrical short circuit current has a constant value with a direct current (DC) offset determined by circuit conditions at the time of the fault. This DC component, or offset, has a rate of decay determined by the system reactance (X) to resistance (R) ratio (X/R). Both IEEE and ANSI define this ratio as 17 for distribution applications with a time constant of 45 ms; whereas, in a generator application the ratio is much higher due to the generator and transformer reactance. Ratios of 50 or more with a time constant of 133 ms are common for generators. This means that the DC component of current in a generator application at the instant of interruption is much larger than it would be in a distribution application. Another significant difference is the potential for a transient recovery voltage (TRV) across the interrupter contacts. In a generator application, this is 3 to 4 times higher than it would be in a distribution class breaker. Also, as a generator is brought to frequency and voltage in preparation to synchronize, there are instants when the voltage across the open breaker contacts can theoretically be 180 degrees out of phase.

<u>Instrument Transformers</u>: These transformers are typically included with the generator switchgear or installed on the generator bus external to the gear. They reduce the medium voltage and high currents to low values usable for metering, relaying, and regulating circuits. Voltage is transformed or “stepped-down” by the potential (PT) or voltage (VT) transformer. The primary winding is usually connected line-to-line or line-to-neutral and is isolated from the secondary control circuits which are normally 120 VAC. The PT’s

should be a drawout-type with current limiting fuses on the primary. The current transformer (CT) is often a toroid (doughnut) type where the primary winding, or generator lead, passes through the center or it may be a busbar type where a section of the generator bus forms the primary winding. CT ratios should be selected to coordinate with their associated protective devices and should be adequate for steady state normal load currents as well as fault currents. The CT should have a mechanical rating equal to the momentary rating of the switchgear and be insulated for the full voltage rating. Both PT and CT accuracy / burden selection should be based upon the application and loads served (relaying and/or metering).

Surge Protection: Capacitors, surge arrestors, or both may be included to protect the insulation of the generator. The best practice is to install surge protection at the generator terminals although it is common that these devices be included in the switchgear or be installed on the external bus. Outside units or units with outside bus arrangements should be provided with surge protection designed to maintain voltage surges below the insulation level of the protected equipment.

Auxiliary Cooling: Supplemental cooling may be included to achieve the required ratings while maintaining prescribed temperature limits.

Buswork: Aluminum or copper busbars (or cable) may be used to connect the line and load sides of the breaker. In metal clad switchgear this bus will be insulated. Buswork and cables must be rated for the voltage, continuous, and momentary ratings of the breaker.

1.2 Summary of Best Practices

1.1.1 Performance/Efficiency & Capability – Oriented Best Practices

- Periodic verification of torque for bolted bus connections.

1.1.2 Reliability/Operations & Maintenance Oriented Best Practices

- Circuit breakers need periodic exercise. If the breaker remains open or closed for 2 months or more, it should be opened and closed several times to verify smooth operation.
- Instrument transformer accuracy and burden ratings shall be adequate for the relaying and/or metering loads they serve.
- Inspect circuit breakers after severe fault interruptions
- All openings should be sealed against weather or vermin intrusion.
- Breakers should have trip circuit monitoring and either redundant trip coils or a breaker failure scheme to trip upstream breakers depending on the plant configuration.
- Verify circuit breaker ratings are adequate for updated capacities and fault.

- Remote racking devices should be provided and utilized as a safety feature for operations and maintenance personnel.

1.1.3 Best Practice Cross-references

Electrical – Generator Best Practices

2.0 Technology Design Summary

2.1 Material and Design Technology Evolution

Original applications have been dominated by oil and air interrupting technologies. The primary disadvantages of these technologies are that they are both bulky and require high maintenance. The disadvantages and requirements for higher ratings led to the later development of first SF_6 and then vacuum technologies. Each interrupting technology described above has followed its own time-line as manufacturers continued to refine the product for higher capacity, reliability and reduced physical size. Air and oil technologies have been replaced by vacuum and SF_6 over a 40 year period starting in the early 1970's.

In the oil-type circuit breaker, the interrupter is immersed in insulating oil as the arc quenching medium. This was a dominate circuit breaker type until the 1960's. In this design, contacts are configured and timed so that the pressure generated by the arc at the initial separation point forces oil through a secondary contact to both cool and extinguish the arc. Although there are variations on the design of oil circuit breakers, all use this principal for fault interruption. Flammability, environmental, and high maintenance factors are some disadvantages of the oil circuit breaker.

Early air circuit breakers were simply plain break switches which stretched the arc between a set of stationary and movable contacts with no arc control. Consequently, arc times were long, contact wear was high, and ratings were limited. Performance was improved by the inclusion of arc control devices with the arc chute being the most common device. Air blast or air magnetic type circuit breakers use air as the dielectric and arc quenching medium. While simplicity of design, ease of inspection, and relatively low initial cost are advantages of the air-type; and high maintenance and use of air as an insulating and extinguishing medium are disadvantages. Another disadvantage of both air and oil type breakers is that as these types have been supplanted by the SF_6 and vacuum technologies, locating replacement parts and servicing has become difficult.

SF_6 breakers were first used in the United States in the early 1950's. Puffer-type, where the relative movement of a piston and cylinder is used to generate a compressed gas for arc extinction, was introduced in 1957. Since that time, developments in SF_6 breaker technology have made them more robust, quieter, and more reliable than some of the other technologies. As the contacts in the puffer-type (single pressure) SF_6 breaker separate, the difference in pressure between the hot gas (caused by the arc) and the cool gas causes a flow that cools the breaker pole and sweeps the arc from the contacts. In earlier SF_6 breakers, a blast of high pressure gas from a pressurized tank was used to extinguish the arc. While SF_6 itself is non-toxic, the by-products created by arc interruption are considered toxic. Also, SF_6 has been identified as a green house gas and therefore potentially an environmental concern.

Vacuum interrupters became available in the early 1970's. An advantage of the vacuum interrupter technology is that the arc is maintained at a minimum since there is nothing in the extinguishing medium (except contact material) to ionize and the vacuum itself is a superior dielectric. Contact erosion is minimal. Vacuum circuit breakers have lower mechanical requirements due to their smaller size and shorter stroke and are simpler in design than the other technologies.

2.2 State of the Art Technology

As previously mentioned, SF_6 and vacuum technologies are now preferred for their many advantages over oil and air type circuit breakers. Manufacturers continue to make improvements to both SF_6 and vacuum breakers.

An increased interest in personnel safety has lead to the recognition of arc flash hazards associated with medium voltage switchgear by OSHA, NFPA and IEEE. Each of these organizations has addressed the concerns by developing standards governing arc flash hazards [13, 14, 15, and 16]. IEEE defines accessibility types of arc resistant gear with Type 1 and Type 1C having arc resistant features at the freely accessible front of the equipment and Type 2 and 2C include these features on all sides. The "C" indicates the inclusion of arc resistant features between adjacent compartments. Arc resistant switchgear includes more robust construction to contain the fault energy, special venting to also contain the fault energy and channel the exhaust gas, and closed door circuit breaker racking and operation features. Venting of the exhaust (arc energy) should be such that it will not present a personnel hazard or jeopardize other equipment. While arc resistant switchgear may certainly play a role in providing a safer employee workplace and represents a "state of the art technology" when applied in conjunction with proper training, job planning and tools, it is currently not a requirement of any governing authority.

As previously mentioned IEEE standards [6 and 7] now recognize the distinction between distribution class and generator class circuit breakers. In practice, a "generator" circuit breaker must be able to withstand phase displacements prior to synchronizing and following trips, withstand transient recovery voltages not seen on normal distribution systems, break strong and highly asymmetrical fault currents (delayed current zeroes), and withstand continually high load currents.

3.0 Operation & Maintenance Practices

3.1 Condition Assessment

In addition to the visual inspections and tests performed as routine maintenance, a number of other factors are considered to assess the breakers. The assessment should consider the age, number of operations, history, and type of environment. The United States Army Corps of Engineers (USACE) [3] provides a very detailed, multi-tiered approach to the assessment of generator circuit breakers. While this assessment considers technological factors in the scoring, overall assessment and scoring contained herein provides a methodology to use when the detailed information required by the USACE guide may not be available.

Electrical testing constitutes one facet of the condition assessment. Testing should be performed per the manufacturer's guidelines regarding method. Frequency of testing will be determined by the manufacturer's recommendations and operating experience. For example, depending on the severity of the fault, breakers should be considered for inspection following fault interrupting duty. Breakers that are cycled multiple times during a 24 hour period should have operating mechanism inspections more frequently than those operated on a weekly basis. For the electrical test, manufacturers will provide specifications for insulation resistance (rule of thumb is 1 megohm per kV + 1 megohm), contact resistance, and timing. Hi-potential testing confirms suitability for operation at rated voltages and can be used to ensure vacuum interrupter bottles have maintained their vacuum. Breaker control checks should include verification of trip and close at minimum control voltage.

The condition assessment should evaluate the breaker's interrupting current rating against the maximum available fault current. As originally supplied, the breaker most likely had extra capacity to allow for system growth. Changes in system conditions, generator step-up transformer impedances, or unit capacity may have increased available fault current to a point that may exceed the breakers rating. If the current available fault current exceeds the breakers capacity, failure of the breaker and excessive collateral damage is possible. In this case, corrective action to increase the breakers capacity or decrease available fault current is required.

3.2 Maintenance

Maintenance requirements are largely influenced by the service duty, complexity of design and operating environment. Because of wide variations in these factors, each operator should develop maintenance schedules based on operating experience and the manufacturer's recommendations. Maintenance recommendations for each type of breaker will vary due to design details and manufacturer. Basic maintenance should include the following:

- Check the operating mechanisms of all types of breakers for freedom of movement, wear, and proper lubrication as recommended by the vendor.
- Racking devices, if applicable, should be checked for wear and freedom of movement.
- Check auxiliary position switches (MOC and TOC) for actuation and continuity.

- Check electrical sliding and pressure-type contact points for continuity.
- Perform visual inspection of switchgear components for obvious defects.
- Ensure all electrical connections are tight. Perform infrared scans, if possible, of bolted and plug in connections.
- As with all electrical devices for all types of breakers, cleanliness is essential.
- Both indoor and outdoor switchgear and breakers should have physical barriers (screens, filters, etc.) to prevent intrusion by vermin and environmental contaminates.
- Thermostatic controls should be verified for function.

Oil circuit breakers are unique in that the interrupting medium, oil, is subject to deterioration every time the breaker operates with load; therefore, requiring periodic quality testing and refurbishment or replacement. Main and arcing contacts require inspection and are subject to more wear than either SF_6 or vacuum breaker contacts. Since their contacts are immersed in oil, they are not visually accessible during routine maintenance. Contact engagement may be determined by measuring the travel of the operating mechanism. In addition to the aforementioned, inspection for leaks is required. These breakers are usually freestanding (i.e. not metal enclosed or metal clad).

Air magnetic and air blast breakers are both air insulated. Air blast breakers use high pressure air to operate the breaker and extinguish the arc and may not be removable for maintenance. For both air insulated breakers, the main and arcing contacts require periodic inspection. All components of the operating mechanism should also be checked for proper operation, lubrication, excessive wear, and missing or broken hardware. The pressurized air system of the air blast breaker should be inspected and tested per the manufacturer's recommendations and as a minimum any leaks should be identified and repaired.

Vacuum breakers typically require less maintenance than the other types. As with SF_6, the interrupters are sealed so no contact cleaning is necessary (or required) since the arc is interrupted in a vacuum. Normally the operating rod is scribed with a mark whose position with the contacts closed is noted and compared to a reference. These breakers usually have fewer operating parts and operate at lower forces than the other types, and are therefore likely the most reliable. Some manufacturers consider their vacuum breakers to be maintenance free during an operational life of 10,000 switching operations.SF_6 load contacts will not normally be accessible but contact engagement may be determined by travel of the operating mechanism. Practical experience with SF_6 has shown that sealed interrupters may not require servicing and are typically suitable for as many as 50 short circuits (depending on severity) and several thousand full load interruptions before replacement is required. Continuous cast epoxy envelopes and special seals have almost eliminated any maintenance requirements for the interrupters. It should be noted that high temperature decomposition of SF_6 gas leads to the generation of toxic byproducts. If powdery substances are encountered during maintenance of SF_6 breakers or interrupters, they should not be inhaled or handled.

4.0 Metrics, Monitoring and Analysis

4.1 Data Analysis

Reliability data to analyze includes all electrical test data collected and comparisons to the manufacturer's specification. If performed regularly, the data can be trended, especially contact resistance and contact open/close timing tests.

A comparison of available short circuit current with the breakers interrupting capability should be made. To accomplish this, an up-to-date short circuit study must be available and the circuit breaker interrupting rating known. The circuit breaker rating methods have evolved from rating the breaker on a "total" current basis to a symmetrical current basis for newer breakers. "Total' current included the DC offset of the AC symmetrical current. The standards using this rating basis have been superseded although there are probably still breakers in service that carry these ratings. Newer standards consider the rated short circuit current as the highest value of the symmetrical component of the short circuit RMS of the current envelope. In the event a breaker rated on a total current basis is replaced, a conversion to the rated symmetrical current basis is performed as follows:

Note: This conversion should be approved by the prospective supplier.

Rating based on symmetrical current = Total current rating x [nominal voltage/rated maximum voltage] x F

F = 0.915 for a 3 cycle breaker

= 0.955 for a 5 cycle breaker

= 1.0 for an 8 cycle breaker

4.2 Integrated Improvements

Vacuum and SF_6 type circuit breakers offer numerous advantages over air and oil type circuit breakers. These technologies offer smaller size, higher reliability, and reduced maintenance cost. The most critical improvement is to ensure that the capacity of any breaker should offer some margin over the expected worst case fault current. Any changes to the power system made since the installed breaker was specified may challenge its interrupting capacity and should be analyzed. The required capacity can be realized with any of the types discussed in this BP. Modernization or upgrade of the switchgear may be accomplished either by a complete replacement or a retrofit of existing switchgear with new circuit breakers (interrupters).

5.0 Information Sources

Baseline Knowledge:

1. Siemens, *Tech Topic No. 71, Generator Circuit Breakers*
2. Siemens, *Tech Topic No. 72, Generator Circuit Breakers*
3. USACE, Hydro Plant Risk Assessment Guide, *Appendix E2, Circuit Breaker Condition Assessment*
4. TVA, *Design of Projects Technical Report No. 24 Electrical Design of Hydro Plants*
5. Electric Power Research Institute, *Power Plant Electrical Reference Series, Vol. 7, Auxiliary Electrical Equipment*

State of the Art:

1. *Energy Tech Article Hydroelectric Power Station Nears Completion of Challenging Switchgear Project, June 2009*
2. *17th Annual Conference on Electricity Distribution, Vacuum Interrupters for Generator Circuit Breakers, They're Not Just for Distribution Circuit Breakers Anymore", May 2003*

Standards:

6. IEEE, STD C37.013 *Standard for AC High Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis*
7. IEEE, STD C37.013a *Standard for AC High Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis – Amendement 1 : Supplement for Use with Generators Rated 10-100 MVA*
8. IEEE, STD C37.010 *Application Guide for AC High Voltage Circuit Breakers Rated on a Symmetrical Current Basis*
9. ANSI, C37.06 *AC High Voltage Circuit Breakers Rated on a Symmetrical Current Basis-Preferred Ratings and Required Capabilities*
10. ANSI, C37.20.7 – *IEEE Guide for Testing Metal Enclosed Switchgear Rated Up to 38 kV for Internal Arcing Faults*
11. ANSI, C37.20.2 – *IEEE Standard for Metal Clad Switchgear*
12. ANSI, C37.04 – *IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*
13. IEEE Std C37.20.7 *Guide for Testing Metal-Enclosed Switchgear Rated Up to 38 kV for Internal Arcing Faults*
14. OSHA 29 *Code of Federal Regulations (CFR) Part 1910, Subpart S*
15. NFPA 70E, "*Standard for Electrical Safety Requirements for Employee Workplaces"*
16. IEEE 1584, *Guide for Arc Flash Hazard Analysis*

It should be noted by the user that this document is intended only as a guide. Statements are of a general nature and therefore do not take into account special situations that can differ significantly from those discussed in this document.

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