The acceleration system is a variable frequency converter (SFC) that is shared between two units. Three acceleration configurations are possible as shown in Fig. 1. They are: conventional, cross-feed and back to back configuration. The latter two configurations are seldom used. Fig. 1 shows machine 2 as it is being accelerated. The SFC arrangement is symmetrical, therefore the configurations of machine 1 is a mirror image of Fig. 1.

With conventional and cross-feed configuration the SFC accelerates machine 2. Back to back acceleration is used when the SFC is not available. Machine 1 and 2 are configured as a synchronous generator and motor respectively. Machine 1 is accelerated with excitation using the hydro turbine. It provides electrical power with an increasing frequency to accelerate machine 2 as a synchronous motor.

A paralleling device (synchroniser) monitors voltages on either side of the load switch. Near synchronous speed (pump or generate mode) it starts to control the machine speed and voltage and closes the load switch at synchronous conditions. The machine is now connected to the grid. If the machine is in pump mode the turbine is flooded to commence pumping water to the upper dam. If it is in generate mode it uses the upper dam water to generate electricity as it flows into the lower dam.

The protection and synchronising application at a pumped storage plant has more considerations compared to a conventional generation plant. It must also accommodate the following:

- SFC transformer protection
- Frequency variation during acceleration,
- Effect of reversing isolators
- Absence of a generator LV circuit breaker
- Motor synchronising functionality

Instrument transformer locations and protection functions

With the upgrade the existing instrument transformers are re-used. The static protection that requires the use of interposing is replaced with modern numerical protection. Modern numerical protection allows the flexibility to remove the interposing current transformers. Fig. 2 shows the important current and voltage transformer (CT and VT) locations. Although single CTs is shown they are fully redundant. An important design criterion is that secondary CT wiring are not switched but accommodated in the intelligent electronic device (IED) software. Control and secondary VT signals are allowed to be switched.

Fig. 2 indicates the instrument transformers location. The important protection functions and associated instrument transformers are listed in Table 1.

Protection implication of SFC operation

In pump mode the machine operates as a synchronous motor. The rotation is opposite to that of the generate direction to use the turbine to pump water to the upper dam.

A synchronous motor cannot be started direct-online and the SFC is required to perform a ‘soft start’. The load switch is open with the SFC breakers closed to bypass the open load switch. The SFC accelerates the excited machine by energising the stator with voltage with an increasing frequency (up to 50 Hz). Once the motoring machine is synchronised the SFC is stopped and its breakers opened. It is used again on this machine for braking during the shutdown sequence. The turbine can be loaded for pumping or continue to spin unloaded in synchronous condense mode.

Differential protection schemes

A differential protection scheme, will mal-operate if differential current are calculated at different frequencies. During SFC operation the CTs of the generator and generator transformer differential zones are not always the same.

Fig. 3 shows the generator transformer...
differential zone, current path and terminal CTs during conventional SFC operation (braking and accelerating).

It is a four terminal differential scheme. The CTs on the transformer-side of the load switch operates at 50 Hz but the generator-side CT frequency follows the SFC output. However the generator-side CT current is zero during SFC operation because the load switch is open and bypassed. Therefore the generator transformer differential protection remains stable and operates at 50 Hz. When the load switch closes, current starts to flow through the load switch and the generator side CT. The two systems are now tied via the load switch and all the currents are at the same frequency at 50 Hz. The SFC is stopped and machine and line side SFC breakers are opened which does not affect the generator transformer differential protection reliability.

The generator differential protection is a three-terminal scheme. During SFC operation the transformer-side load switch CT operates at 50 Hz but the neutral- and machine side SFC CTs follows the SFC output frequency (Fig. 4). With the load switch open and the SFC in operation, the current through the transformer-side load switch CT is zero and does not affect the protection stability. The difference (compared to the transformer differential) is that the generator differential protection must be reliable and follow the frequency ramping to 50 Hz. It is practically not possible to have the generator differential function active and reliable as soon as SFC operation commences (0 Hz). This is because of the low frequency limit of the protection IED is around 6 – 10 Hz. Furthermore the CTs at the differential terminals are different (ratio, make, class). Their performance at reduced frequencies and current is unknown and the resulting differential error could be the limiting factor. The limit of operation will be determined during commissioning and the function is inhibited below the limit.

At frequencies lower than the limit one has to rely on other means of protection, such as the SFC protection and perhaps peak sensing overcurrent.

The SFC uses two 27 MVA three-winding transformers installed at the line- (rectifier) and machine-sides (inverter) respectively. The SFC transformers CT arrangement results in four-terminal differential schemes to be implemented at both transformers. Fig. 5 shows the machine- and line side transformer differential protection zones. The line-side differential protection current terminals always operate at a fundamental of 50 Hz, any harmonics are rejected.

All four machine-side differential protection current terminals follow the SFC output frequency. This differential function must track the fundamental frequency of the voltage applied to the machine stator and reject any harmonics.

During SFC operation (acceleration and braking) only two circuit breakers are closed at any time for any of the acceleration modes shown in Fig. 1. Usually the conventional configuration is used. SFC fault isolation is simplified if all four SFC breakers are tripped for machine-, or line side faults. The SFC and AVR controllers must be stopped or tripped. Stop refers to the preferable case where the SFC or AVR shuts down subsequent to dissipating any stored energy – providing the delay is not excessive. Trip implies the
protection tripped the (field) breaker(s) without cognisance of the SFC and AVR controller’s ability to perform emergency shutdowns. The isolating devices might open sooner but could result in over-voltages, arcing and excessive equipment fatigue.

Fig. 6 shows the devices to be opened (black arrows) for line, and machine side faults as indicated.

Tripping all four SFC breakers clears a line and machine side faults effectively. It also allows the generator transformer to remain energised.

Should a SFC breaker-fail occur all possible energy sources must be isolated. For the conventional configuration, a line-side breaker fail trips the associated 400 kV generator and 3,3 kV station board circuit breaker (Fig. 7).

With the cross-feed configuration the adjacent 400 kV generator and 3,3 kV station board circuit breakers are tripped to isolate the fault. It is seldom used, only when the line side system of the machine to be started is compromised. Pre-fault current through the line-side CTs provides better discrimination for identifying which side to trip for a line side breaker fail monitoring.

To identify which the . It will correctly identify the 400 kV source for conventional and cross feeding. If the line-side breakers are open and a fault occurs between a CT and breaker, it would still identify the 400 kV source. It isolates the 400 kV only after the breaker-fail time expired, which is too long. It can be cleared faster if a high set “instantaneous” overcurrent element is used. The overcurrent level should be set higher than the maximum SFC load. Breaker statuses must be used in conjunction with the pre- and fault current monitoring for cases where the fault current is removed but the breaker has failed. For example if a machine-side breaker fails (stuck breaker) it is unlikely to be identified by the protection if only current monitoring is used. All the possible in-feeds are isolated with the initial fault clearance. Only the line side SFC breaker, the SFC and AVR are tripped. This effectively removes the in-feed from the machine, the SFC and the source to the SFC. Since the fault current is zero breaker, fail is not initiated. If the breaker status was used, breaker fail would have been initiated. The next devices to trip would have been the AVR and line side breakers. These however are already open as per the philosophy to trip all the breakers, SFC and AVR.

In back to back mode the SFC does not operate but the protection is active. Both machine-side breakers are closed. A fault shown in Fig. 8 is cleared already when the two machine side breakers are tripped. Since the load switch and line-side breakers are already open there cannot be an in-feed from the line side.
By tripping the four SFC breakers, the SFC and both AVR's the fault is cleared and a breaker fail scenario does not result in slower fault clearance.

Cross-feed and back-to-back configurations are rarely used and it is anticipated that the outage duration subsequent to a fault occurrence will be longer than normal to determine the fault location and perform analysis.

Effect of reversing isolators

When the machine is generating the hydro turbine and water provides the rotating force that spins the electrical machine to generate electricity. The turbine can only turn in one direction when the water flows from the top to the bottom dam. The electrical phase rotation in this instance must be the same as the electrical network to deliver power to the grid.

To act as a pump the electrical machine provides the rotating force but the turbine rotation must be opposite to that of the generating direction. Since the turbine is directly coupled to the synchronous machine the latter must also change direction which is performed the classical way by physically swapping two phase connections to the machine stator with the use of reversing isolators (Fig. 9). At Palmiet the L2 and L3 phases are swapped as shown in Fig. 9. This phase rotation swap must be accommodated in the protection application.

The generator differential protection is affected because phase-rotation at the neutral side CTs change between modes. Incorrect phase currents will be compared to the terminal side CT when
the machine is in pump mode resulting in an incorrect trip.

An important design requirement is that the secondary CT currents cannot be physically switched. The problem is solved with the modern protection IEDs by performing the reconfiguration internally. One such concept is shown in Fig. 10. The CTs are permanently wired to the IED. Two analogue processing modules are configured for the neutral side CT set to accommodate the rotation change. The outputs of both these modules are combined and connected to a terminal of the differential module (87 G). The reversing isolator position enables the appropriate analogue processing module. The remaining CTs of the differential zone is connected to the other terminals of the 87 G module.

Other protection functions that rely on current and voltage sequence components that can be at risk to mal-operate are negative phase sequence protection and fuse fail protection. Impedance and power functions supplied by the generator voltage and neutral currents that are compared on a per phase basis are fine because both are swapped in pump mode.

**Load switch and HV breaker control**

A load switch as opposed to a breaker was installed for economic reasons at the time of construction. A subsequent feasibility study did not warrant replacing the load switch with a circuit breaker. The implication is that for an electrical fault the protection always trips the HV breaker isolating a larger area than would have been the case if the load switch was a breaker. As a consequence the 3.3 kV station boards are de-energised that are required to shut the machine down. Although the unit is able to shut down without the station boards during an emergency it places undue stress on the unit.

The synchroniser issues close commands to the load switch and 400 kV CB. The load switch is closed during generate- pump- and black starting but different functionality is required. The synchroniser also supervises closing of the 400 kV CB during black starting and back-energising. The plant status before back-energising the generator transformer is: the 400 kV breaker is open, the load switch, SFC breakers and station board breaker are open. Prior to closing the 400 kV breaker the synchroniser confirms the gen transformer side VT to be de-energised by performing a live 400 kV bus, dead line check. The reversing isolators can be in any position. A generate start sequence transfers the reversing isolators to the generate position, accelerate the turbine by controlling water flow (guide vanes), apply excitation and use the synchroniser to control the governor (speed) and voltage (automatic voltage regulator – AVR) and parallel the machine to the grid by closing the load switch when the synchronising conditions are satisfied.

A pump or pump-condense start sequence transfer the reversing isolators to pump position and start the SFC operation. The selected SFC breakers close and the rotor excited with the AVR satisfying the over-fluxing criterion. The SFC applies a voltage with increasing frequency to the machine stator accelerating the turbine. Near synchronous speed the synchroniser adjusts the speed and voltage by sending controlling pulses to the SFC and voltage (AVR). It parallels the machine to the grid by closing the load switch when the synchronising conditions are satisfied. Prior to a black start sequence the 400 kV and load switch breakers are open and the 400 kV busbar is ready to be energised. The black start sequence transfers the reversing isolators to the generate position and the de-energised machine is accelerated by opening the guide vanes. Near rated speed the load switch is closed provided the synchroniser confirms the running and incoming VTs adjacent to the load switch are de-energised. Once the load switch is closed excitation is applied and the generator transformer is energised. The excitation ramp rate moderates transformer inrush effect. The operator energises the 400 kV bus by closing the 400 kV generator breaker provided the synchroniser confirms the 400 kV bus VT is de-energised (live line, dead bus check).

**Acknowledgement**

This article presented at the 2012 SA Power Systems Protection Conference in Johannesburg in November 2012, and is republished with permission.

Contact David van der Merwe, Eskom, Tel 021 941-5909, vdmerwd@eskom.co.za