ADVANCED TECHNICAL QUESTIONS AND ANSWERS

- Power System Protection
- Testing Commissioning
- GIS Substation
- FAT SAT Energization
- On-Load Verification

Total Questions: 112 | Total Sections: 21

Source: Commissioning Manual 2025

Standards: IEC 62271 • IEC 61869 • IEC 60255 • IEC 61850 • IEC 60270

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SECTION 1 Commissioning Fundamentals

Q01. What are the two main reasons for doing commissioning tests on site?

ANSWER The first reason is to confirm the equipment was not damaged during transport, was installed correctly, and works as it should once energized. The second reason is to collect baseline test data that can be compared with future maintenance results to spot any equipment deterioration over time.

Q02. What is the difference between acceptance testing and routine maintenance testing when it comes to the test voltage used?

ANSWER Both use the same types of tests, but the voltage applied is reduced to avoid stressing older insulation. Acceptance tests use about 80 percent of the factory test voltage. Routine maintenance tests use about 60 percent of the factory test voltage. This is because older insulation cannot handle the same stress as new equipment.

Q03. List five checks that must be done during the Pre-Energization Inspection before a circuit is energized.

ANSWER Any five of the following: Verify circuit naming and labeling. Check that equipment phase connections match the phasing diagrams. Confirm no violations of required safety clearances. Check that all CT links are correctly placed in their normal positions. Verify correct relay settings have been applied. Confirm removal of all test connections. Check battery supplies are in good condition and charged. Check insulation resistance of power cables and other equipment. Ensure all cable terminations are tight. Confirm proper earthing of all equipment.

Q04. What must be done during Post-Commissioning Inspection before handing over equipment for normal service?

ANSWER The following must be confirmed. All temporary commissioning equipment has been removed. CT links are correctly set to their normal operational position. All selector switches and tap changers are in correct positions. All relay settings have been restored to standard operational values. General visual inspection confirms overall readiness. Commissioned equipment is clearly identified to prevent accidental interference.

Q05. What two separate documents must be prepared for proper commissioning records?

ANSWER Two documents are required. First is the Commissioning Report, which is the official management record. It includes a work program with completion dates, a list of all commissioning tests, and a completion certificate signed by the team leader. Second is the Commissioning Log, which is the technical record containing completed test schedules, test certificates, inspection reports, and other technical documents.

SECTION 2 Insulation Resistance Testing

Q06. What is Insulation Resistance and how is it calculated?

ANSWER Insulation Resistance is the resistance of insulation between two conducting parts, or between a conducting part and earth. It is calculated as IR equals Vdc divided by It, where Vdc is the applied DC voltage and It is the total current through the insulation.

Q07. What is the minimum acceptable IR value for CTs, VTs, and Circuit Breakers according to NEDC standard practice?

ANSWER The minimum acceptable IR value per NEDC standard practice is 1 GΩ (1000 MΩ). If the measured value is below this, the result must be compared with factory test reports. Low readings are often caused by moisture, and the equipment should be dried and retested before any further action.

Q08. What test voltage is used for CT IR testing?

ANSWER Between the CT primary winding and any other terminal, the injection voltage is 5 kV DC. Between CT secondary windings and secondary-to-earth, the injection voltage is 500 V DC.

Q09. Why must the CT neutral be removed from earth before performing an IR test?

ANSWER If the neutral is earthed during the test, the test voltage will flow to earth through the earth connection instead of through the insulation. This gives a false low reading, making the insulation appear worse than it is, or simply bypasses the test entirely. The neutral must be removed so the full test voltage stresses only the insulation being tested.

Q10. What is the most common cause of a low IR reading, and what should be done before dismantling the equipment?

ANSWER The most common cause is the presence of moisture in the insulation. Before dismantling, the equipment should be thoroughly cleaned and dried out. After drying, the IR test should be repeated. Dismantling should only be considered if the reading is still low after drying.

SECTION 3 Current Transformer (CT) Testing

Q11. What is the definition of the CT knee-point voltage according to IEC?

ANSWER According to IEC 60044-1, the knee-point voltage is the point on the excitation curve where a 10 percent increase in voltage causes the magnetizing current to increase by 50 percent. It is the point where the CT core begins to saturate.

Q12. What is the purpose of the CT Knee-Point Test?

ANSWER The knee-point test is done to determine the voltage at which the CT core starts to saturate, to confirm the CT meets the required knee-point voltage for the protection scheme it feeds such as differential, REF, and distance protection, to verify that the protection CT has a higher knee-point than the metering CT to confirm correct core identification, and to ensure the CT can produce enough secondary voltage during maximum fault current without saturating.

Q13. What is CT demagnetization and when must it be done?

ANSWER CT demagnetization is the process of removing residual magnetic flux from the CT core. Residual flux can be caused by heavy fault currents with a DC component or any DC voltage applied to the CT such as during a winding resistance test. Demagnetization must be done before ratio measurements to get accurate results, after any test that used DC such as winding resistance or contact resistance tests, and after a CT has been subjected to a heavy fault current. The most common method is to apply a variable AC voltage to the secondary winding, increasing it past the saturation point, then slowly reducing it to zero.

Q14. What is the acceptance criterion for CT Winding Resistance test results?

ANSWER Measured resistance across phases should be within 2 percent to 5 percent of each other. Larger differences suggest loose connections, shorted turns, or broken strands. Measured resistance should be within 5 percent to 10 percent of the nameplate or factory test value corrected to 75 degrees Celsius. Deviations greater than 10 percent need investigation. For multi-tap CTs, resistance values should increase proportionally with the number of turns between taps.

Q15. Why must a CT never be left with its secondary circuit open when the primary is energized?

ANSWER When a CT primary carries current and the secondary circuit is open, the primary current all becomes magnetizing current. This creates a very high voltage at the open secondary terminals that is dangerous to human life and can be lethal, can damage connected equipment, and can destroy the CT itself. This is the most dangerous condition in CT testing and service.

Q16. What is the purpose of the CT Primary Injection Test and what does it verify?

ANSWER The CT Primary Injection Test injects a known current through the CT primary and verifies phase identification of R, Y, and B phases, CT core identification for protection versus metering cores, single point of earthing on the CT secondary, CT polarity confirming current direction from P1 to P2 matches secondary from S1 to S2, test plug operation and identification, integrity of secondary wiring and burden, and reading accuracy at the final connected device such as relay or meter.

SECTION 4 Voltage Transformer (VT) Testing

Q17. What test voltage is used for VT IR testing?

ANSWER Between the VT primary winding and any other terminal, the injection voltage is 5 kV DC. Between VT secondary windings and secondary-to-earth, the injection voltage is 500 V DC.

Q18. What does the VT Secondary Injection Test verify?

ANSWER The VT secondary injection test injects a known voltage into the VT secondary circuit and verifies phase identification of R, Y, and B at VT secondary, VT core identification for protection versus metering cores by switching each MCB on and off, single point of earthing and correct star point location, polarity with no reversal of voltage direction, integrity of secondary wiring and connections, and reading accuracy at the final connected device.

Q19. What is the difference between a CT ratio test and a VT ratio test in terms of the test connection?

ANSWER For a CT Ratio Test, current is injected into the primary. The secondary terminal must never be left open during current injection. All other open terminals are closed or shorted. Current always flows in a closed loop. For a VT Ratio Test, voltage is injected across the primary terminals. The secondary is not shorted because VTs are voltage devices. Shorting a VT secondary would cause high current and damage.

Q20. What are the tolerance limits for VT ratio error?

ANSWER Tolerance limits depend on the VT accuracy class. Class 0.2 allows plus or minus 0.2 percent ratio error. Class 0.5 allows plus or minus 0.5 percent ratio error. Class 3P allows plus or minus 3 percent ratio error. Results must also be compared with factory test reports. Any significant difference from previous test records must be investigated.

SECTION 5 Circuit Breaker (CB) Testing

Q21. What tests are performed on a circuit breaker during commissioning?

ANSWER The following tests are performed: Visual and Mechanical Inspection, Insulation Resistance Test at 5 kV DC, Contact Resistance Test which is a micro-ohm test at 100 A DC, Timing Test covering opening, closing, and O-C-O sequence times, and Motor Spring Charge Timing and Load Test.

Q22. What are the general acceptance values for circuit breaker contact resistance?

ANSWER For MV and HV circuit breakers the typical limit is 200 to 300 microohms per pole. For LV circuit breakers the typical limit is 100 microohms per pole. Phase balance requires that readings across all three poles should be within plus or minus 20 percent of each other. Any abnormally high resistance indicates worn or pitted contacts, corrosion, or loose connections. Always compare with the OEM nameplate or test report values.

Q23. What are typical acceptance values for circuit breaker timing test?

ANSWER Opening time is usually 30 to 60 ms and may be higher for some types. Closing time is usually 50 to 100 ms. Pole discrepancy which is the difference between poles is typically 3 ms maximum. Contact bounce should be minimal as per OEM standard. Results must comply with IEC 62271-100 or IEEE C37.09 and the manufacturer tolerances.

Q24. What does a Motor Spring Charge Timing Test check, and what is the typical acceptance value?

ANSWER This test measures Spring Charging Time which is how long the motor takes to fully charge the closing spring from empty, and Motor Load which is the current consumed by the motor during the charging process. The typical spring charging time is 5 to 15 seconds. Deviation should not exceed plus or minus 10 percent of the nameplate value. If the time is too long it indicates mechanical friction, low control voltage, or a motor problem.

SECTION 6 Power Transformer Testing

Q25. What tests are carried out on a power transformer during commissioning?

ANSWER The following tests are performed: Insulation Resistance Test, Polarization Index Test, Winding Resistance Test, Turns Ratio Test, Excitation Current Test which is the Open-Circuit Test, Percentage Impedance Test which is the Short-Circuit Test, Magnetic Balance Test, Vector Group Test, Oil Breakdown Voltage Test, Cooling Fan Motor Test, OLTC Tap Changer Operational Check, and Oil and Winding Temperature Sensor Check.

Q26. What is the Polarization Index test and what does it indicate?

ANSWER The Polarization Index is a ratio used to assess insulation health. It is calculated as PI equals IR reading at 10 minutes divided by IR reading at 1 minute. Per IEEE C57.152, a PI below 1.0 is dangerous and indicates wet or contaminated insulation. A PI from 1.0 to 2.0 is questionable and needs investigation. A PI from 2.0 to 4.0 is good. A PI above 4.0 is excellent. The minimum acceptable PI per the commissioning manual is 1.25.

IMPORTANT NOTE A PI of 1.1 fails the acceptance criterion even though it is above 1.0. Many engineers wrongly use 1.0 as the threshold instead of the correct minimum of 1.25.

Q27. Why must the transformer winding resistance be corrected to 75 degrees Celsius before comparing with factory data?

ANSWER Winding resistance changes with temperature. The resistance is higher at higher temperatures. To make a fair comparison between test results taken at different ambient temperatures and the factory test results which are referenced to 75 degrees Celsius, all measurements must be converted to the same reference temperature using standard formulas. Without this correction the comparison would be meaningless.

Q28. What does the Vector Group Test on a power transformer verify, and why is it important?

ANSWER The Vector Group Test verifies the correct phase relationship between the HV and LV windings such as Dyn11 meaning LV lags HV by 30 degrees, and the correct winding connections on each side. It is important because a wrong vector group causes incorrect operation of differential protection relays, parallel operation of transformers is only possible if they have the same vector group, and incorrect vector group causes incorrect power flow direction readings.

Q29. What does the Percentage Impedance test measure and what is the acceptance tolerance?

ANSWER The Percentage Impedance test measures the voltage required at the HV winding to circulate rated current with the LV winding short-circuited, expressed as a percentage of rated voltage. The acceptance tolerance per SEC standard is plus or minus 10 percent of the nameplate value. For example, if the nameplate says 10.5 percent, the acceptable range is from 9.45 percent to 11.55 percent. A value of 11.5 percent would be within tolerance but must be compared with the factory test certificate.

IMPORTANT NOTE The common mistake is applying plus or minus 10 percent as an absolute value instead of plus or minus 10 percent of the nameplate value. The correct interpretation is relative to the nameplate, not absolute.

Q30. You measure winding resistance at Tap 8 as 1.200 ohms and at Tap 9 as 0.950 ohms. What does a sudden 21 percent drop between adjacent taps indicate?

ANSWER A sudden large step in resistance between adjacent taps that is much larger than the expected incremental change per tap indicates a problem inside the On-Load Tap Changer. Possible causes include a high-resistance or open-circuit connection at that OLTC tap contact indicating contact deterioration, an OLTC transition resistor problem, or a winding connection issue at that specific tap. The winding resistance must change gradually and proportionally from tap to tap. Any sudden large deviation typically greater than 2 percent per step must be investigated before the transformer is energized.

IMPORTANT NOTE Accepting a large tap-to-tap resistance step as normal variation is a common error. Gradual step changes are expected across the tap range but sudden large jumps are a red flag for OLTC defects.

SECTION 7 Power Cable Testing

Q31. What tests must be performed on 11 kV and 33 kV power cables during commissioning?

ANSWER The following electrical tests are required: Sheath armor continuity test, Insulation Resistance test at 5 kV DC before and after the HV test, Phasing and continuity test of the main conductor, and High Voltage Test using the VLF Very Low Frequency method.

Q32. What is the VLF HV test for cables, and why is 0.1 Hz used instead of 50 Hz?

ANSWER The VLF test applies high voltage to the cable at a very low frequency of 0.1 Hz instead of normal 50 Hz to verify the cable insulation can withstand the required voltage. The reason 0.1 Hz is used is that power cables have a large capacitance. At 50 Hz the reactive current would be very large and require enormous test equipment. At 0.1 Hz which is 500 times lower than 50 Hz the capacitive current is very small and the same test can be done with much smaller equipment while the dielectric stress on the insulation is similar to power frequency.

Q33. Why must the cable insulation resistance test be performed both before and after the HV test?

ANSWER The IR test before the HV test confirms the cable insulation is in a suitable condition to be subjected to high voltage. A very low IR before the test suggests the cable may fail and the HV test should not proceed. The IR test after the HV test confirms the insulation was not damaged during the high voltage test. If IR is significantly lower after the HV test it indicates the HV test may have weakened or partially damaged the insulation.

Q34. During VLF testing of a cable, the leakage current rises from 2 mA to 8 mA over the one-hour test period. The cable does not flash over. Do you pass or fail the cable?

ANSWER Fail the cable. Two problems exist. The absolute value has increased significantly from the factory baseline. More critically, the rising trend during the test indicates a time-dependent dielectric breakdown mechanism which is a sign of insulation ageing, moisture ingress, or a developing defect. Stable leakage current is acceptable but a rising current indicates the insulation is progressively deteriorating under voltage stress. The cable must be isolated, the defect located using VLF tan-delta testing or TDR, and the insulation repaired or replaced before energization.

IMPORTANT NOTE Focusing only on whether flashover occurred without noticing the rising trend is the most common mistake. A cable with rising leakage current during the test is more dangerous than one with a stable reading near the limit.

Q35. During cross bonding verification, you inject 100 A and measure 8 A at one link box. The acceptance criterion is 5 percent maximum. What action do you take?

ANSWER The link box showing 8 A which is 8 percent of 100 A injected fails the test and must be investigated. High sheath circulating current in cross-bonded cables indicates a cross-bonding connection error where the bonding leads are not connected in the correct sequence. Common causes are two bonding leads swapped at the link box, wrong link box connection during installation, or a damaged SVL preventing correct cross-bonding. The failed link box must be opened, the connection diagram verified against the actual cable phase positions, and the bonding leads correctly reconnected.

IMPORTANT NOTE Accepting 8 percent because it is only 3 percent above the limit is wrong. Cross bonding failures cause continuous sheath circulating currents during normal operation leading to sheath overheating, accelerated cable ageing, and eventual insulation failure.

SECTION 8 Overcurrent and Earth Fault Relay Testing

Q36. What are the main tests performed on an Overcurrent and Earth Fault relay during commissioning?

ANSWER The main tests are measurement checks for current and voltage metering accuracy, pick-up and drop-off testing for time overcurrent 51 and 51N elements, Normal Inverse curve timing tests at different multiples of pickup current, pick-up, drop-off, and timing for instantaneous overcurrent 50, Broken Conductor 46BC pick-up drop-off and timing, Sensitive Earth Fault SEF measurement pick-up drop-off and timing, Auto-reclose function checks 79, binary input and output contact checks, fault recorder and event recorder checks, and Final Trip Test.

Q37. What is the IDMT characteristic of an overcurrent relay and why is it preferred in distribution systems?

ANSWER An IDMT relay operates faster when the fault current is larger and slower when the current is smaller. The operating time is inversely proportional to the fault current. It is preferred in distribution systems because for a large fault close to the source the relay trips quickly to limit damage. For a small overload far from the source it trips more slowly allowing time-graded coordination with downstream protection. This self-adjusting behavior means faults are cleared faster the more severe they are.

Q38. How do you perform a pick-up test for a time overcurrent 51 element?

ANSWER Calculate the expected pick-up current from the relay settings as pick-up current equals setting multiplied by nominal current. Inject current into the appropriate input of the relay. Slowly increase the current until the pick-up indication turns on and record this value. Slowly reduce the current until the pick-up indication turns off and record this drop-off value. Calculate the percentage error between measured and expected values. Compare with the manufacturer allowed tolerance which is typically plus or minus 5 percent for most numerical relays. Chattering contacts or LEDs are not considered a proper pick-up.

Q39. How do you calculate the percentage error for a relay test result?

ANSWER Percentage Error equals Actual Value minus Expected Value divided by Expected Value multiplied by 100. Example: Pick-up setting is 1.00 A and measured pick-up is 1.005 A. The error is 1.005 minus 1.000 divided by 1.000 multiplied by 100 which equals 0.5 percent. If the manufacturer allows plus or minus 7 percent and the measured error is 0.5 percent the result is acceptable.

Q40. What is the Broken Conductor protection and how is it detected by the relay?

ANSWER Broken Conductor protection detects a broken phase conductor on an overhead line feeder. When a conductor breaks the current in the broken phase drops or disappears creating a current unbalance between the three phases. This unbalance contains both positive sequence and negative sequence current components. The 46BC element measures the ratio of I2 to I1 which is negative to positive sequence current. When this ratio exceeds the pickup setting the relay detects the broken conductor condition. Testing requires keeping positive sequence current constant and increasing negative sequence current until the element picks up.

Q41. What is Sensitive Earth Fault protection and when is it used?

ANSWER SEF protection is used in systems where the earth fault current is very small due to high impedance or resistance earthing. In NEDC systems SEF uses a Core Balance Current Transformer where all three phase conductors pass through the center of a single ring-type CT. Under healthy conditions the three phase currents cancel each other out and the CBCT output is zero. When an earth fault occurs the unbalanced current creates a net current through the CBCT which operates the relay. SEF can detect very small earth fault currents that a standard earth fault relay would miss.

Q42. What is the Auto-Reclose function and when is it blocked?

ANSWER Auto-Reclose is a function that automatically recloses the circuit breaker after it has tripped due to a fault. About 80 to 85 percent of faults on overhead lines are transient such as lightning or wind-blown debris. The AR function tries to restore supply after a short dead time. The sequence is: protection trips CB, AR starts dead time, CB recloses, if fault cleared AR success, if fault still present final lockout trip. AR is blocked for three-phase faults because a permanent fault is assumed, Broken Conductor faults, Sensitive Earth Fault, and Instantaneous DT overcurrent trips. AR is initiated for single-phase and two-phase IDMT faults on overhead lines.

SECTION 9 Voltage Relay Testing (27, 59, 59NVD)

Q43. What is the difference between Undervoltage 27 and Overvoltage 59 protection?

ANSWER Undervoltage 27 protection detects voltage below the set threshold. The cause is abnormal system operation, faults, or large motor starting. The danger is that equipment operating at low voltage draws more current and may overheat. It protects motors, generators, and transformers from thermal stress. Overvoltage 59 protection detects voltage above the set threshold. The cause is loss of load, generator overspeed, or tap changer failure. The danger is that high voltage stresses insulation and causes cumulative damage over time. It protects all equipment from insulation damage due to excessive voltage.

Q44. Why must a pre-fault voltage be applied before testing the Undervoltage 27 relay timing?

ANSWER For the 27 relay the element is already picked up whenever the voltage is below the setting. If the test starts with zero voltage the element is already in the picked-up state before the timer begins. To measure the correct time delay a pre-fault voltage above the pickup setting must be applied first. Then the voltage is dropped below the pick-up setting and the timer starts. This simulates real conditions where voltage drops from normal to fault level.

Q45. What is Neutral Displacement Voltage 59NVD protection and where is it used?

ANSWER 59NVD protection detects earth faults in systems where the fault current is very small because the system neutral is isolated or resistance earthed. In an isolated neutral system when a single-phase earth fault occurs the system neutral point shifts from its normal position creating a residual zero sequence voltage that the 59NVD relay measures. Applications include protection on the delta side of transformers where there is no neutral for earth fault current to flow, and 33 kV primary substation incomer circuits. The NEDC target setting is the NVD voltage pickup equal to 10 V secondary corresponding to 2 to 6 kV primary on a 33 kV over 110 V VT.

SECTION 10 Directional Overcurrent Relay Testing (67, 67N)

Q46. Why is Directional Overcurrent 67 protection used instead of plain Overcurrent 51 on some feeders?

ANSWER Directional overcurrent is used when the power system is not radial and power can flow from both directions such as in a ring main or parallel feeder system. In parallel transformers if one transformer has a fault the other feeds current into the fault and a non-directional relay cannot tell which direction the fault current is coming from. Directional relays only operate for current flowing in one specified direction preventing unwanted trips for through-fault or reverse-fault conditions. Three conditions must all be met for the 67 relay to operate: current is above the pickup setting, the time delay has elapsed, and the fault is in the correct forward direction.

Q47. What does the Maximum Torque Angle or Relay Characteristic Angle mean for a directional relay?

ANSWER The RCA is the angle between the polarizing voltage and the relay current at which the relay produces its maximum sensitivity. The relay is most sensitive to operate when the fault current angle matches the RCA setting. For example if RCA is 45 degrees forward direction towards the transformer the relay is designed to detect current flowing towards the transformer at a typical fault angle. Current flowing in the opposite direction will not cause the relay to operate. Testing requires applying voltage and current at the set angle and confirming pickup, then rotating the current angle until pickup drops out to identify the boundary of the operating region.

Q48. What is the purpose of the Memory Voltage function in directional relays?

ANSWER The Memory Voltage function stores a memory of the pre-fault voltage for a short time typically 2 seconds when the measured voltage drops to zero. This is needed because for a three-phase close-in fault all three phase voltages drop to near zero. Without voltage the relay has no reference to determine direction and cannot operate correctly. The memory voltage gives the relay a reference voltage from just before the fault allowing it to determine direction and trip correctly even when measured voltage is zero. Testing requires applying normal pre-fault voltages and then dropping all voltages to zero while keeping the fault current injected. If the relay trips the memory voltage function is working.

SECTION 11 Transformer Differential Relay Testing (87T)

Q49. What is the basic principle of Transformer Differential Protection 87T?

ANSWER The 87T relay compares the current entering the transformer on the HV side with the current leaving on the LV side. Under normal load or external fault conditions the current entering equals the current leaving after accounting for the turns ratio and vector group. The difference current Idiff is near zero and no trip occurs. Under an internal transformer fault current enters but does not exit normally. The Idiff exceeds the pickup setting and the relay trips. The relay uses CTs on both HV and LV sides and subtracts the secondary currents to calculate the differential current.

Q50. Why does the transformer differential relay need harmonic restraint with 2nd and 5th harmonic blocking?

ANSWER When a transformer is first energized a large inrush current flows in the first-energized winding only. This current can be up to 10 times rated current, flows only in one winding looking like a differential current, and would cause the 87T relay to trip unnecessarily. The inrush waveform contains a large proportion of 2nd harmonic which is 100 Hz in a 50 Hz system. The relay measures the 2nd harmonic content. When the 2nd harmonic exceeds the blocking threshold typically 15 to 20 percent the relay blocks the differential trip knowing it is inrush. The 5th harmonic blocking prevents false trips during transformer overexcitation caused by overvoltage.

Q51. During the 87T stability test, you inject 100 A primary current and measure I1 equals 100 A at 0 degrees and I2 equals 98 A at 180 degrees. The relay does not trip. A trainee says the 2 A difference means the relay is insensitive. Who is right?

ANSWER The trainee is wrong. For a stability test I1 and I2 should be equal in magnitude and 180 degrees apart. This simulates through-fault load or external fault current where both CTs see the same current flowing in opposite directions. The small 2 A difference is normal CT accuracy variation and falls within the restrain region of the bias characteristic. The relay correctly restrains. If the relay had tripped it would indicate a stability failure which is a dangerous problem.

IMPORTANT NOTE Confusing the stability test with the sensitivity test is the most common mistake. In stability you want no trip. In sensitivity you deliberately swap one CT polarity and want the relay to trip.

Q52. You are testing the 87T transformer differential relay for a YNd11 transformer. CT star points are earthed towards the transformer on both HV and LV sides. After secondary injection, the relay shows I_diff ≠ 0 even with perfect balanced three-phase currents injected. What is the most likely cause?

ANSWER The vector group compensation has not been correctly configured in the relay. A YNd11 transformer introduces a 30 degree phase shift between HV and LV windings. The relay must be configured with the correct vector group to mathematically compensate this 30 degree shift internally. Without correct compensation the differential current will never balance to zero even with healthy through-fault current. The engineer must verify the relay vector group setting matches the transformer nameplate.

> **IMPORTANT NOTE** Engineers sometimes assume only the CT ratio needs matching. The vector group compensation inside modern numerical relays is equally critical and is easily overlooked during configuration.

Q53. What is the differential slope characteristic and why does it have two slopes?

> **ANSWER** The differential operating characteristic is a graph of differential current Idiff on the vertical axis versus restraint current Irest on the horizontal axis. The relay trips when the operating point falls above the characteristic curve. Slope 1 is a lower slope used for normal load range providing more sensitivity to faults at normal load levels. Slope 2 is a steeper slope used at high load currents where CT errors are larger, providing stability against false trips due to CT mismatch at high through-fault currents. The two-slope design gives the relay both sensitivity at low currents and stability at high currents.

SECTION 12 Restricted Earth Fault Protection (64N)

Q54. What is Restricted Earth Fault protection and what does it protect against?

ANSWER REF protection detects earth faults inside the transformer winding itself, specifically in the star winding near the neutral point. Standard transformer differential protection 87T cannot detect faults close to the neutral point because very little current flows for a fault near the neutral and the Idiff is too small to exceed the 87T pick-up setting. REF uses phase CTs on each phase of the protected winding and a Neutral CT on the transformer neutral. In healthy conditions or external faults phase currents plus neutral current equals zero and the relay restrains. For an internal earth fault the balance is broken, differential current flows through the relay, and a trip occurs. REF is highly sensitive and can detect faults involving less than 10 percent of the winding.

Q55. What is the function of the stabilizing resistor in the high-impedance REF scheme?

ANSWER In a high-impedance REF scheme the stabilizing resistor is connected in series with the relay measuring element. Its purpose is to maintain stability and prevent false trips during external faults when one CT may saturate. During an external fault if one CT saturates spill current appears in the differential circuit. This spill current would normally cause a false trip. The high impedance of the resistor plus relay prevents this spill current from reaching the relay operating level. All CTs in the scheme must have the same ratio and similar knee-point voltage, and the knee-point voltage must be significantly higher than the voltage developed across the relay during maximum external fault.

Q56. Why must the Neutral Earthing Resistor be bypassed during the REF stability test?

ANSWER The NER limits the fault current in the neutral of the transformer to a low value typically 300 to 600 A. During a stability test current is injected through the CT primary loop. If the NER remains in circuit it severely limits the current flow making it impossible to achieve the necessary secondary injection levels to confirm stability. By bypassing the NER by short-circuiting it, current can flow freely through the neutral path allowing sufficient current injection to properly test REF stability. The REF trip link must also be isolated during this test to prevent accidental tripping.

IMPORTANT NOTE Engineers sometimes try to increase injected current to overcome the NER without removing it. This can overload the injection kit and still not achieve proper stability test conditions.

SECTION 13   Busbar Differential Protection (87B)

Q57.   What is the CT supervision relay in a busbar protection scheme and how does it work?

ANSWER   The CT supervision relay monitors the CT secondary circuit for any open circuit or abnormal condition. In a high-impedance busbar scheme if a CT secondary circuit breaks open it appears like a fault and causes a spill current to flow through the protection relay potentially causing a false trip. The CT supervision relay is a sensitive relay connected across the bus wire of each protection zone. Under normal healthy conditions it does not operate. When a spill current is detected that exceeds its pickup caused by an open CT secondary it operates with a time delay of typically 3 seconds. When it operates it short-circuits the CT wire of the affected zone to prevent the busbar relay from operating during a genuine through-fault.

Q58.   What are the checks required for Busbar Protection 87B before starting commissioning?

ANSWER   The final settings for the busbar protection relay must be applied and tested. All CT secondary injection tests for busbar CTs must be completed. The stabilizing resistors series and shunt must be correctly set and verified against the approved settings. The CT supervision contacts must be isolated before starting sensitivity tests. All CT star points must be earthed only at the protection panel and towards the busbar. The Metrosil characteristics must be verified by plotting the voltage versus current curve and comparing with approved data. The main zone and check zone protection must both be fully tested before stability tests begin. Only both zones operating together should produce a busbar trip.

Q59.   During busbar protection stability test, your phase angle meter shows zero degrees between two feeder CTs. Should the busbar relay trip?

ANSWER   No. Zero degrees between two feeder CTs during a stability test means both CT secondary currents are in phase which means the current is flowing into one feeder and out of another feeder simulating a through-fault external to the busbar zone. With star points towards the busbar all feeder CTs see current flowing away from the busbar. The net differential current is zero and the busbar relay should restrain. If the relay trips on this condition it fails the stability test which is a critical defect.

IMPORTANT NOTE Misinterpreting the phase angle result is the most common mistake. Zero degrees between CTs during stability test is correct for through-fault current and the relay must not trip. For the sensitivity test one CT polarity is swapped to get 180 degrees simulating a busbar fault and then the relay must trip.

Q60. What is the difference between Main Zone and Check Zone in High Impedance Busbar Protection?

ANSWER The Main Zone or Discrimination Zone is the primary protective zone that encompasses the complete busbar. One protection zone covers each busbar section. If a fault is detected in this zone only the feeders connected to that busbar section are tripped. The Check Zone is an additional supervisory zone that covers the entire busbar system and all sections together. Its purpose is to prevent false trips due to CT wiring errors, CT supervision maloperation, or other spurious signals. Both Main Zone and Check Zone must operate together to issue a busbar trip. This two-out-of-two logic provides extra security against incorrect tripping.

SECTION 14 Distance Protection Relay (21)

Q61. What is the secondary impedance setting for a distance relay and how do you convert primary impedance to secondary?

ANSWER Distance relays measure secondary impedances because they receive signals from CTs and VTs. The secondary impedance is calculated as Z secondary equals CT Ratio divided by VT Ratio multiplied by Z primary. For example if the rated system primary voltage is 33 kV, CT ratio is 400/1, and VT ratio is 33,000/110 which equals 300, then Z secondary equals 400 divided by 300 multiplied by Z primary which equals 1.333 multiplied by Z primary. All zone reach settings must be entered as secondary impedance values.

Q62. Zone 1 of a distance relay is set to reach 80 percent of line impedance. You inject exactly Z equals 0.8Zb and the relay trips. Is this correct and what happens if you inject Z equals 0.79Zb?

ANSWER At Z equals 0.8Zb the relay is exactly at the Zone 1 boundary and it should trip instantaneously. This is correct. At Z equals 0.79Zb the impedance falls inside Zone 1 closer to the relay so the relay will still trip instantaneously. The boundary is the maximum reach and any impedance below the boundary which is nearer to the relay is within the protection zone. The relay trips for all impedances from zero up to its reach setting.

IMPORTANT NOTE Engineers sometimes inject Z below Zone 1 expecting the relay not to trip because it is not at the boundary. The relay trips for all impedances from zero up to its reach setting.

Q63. What is the Switch Onto Fault function in distance protection and how is it tested?

ANSWER SOTF is a function that provides instantaneous fault clearance when a circuit breaker is manually closed onto a pre-existing fault. Without SOTF a Zone 2 or Zone 3 fault would be cleared with the usual time delay. The SOTF function links to the circuit breaker closing event and activates instantaneous tripping through Zone 2 for a short window after closing typically 500 milliseconds. Testing procedure: Create three states in the test set state sequencer. First state is normal voltage with no current. Second state is CB closure with minimum load current within the action time window. Third state introduces a Zone 2 fault while still within the action time. SOTF must operate instantaneously. Then test again with the fault applied after the action time has expired. Zone 2 time delay must then apply normally.

Q64. During PUTT testing, SS1 sends a permissive signal but SS2 does not trip instantly and waits for Zone 2 time. What went wrong?

ANSWER The permissive signal from SS1 was not received at SS2. In PUTT, SS2 should trip instantaneously when it both detects the fault in its Zone 2 and receives a permissive signal from SS1. If the communication channel has failed or the binary input for the received signal is not correctly mapped in the relay configuration, SS2 will only trip after Zone 2 time delay. The engineer must verify the teleprotection link is operational, the received signal binary input is correctly wired and configured, and the send and receive logic is tested end-to-end.

IMPORTANT NOTE Assuming Zone 2 time delay automatically means the relay is faulty is the common mistake. The first check should always be the communication channel integrity and binary input wiring not the relay zone settings.

Q65. What are the three VT failure conditions and how is each tested?

ANSWER The first condition is unbalanced VT failure which occurs when one or two phase voltages are lost. Detection criterion is the ratio of negative-sequence voltage to positive-sequence voltage exceeding the threshold. The second condition is three-phase VT failure which occurs when all three phase voltages simultaneously drop below the threshold combined with a voltage jump. The relay checks for a voltage jump to distinguish from a genuine three-phase fault. The third condition is switching onto a three-phase VT failure where CB closes and all voltages are already at zero level with no voltage jump but voltages below threshold with CB closed. Testing requires injecting three-phase voltage and current and then removing phases one by one to verify each condition activates and blocks all zones.

SECTION 15 AVR and APFC Testing

Q66. What is the voltage tolerance bandwidth in an AVR relay and how is the secondary setting calculated?

ANSWER The voltage tolerance bandwidth is the dead-band around the voltage setpoint within which the AVR does not issue any tap change command. Calculation example: if the AVR setpoint is 11.3 kV on a 33 over 11 kV transformer with VT ratio of 11,000/110 volts and bandwidth setting of 1.8 percent, then the equivalent secondary setpoint is 110 divided by 11,000 multiplied by 11,300 which equals 113 volts phase to phase, and phase to neutral is 113 divided by root 3 which equals 65.24 volts. Bandwidth equals 65.24 multiplied by 0.018 which equals 1.174 volts. The upper limit is 66.414 volts and the lower limit is 64.066 volts.

Q67. What is the difference between Master Follower and Minimizing Circulating Current mode in parallel transformer AVR operation?

ANSWER In Master Follower mode one transformer AVR is designated as master and controls the tap changer based on measured voltage. All other AVRs simply follow the master and adjust their tap changers to match the master tap position. This works well when all transformers have identical ratings and tap step voltages. In Minimizing Circulating Current mode the AVR continuously monitors the circulating current between paralleled transformers and adjusts each transformer tap changer independently to reduce the circulating current to zero. This is used when transformers have different ratings or slightly different impedances.

Q68. What is the discharge timer in an APFC relay and why is it important?

ANSWER The discharge timer is a blocking time that activates after a capacitor stage is switched off. During this time the stage cannot be switched back on. When a capacitor bank is disconnected the capacitors still hold a residual charge. If the stage were reconnected before the capacitors fully discharged the closing transient current would be very large damaging the contactors and capacitor cells. The discharge timer ensures enough time passes for the capacitors to discharge completely before reconnection is allowed. In NEDC practice the discharge time is typically 600 seconds.

SECTION 16 Under Frequency Relay (81) and Synchrocheck (25)

Q69. How do you test multiple stages of under frequency relay protection and what precaution is needed between stages?

ANSWER Apply rated three-phase voltage at nominal frequency. For Stage 1 testing reduce frequency slowly below the Stage 1 pickup setting and verify the Stage 1 pickup LED activates. For Stage 2 testing before testing Stage 2 disable Stage 1 by setting it to off or using a test override. If Stage 1 is not disabled it will pick up and trip before Stage 2 can be tested and the exact Stage 2 pickup cannot be measured accurately. After each stage is tested normalize that stage to its setting before testing the next stage.

Q70. What conditions must be satisfied for a Synchronism Check 25 relay to permit closing of a circuit breaker?

ANSWER Three conditions must all be within the allowed limits simultaneously. First the Voltage Difference which is the magnitude difference between the two voltages must be within the set limit. Second the Frequency Difference between line and bus must be within the set limit. Third the Phase Angle Difference between line and bus must be within the set limit. If any one of these three conditions is outside the allowed window the relay will not give a permission signal and the circuit breaker cannot close.

Q71. During Synchronism Check relay testing you inject U1 equals 100 V at 0 degrees and U2 equals 100 V at 25 degrees. The relay angle setting is 20 degrees. Does the relay permit closing?

ANSWER No. The angle difference between U1 and U2 is 25 degrees which exceeds the relay closing angle setting of 20 degrees. The relay will block the close command. For the relay to permit closing the phase angle difference must be within the set window. The test must verify the relay permits closing when angle difference is below the setting and blocks when above it. Both boundary conditions must be tested.

IMPORTANT NOTE Testing only the permit condition and not the block condition is a common mistake. Engineers frequently forget to test the boundary condition where the relay should block closing.

Q72. What is Dead Bus Live Line mode in the synchrocheck relay and when is it used?

ANSWER Dead Bus Live Line mode allows the circuit breaker to close even when one side has no voltage. Most Synchronism Check relays have two additional modes besides Live-Live synchrocheck. Dead Bus Live Line allows closing to energize a dead bus from a live line. Live Bus Dead Line allows closing to pick up a dead line from a live bus. Dead Bus Dead Line allows closing when both sides are dead. These modes must be specifically enabled in the relay settings. Their purpose is to allow practical system restoration without waiting for synchronism conditions that cannot be achieved when one side is dead.

SECTION 17 ATS, Cross-Tripping, and Load Shedding Schemes

Q73. What is a Cross-Tripping Scheme and what must be checked during commissioning?

ANSWER A Cross-Tripping Scheme is a protection scheme where a fault detected by a relay on one piece of equipment also trips a circuit breaker on another piece of equipment. For example a fault on the 11 kV LV side of a transformer may cause both the 11 kV breaker and the 33 kV HV breaker to trip even though the 33 kV relay did not detect the fault directly. During commissioning the following must be checked: all initiating elements and blocking conditions are correctly wired and functional, all binary inputs and outputs operate as per the scheme, all interlocks and blocking conditions work correctly, the final trip matrix is verified showing which relay trips which breaker, DC supply integrity and TCS are healthy, and wiring path and polarity are correct.

Q74. During ATS commissioning, you manually open the main incomer and Q2 closes after 3 seconds as expected. You then restore the main incomer but Q2 does not open after 15 seconds. What is the most likely fault?

ANSWER The ATS return-to-normal timer is not functioning correctly or is not configured. When the main incomer is restored the ATS logic should detect that the incomer is healthy again and initiate a 15-second time delay before transferring back to avoid chattering on momentary supply disturbances. Possible causes are that the 15-second timer setting is wrong or not programmed, the main incomer auxiliary contact status feedback is not properly wired to the ATS controller, or the ATS is configured for manual return mode requiring operator intervention to restore normal supply.

IMPORTANT NOTE Immediately assuming Q2 is mechanically stuck or its trip coil has failed is the common mistake. Logic and timer configuration and feedback contact problems are far more common causes of ATS malfunction during commissioning.

Q75. Why must Q2 remain open when Q1 trips due to a protection relay operation, even though Q2 closed automatically when the main incomer was manually opened?

ANSWER This is a critical safety interlock. When Q1 trips due to a protection relay operation caused by a fault on the busbar or load, Q2 must not transfer automatically. The logic distinguishes between supply failure on incomer 1 where Q2 can transfer because the fault is upstream and load is healthy, versus a load fault causing Q1 to trip by protection where transferring would energize the faulted load from the alternate supply causing further damage or injury. Q2 remaining open on protection-initiated Q1 trip is a fundamental ATS safety interlock.

IMPORTANT NOTE Not understanding why Q2 must stay open on a protection trip is a common gap. Engineers sometimes report this as ATS malfunction when it is actually correct and safe behavior. Failing to verify this interlock creates a serious safety risk.

SECTION 18 DC System and Battery Testing

Q76. What is the purpose of Trip Circuit Supervision and how is it tested?

ANSWER Trip Circuit Supervision monitors the health of the circuit breaker trip circuit continuously during service. It detects problems like broken wires in the trip circuit, open-circuited trip coil, blown fuse in the trip supply, and incorrect relay contacts. The TCS relay passes a small monitoring current continuously through the trip circuit. If the circuit is healthy the TCS indicates healthy. If the circuit is broken TCS issues an alarm. Testing requires removing the connection to any contact point in the trip circuit. The TCS relay should immediately drop off and issue an alarm. Reconnect and the alarm should clear. Without TCS a broken trip circuit would only be discovered during a real fault when the circuit breaker fails to trip.

Q77. A battery charger shows output ripple voltage of 350 mVac on the DC terminals during the float mode test with battery disconnected. The manufacturer specification states maximum 100 mVac. The charger engineer says this is normal because the battery was disconnected. Is this correct?

ANSWER No. This is a charger defect. The ripple voltage test is specifically performed with the battery disconnected to evaluate the charger own filter performance because the battery normally masks ripple by acting as a large capacitor. A ripple of 350 mVac against a 100 mVac limit means the charger DC filter is inadequate, failed, or incorrectly installed. High DC ripple causes overheating of relay coils, maloperation of electronic relays and IEDs sensitive to DC supply quality, and interference with SCADA systems. The charger must be repaired and the filter stage investigated before acceptance.

IMPORTANT NOTE Accepting high ripple voltage when the battery is disconnected is a common mistake. Some engineers assume the battery will always be present to smooth the ripple but battery failures, maintenance disconnections, and boost mode operation all expose sensitive equipment to unfiltered ripple.

Q78. During the battery discharge test at hour 8, one cell drops to 1.75 V. The nominal is 2 V per cell. The total bank voltage is still above the minimum. Do you accept the battery bank?

ANSWER No. The battery bank should be rejected. Individual cell end-of-discharge voltage typically must not fall below 1.8 V per cell. A single cell at 1.75 V at hour 8 indicates that cell is significantly weaker than the rest and is heading toward reverse polarity if discharge continues.

Even though the total bank voltage may still be acceptable because other cells are performing better, a weak cell creates risk of cell polarity reversal at deeper discharge which permanently damages the cell, progressive acceleration of adjacent cell degradation, and inability to sustain the load for the full required autonomy period. The weak cell must be replaced and the full 10-hour discharge test repeated.

IMPORTANT NOTE Looking only at total bank terminal voltage and ignoring individual cell monitoring is the most common error. Total voltage can mask individual cell failures which is precisely why individual cell voltage recording throughout the discharge test is mandatory.

SECTION 19 SAS and IEC 61850 Testing

Q79. During SAS testing the engineer enables an unused Ethernet port on an IED for a temporary laptop connection. Why is this a serious risk that must be reversed immediately?

ANSWER Leaving an unused Ethernet port enabled on any IED or switch is a critical cybersecurity vulnerability. The manual explicitly states additional Ethernet ports that are unused should be disabled. An enabled but unconnected port can be exploited by anyone who physically plugs into it gaining access to the IED configuration, protection settings, or the entire SAS network. During commissioning an enabled port can also introduce network loops if accidentally connected which can saturate the Ethernet ring and collapse all SAS communication. After the temporary connection is removed the port must be disabled in the switch or IED configuration and the configuration re-uploaded, verified, and saved.

IMPORTANT NOTE Treating unused port management as a minor housekeeping task is a common mistake. In IEC 61850 substations open Ethernet ports are direct entry points into the protection and control network and disabling them is a commissioning acceptance requirement not optional.

Q80. You unplug LAN-A from Server A and it correctly switches over to Server B. You consider the redundancy test passed. A senior engineer says the test is incomplete. What is missing?

ANSWER The test is incomplete because redundancy must be verified for all redundancy paths not just one. The full redundancy test matrix requires: unplugging LAN-A from Server A and verifying Server B takes over, unplugging LAN-B from Server A and verifying Server B takes over, forcing Server A off entirely and verifying Server B takes over, repeating all steps for Server B, disconnecting both network connections from the Engineering Workstation, switching off Gateway A and verifying Gateway B takes over, switching off Gateway B and verifying Gateway A takes over, and verifying each Protection IED and BCU has dual connections to two separate Ethernet switches. A single-path test only confirms one redundancy scenario.

IMPORTANT NOTE Confirming one switchover scenario and declaring redundancy proven is the most common mistake. True redundancy testing requires every single component failover to be individually verified.

Q81. GPS time synchronization is confirmed working. The GPS antenna is then removed to test the internal clock holdover mode. After 30 minutes IED event timestamps show 3-second drift relative to the gateway. Is this acceptable?

ANSWER No. IEC 61850 and protection event recording require timestamp accuracy of typically plus or minus 1 ms for sequence of events and plus or minus 4 ms for IEC 61850 GOOSE messages. A 3-second drift in 30 minutes is catastrophic for fault analysis. It would make it impossible to correctly sequence events across substations during a fault investigation. The GPS internal oscillator has a maximum allowable drift rate specified in the GPS technical manual typically less than 100 ms over 24 hours of holdover. 3 seconds in 30 minutes vastly exceeds this tolerance. The GPS unit must be replaced or recalibrated before energization.

IMPORTANT NOTE Accepting any drift as expected because the antenna is disconnected is wrong. GPS holdover performance is a specification item. Excessive drift means the GPS cannot be relied upon during satellite outages compromising the integrity of all protection event records.

Q82. A fiber optic cable run has 4 coupling points, 2 splices, and a measured length of 0.15 km at 1300 nm wavelength. The measured loss is 1.8 dB. Is this cable acceptable?

ANSWER Calculate the expected total budget loss using the manual formula for 1300 nm which is 1.5 multiplied by L plus 0.5 multiplied by C plus 0.3 multiplied by S. This gives 1.5 multiplied by 0.15 plus 0.5 multiplied by 4 plus 0.3 multiplied by 2 which equals 0.225 plus 2.0 plus 0.6 which equals 2.825 dB. The measured loss of 1.8 dB is less than the calculated budget of 2.825 dB. Therefore the cable is acceptable. The acceptance criterion is that measured loss must not exceed the calculated budget loss. A lower measured loss means the cable, connectors, and splices are performing better than the worst-case budget.

IMPORTANT NOTE Treating the budget loss formula result as a target value to match rather than an upper limit not to exceed is the common mistake. The budget is the maximum allowed loss and any measured value below it passes. Engineers also frequently use the wrong formula coefficients for 850 nm versus 1300 nm.

Q83. During closed loop SAS measurement testing the reactive power Q reading at SCADA is consistently positive while the HMI shows Q as negative even though the BCU shows the correct sign. The active power P sign matches everywhere. What is the most likely cause?

ANSWER This is a reactive power sign convention mismatch between the IEC 61850 station bus at the HMI and BCU level and the legacy SCADA gateway protocol such as IEC 101 or 104. Different systems use different Q sign conventions. The IEC convention uses Q positive equals inductive lagging while some SCADA systems use Q positive equals capacitive leading. The gateway protocol mapping has the Q polarity inverted in the gateway configuration or the data object MMXU.VAr is mapped with a sign-inversion scale factor at the SCADA end. The resolution requires confirming the correct Q sign convention with the SCADA engineer per the approved data mapping document and applying the sign inversion at the gateway or SCADA layer.

IMPORTANT NOTE Trying to resolve the sign mismatch at the IED or BCU level is the common mistake. The BCU is correct and the problem is in the gateway protocol mapping or SCADA configuration. Reconfiguring the IED to invert Q would corrupt the station-level measurements.

SECTION 20 Panel Scheme Checking and Energization

Q84. What is DC segregation in a protection panel and why is it important?

ANSWER DC segregation means that the different DC circuits in a protection panel are kept electrically separate from each other using separate MCBs, fuses, and wiring. The main categories that must be segregated are the trip circuit carrying the trip command to the circuit breaker trip coil, the closing circuit carrying the close command, and the alarm circuit feeding indication and annunciation circuits. The reason is that a fault in one circuit cannot affect the others. If trip and close circuits shared the same MCB a fault in the closing circuit blowing the MCB would also disable the trip circuit leaving the circuit breaker unable to clear a fault.

Q85. What is Trip Circuit Supervision and what are the three conditions it monitors?

ANSWER Trip Circuit Supervision is a continuous monitoring function that checks the health of the circuit breaker trip circuit while the circuit breaker is in service. The three conditions monitored are: first the pre-close condition where the circuit breaker is open and the trip circuit is monitored through the circuit breaker auxiliary b-contact and the trip coil, second the post-close condition where the circuit breaker is closed and monitored through the 52a contact and the trip coil, and third the latched-trip condition where after tripping monitoring continues through the 52b contact to ensure the trip circuit remains intact for any required re-trip.

Q86. What is the anti-pump circuit and how is it tested?

ANSWER The anti-pump circuit prevents the circuit breaker from continuously cycling between open and closed positions when a permanent fault is present and a sustained close command is being applied. The anti-pump circuit latches the closing relay coil open once the CB has closed. Even if the close command contact remains closed the anti-pump relay keeps the closing circuit open until the close command is fully removed and reapplied. Testing requires applying a close command and confirming CB closes, keeping the close command continuously applied, simulating a protection trip to open the CB, verifying the CB does not attempt to close again while the close command is still held, then removing and reapplying the close command to confirm the CB closes normally.

Q87. What checks must be done before a substation is energized for the first time?

ANSWER The following must be confirmed. CT and VT circuits must all be connected, shorted, single-point earthed, and star points correct. All VT circuits must be connected and isolated correctly. Power Transformer must have no temporary grounds or shorting between winding phases, all covers sealed, no oil leakage, NER earthing correct, OLTC on normal tap, and capacitor bank locked. Power Cables must have all terminations correct and cable sheaths connected to link boxes. Trip Circuits must have all trip links connected per approved settings. Auxiliaries must have no temporary connections on auxiliary transformer or RMU. Alarms must show no active alarms on annunciators, relays, or SAS HMI.

Q88. Why must phasing be proven before two sources are paralleled for the first time?

ANSWER If two sources are connected together out of phase or with wrong phase rotation a very large short-circuit current will flow instantly damaging transformers, cables, and switchgear. Phasing is proven by energizing the new incoming line from one source only and measuring the voltages and phase angles on the VT secondary. Then energizing from the other source only and comparing the two sets of measurements. If phasing is correct both sets of voltage measurements should be essentially identical. Only after phasing is confirmed may the two sources be paralleled.

SECTION 21 GENERATION AND POWER FLOW THE FUNDAMENTALS APPLIED TO REAL PROBLEMS

Q89. A single-phase line has R = 0.15 ohm and X = 0.02 ohm per conductor. It carries 4000 kW at 11 kV, 0.8 pf lagging. An engineer calculates voltage regulation as (I x Z) / VR x 100 and gets 2.4%. Is he correct?

ANSWER No. He used the wrong formula. The correct approximate formula for voltage regulation is (I x (R cos phi + X sin phi)) / VR x 100. With cos phi = 0.8, sin phi = 0.6, total R = 0.30 ohm, total X = 0.04 ohm. Load current I = 4,000,000 / (11000 x 0.8) = 454.5 A. Voltage drop = 454.5 x (0.30 x 0.8 + 0.04 x 0.6) = 454.5 x 0.264 = 120 V. Percentage VR = 120 / 11000 x 100 = 1.09%. Using IZ overestimates because Z = root(0.09 + 0.0016) = 0.308 ohm. That gives 454.5 x 0.308 = 140 V or 1.27%, still not 2.4%. The 2.4% error comes from using phase voltage as 11000 V in a single-phase system where VR is the full line voltage, which is correct here. The engineer likely used both conductors' R and X values separately without doubling them, then doubled once more incorrectly.

WHY ENGINEERS GET THIS WRONG Using IZ directly instead of I(R cos phi + X sin phi) always overestimates regulation at lagging power factor. The cosine-sine breakdown correctly projects the drop onto the voltage axis.

Q90. A 3-phase 50 Hz line is 20 km long with R = 0.7 ohm/km and L = 0.9 mH/km per phase. It supplies 1.5 MW at 12 kV, 0.81 pf lagging. You calculate XL = 5.655 ohm and VS = 8235 V phase. A trainee says VR = 12 kV so regulation = (8235 - 12000) / 12000 which gives a negative value. What went wrong?

ANSWER The trainee mixed phase and line voltages. VR (phase) = 12000 / root(3) = 6928 V. VS (phase) = 6928 + voltage drop = 6928 + 1307 = 8235 V. Percentage regulation = (8235 - 6928) / 6928 x 100 = 18.9%. The trainee subtracted the sending end phase voltage from the line voltage, which is meaningless. Regulation is always (VS_phase - VR_phase) / VR_phase x 100. Both VS and VR must be in the same unit: either both phase or both line. Never mix them.

WHY ENGINEERS GET THIS WRONG This mistake of mixing phase and line voltage in the regulation formula is extremely common. Always convert to phase voltage first since line equations are written in phase quantities.

Q91. On the same 20 km, 3-phase line above, the calculated line losses are 334 kW and efficiency is 81.8%. A colleague says the efficiency is too low and suspects a calculation error because 334 kW losses on 1.5 MW seems very high. Is the calculation correct?

ANSWER The calculation is correct. Line losses = 3 x I^2 x R. I = 1,500,000 / (1.732 x 12000 x 0.81) = 89.2 A. R per phase = 0.7 x 20 = 14 ohm. Losses per phase = 89.2^2 x 14 = 7956 x 14 = 111,400 W. Total = 334 kW. This is 22.3% of the power delivered, which is extremely high. The reason is the line resistance of 14 ohm per phase at 12 kV is very high relative to the load impedance. For comparison, the load impedance per phase = VR^2 / (P/3) = 6928^2 / 500,000 = 96 ohm. The line resistance is 14.6% of the load impedance, so 14.6% loss fraction is expected. In real networks a line this resistive at 12 kV would be replaced or the voltage stepped up to reduce current and losses. The efficiency of 81.8% correctly reflects a poorly designed or overloaded line.

WHY ENGINEERS GET THIS WRONG Engineers instinctively feel efficiency should be above 95% for any transmission line. But at distribution voltages with long lines and heavy loads, efficiency can legitimately fall well below 90%. Always check if the line resistance is a reasonable fraction of load impedance.

Q92. For a short transmission line, VS = VR + IR(R cos phi + X sin phi). A 33 kV line has R = 2 ohm and X = 8 ohm per phase. It carries load at 0.7 pf lagging. An engineer says that if he improves the power factor to unity, the voltage regulation improves. Is this always true and is there a power factor at which regulation becomes zero?

ANSWER Yes improving power factor from 0.7 lagging generally improves (reduces) regulation. At unity power factor, regulation = I x R / VR x 100, which is positive but small. At leading power factor, the X sin phi term becomes negative (since sin phi is negative for leading). At some specific leading power factor the drop IR cos phi and the rise IX sin phi exactly cancel, giving zero regulation. Setting zero = IR cos phi + IX sin phi gives tan phi = -R/X = -2/8 = -0.25, so phi = -14.04 degrees leading, meaning pf = cos 14.04 = 0.97 leading. At pf 0.97 leading the sending end and receiving end voltages are equal. Beyond this leading angle the receiving end voltage exceeds the sending end voltage (Ferranti-like behavior even under load).

WHY ENGINEERS GET THIS WRONG Engineers know lagging pf gives high regulation and unity gives lower regulation. Very few know there is a specific leading power factor where regulation is exactly zero and that beyond it the line behaves like a capacitive system with rising end voltage.

Q92. A 3-phase transformer supplies 1500 kVA at 0.7 pf lagging. The active power is 1050 kW and reactive power is 1500 x sin(45.57 deg) = 1071 kVAR. An engineer installs capacitors rated 500 kVAR. He claims the new pf = 1050 / root(1050^2 + (1071 - 500)^2). Calculate the new pf and confirm if his formula is correct.

ANSWER His formula is correct. New Q = 1071 - 500 = 571 kVAR. New S = root(1050^2 + 571^2) = root(1102500 + 326041) = root(1428541) = 1195.2 kVA. New pf = 1050 / 1195.2 = 0.879 lagging. To verify: original pf check: sin phi = Q/S = 1071/1500 = 0.714, phi = 45.57 deg, cos phi = 0.7 confirmed. New phi = arctan(571/1050) = arctan(0.544) = 28.54 deg. New pf = cos(28.54) = 0.879. The capacitors improved pf from 0.7 to 0.879. To reach unity pf, the required capacitor rating would equal the full reactive power of 1071 kVAR, not just 500 kVAR.

WHY ENGINEERS GET THIS WRONG Engineers sometimes think adding any capacitor will reach unity pf. The required capacitor rating equals the full reactive component of the load. Partial compensation only shifts the pf partway.

Q93. A 500 kVA transformer is loaded at 80% of its rating at 0.7 pf lagging. Copper loss at full load is 5 kW and iron loss is 2 kW. What is the efficiency and why does efficiency change if pf changes to 0.9 while keeping the same load kVA?

ANSWER At 80% load, load kVA = 0.8 x 500 = 400 kVA. Active power output = 400 x 0.7 = 280 kW. Copper loss at 80% load = (0.8)^2 x 5 = 0.64 x 5 = 3.2 kW. Iron loss = 2 kW (constant regardless of load). Total losses = 5.2 kW. Efficiency = 280 / (280 + 5.2) x 100 = 280 / 285.2 x 100 = 98.17%. At pf 0.9, same 400 kVA: active power output = 400 x 0.9 = 360 kW. Losses remain the same 5.2 kW since copper loss depends on current (kVA), not pf. Efficiency = 360 / (360 + 5.2) x 100 = 360 / 365.2 x 100 = 98.58%. Efficiency improves with better pf because more useful power is extracted for the same current and losses.

WHY ENGINEERS GET THIS WRONG A critical point: copper losses depend on current (kVA), not on power factor. Iron losses depend only on voltage, also not on pf. So transformer losses are fixed for a given kVA loading regardless of pf. Improved pf means more output kW for the same losses, hence better efficiency.

Q94. Two transformers A (100 kVA, Z = 4%) and B (200 kVA, Z = 5%) are connected in parallel to share a total load of 240 kVA. How much does each carry?

ANSWER For parallel transformers with different ratings and impedances, the load shares inversely as per-unit impedances referred to a common base. Using 200 kVA as base: ZA (on 200 kVA base) = 4% x (200/100) = 8%. ZB (on 200 kVA base) = 5% x (200/200) = 5%. Load on A = Total x ZB / (ZA + ZB) = 240 x 5 / (8 + 5) = 240 x 5/13 = 92.3 kVA. Load on B = 240 x ZA / (ZA + ZB) = 240 x 8/13 = 147.7 kVA. Check: 92.3 + 147.7 = 240 kVA confirmed. Transformer A (100 kVA) carries 92.3 kVA which is 92.3% of its rating. Transformer B (200 kVA) carries 147.7 kVA which is 73.9% of its rating. Transformer A is close to overload despite being the smaller one, because its lower percentage impedance causes it to pick up a disproportionately large share.

WHY ENGINEERS GET THIS WRONG Engineers assume the bigger transformer always carries more load. The actual share depends on per-unit impedance. A small transformer with low percentage Z can be overloaded while the large one runs light.

Q95. A transformer rated 33/11 kV, 20 MVA, vector group Dyn11 is protected by a differential relay. HV CT ratio is 400/1 and LV CT ratio is 1200/1. An engineer checks the relay and finds Idiff = 0.15 pu continuously with no load. He says the CTs need replacing. Is he correct?

ANSWER Probably not. Before condemning CTs, check the vector group compensation. A Dyn11 transformer has a 30 degree phase shift between HV and LV. If the relay vector group setting is wrong or not configured, the differential current will never balance to zero even with perfect CTs. Also verify the CT ratio matching. Full load HV current = 20,000,000 / (1.732 x 33,000) = 350 A. Secondary = 350/400 = 0.875 A. Full load LV current = 20,000,000 / (1.732 x 11,000) = 1050 A. Secondary = 1050/1200 = 0.875 A. Both secondaries match correctly. So the 0.15 pu standing Idiff is almost certainly due to a wrong vector group setting in the relay, not faulty CTs. Correct the Dyn11 setting in the relay configuration first, then reverify.

WHY ENGINEERS GET THIS WRONG CTs are the first thing engineers blame when 87T shows standing spill current. In most cases the root cause is wrong vector group compensation in the relay settings, which is a software configuration issue, not a hardware fault.

Q96. A 33 kV busbar has a 3-phase fault level of 500 MVA. An engineer needs to check if a circuit breaker rated 25 kA can interrupt this fault. Calculate the fault current and give a pass or fail verdict.

ANSWER 3-phase fault current = Fault MVA / (root(3) x kV) = 500 x 10^6 / (1.732 x 33,000) = 500,000,000 / 57,156 = 8748 A = 8.75 kA. The circuit breaker is rated 25 kA. Since 8.75 kA is well below 25 kA the breaker passes comfortably. The 25 kA rated CB has a safety margin of nearly 3 times the actual fault current. Note: The CB must also be rated for the system voltage. A CB rated 25 kA at 36 kV (which is the standard voltage rating for 33 kV systems) has sufficient voltage rating.

WHY ENGINEERS GET THIS WRONG Engineers sometimes confuse fault level in MVA with fault current in kA and apply the wrong acceptance criterion. Always convert MVA fault level to kA before comparing with CB rated breaking current.

Q97. A 11 kV system has a 3-phase fault level of 250 MVA. A single-phase to earth fault occurs. The zero sequence impedance is twice the positive sequence impedance. Which fault gives a higher fault current and by how much?

ANSWER Positive sequence impedance Z1 = kV^2 / MVA = 11^2 / 250 = 121/250 = 0.484 ohm. Zero sequence impedance Z0 = 2 x Z1 = 0.968 ohm. For 3-phase fault: I_3ph = V_phase / Z1 = (11000/1.732) / 0.484 = 6351 / 0.484 = 13,122 A. For single-phase earth fault: I_1ph = 3 x V_phase / (Z1 + Z2 + Z0). For a solidly earthed system Z2 = Z1 = 0.484 ohm. I_1ph = 3 x 6351 / (0.484 + 0.484 + 0.968) = 19053 / 1.936 = 9841 A. The 3-phase fault gives a higher current of 13,122 A compared to the single-phase fault of 9,841 A. The 3-phase fault current is 33% higher. When Z0 = Z1 the two are equal. When Z0 is greater than Z1 (as here) the 3-phase fault is always higher than the single-phase fault.

WHY ENGINEERS GET THIS WRONG The common assumption is that 3-phase faults are always the worst case. This is true when Z0 is greater than Z1. If Z0 is less than Z1, single-phase fault current exceeds 3-phase fault current and must be used as the dimensioning case for earth fault protection.

Q98. A 132 kV overhead line has a sag of 5 meters when the temperature is 25 degrees C and the conductor tension is 20 kN. The conductor weight is 1.5 kg/m. Using S = wl^2 / 8T, calculate the span length. Then a field engineer says the sag increases to 7 meters in summer at 50 degrees C. Is this expected and what causes it?

ANSWER From S = wl^2 / 8T: span l = root(8TS / w) = root(8 x 20000 x 5 / (1.5 x 9.81)). Weight per meter w = 1.5 x 9.81 = 14.715 N/m. l = root(800000 / 14.715) = root(54367) = 233 m span. For the sag increase to 7 meters at 50 degrees C: yes this is completely expected. Conductors are made of aluminum and steel which both expand with temperature. A temperature rise from 25 to 50 degrees C causes thermal expansion of the conductor. The conductor length increases by L x alpha x delta T where alpha for ACSR is approximately 0.000019 per degree C. Over 233 m with 25 degree rise, elongation = 233 x 0.000019 x 25 = 0.11 m. This additional slack increases the sag from 5 to approximately 7 meters as the extra length hangs lower. High temperature sag is the design limiting condition and must be verified to maintain minimum ground clearance requirements.

WHY ENGINEERS GET THIS WRONG Engineers calculate sag at installation temperature and forget to verify sag at maximum operating temperature. The maximum sag condition for ground clearance verification is always at maximum temperature, not at installation temperature.

Q99. A suspension insulator string has 4 discs. The shunt capacitance to earth from each disc metal part is 1/8 of the self-capacitance of each disc. The voltage across the bottom disc is V4. What is the relationship between V4 and V1 (top disc) and what is the string efficiency?

ANSWER Let K = shunt capacitance / self capacitance = 1/8 = 0.125. For a 4-disc string, the current flowing through each disc increases from top to bottom because each shunt capacitance adds to the current. Using the standard string analysis: V2 = V1(1 + K) = 1.125 V1. V3 = V1(1 + 3K + K^2) = V1(1 + 0.375 + 0.01563) = 1.391 V1. V4 = V1(1 + 6K + 5K^2 + K^3) = V1(1 + 0.75 + 0.078 + 0.00195) = 1.83 V1. Total string voltage V = V1 + V2 + V3 + V4 = V1(1 + 1.125 + 1.391 + 1.83) = 5.346 V1. String efficiency = V / (4 x V4) = 5.346 V1 / (4 x 1.83 V1) = 5.346 / 7.32 = 73%. This means the bottom disc carries 34% more voltage than average. String efficiency of 73% means the insulator string is only 73% as effective as it would be if voltage distributed evenly, which is why guard rings and grading rings are used at tower tops.

WHY ENGINEERS GET THIS WRONG Engineers know string efficiency should be close to 100% but rarely understand the calculation. The key insight is that the shunt capacitances to earth redirect current away from the top discs toward the bottom disc, creating unequal voltage distribution.

Q100. A 132 kV overhead line was operating normally in dry weather with no corona. After heavy rain the operators notice audible hissing and radio interference on nearby equipment, and SCADA shows slightly increased line losses. No fault has been detected. What is happening and should the line be taken out of service?

ANSWER The line is experiencing corona discharge triggered by wet weather conditions. Rain deposits water droplets on conductor surfaces which create sharp points and local field enhancements. These local concentrations of electric field exceed the critical disruptive voltage threshold at those points even though the overall line voltage has not changed. Corona creates hissing noise, ozone production, radio frequency interference (which is what is affecting nearby equipment), and measurable power loss. The line does not need to be taken out of service. Corona in wet weather on an operating 132 kV line is a known normal phenomenon and not a fault condition. The line is safe to continue operating. Actions to investigate if corona is persistent in dry weather would be: check for damaged or corroded conductors, check for any foreign objects on the conductor, and verify conductor spacing. Radio interference should be reported for engineering review of whether the conductor size or spacing needs modification at the next planned outage.

WHY ENGINEERS GET THIS WRONG Operators who have not seen corona before often mistake the hissing sound and radio interference for a developing flashover or insulation fault and initiate unnecessary line shutdowns. Corona is not a fault and does not require immediate line isolation.

Q101. A 33 kV cable feeder 10 km long is energized from a substation at night with no load connected at the far end. The remote end VT reads 34.1 kV while the local sending end is 33.0 kV. No fault alarm has operated. An operator reports an overvoltage condition and wants to trip the feeder. Is this a fault?

ANSWER No. This is the Ferranti effect, not a fault. The 10 km cable has significant distributed capacitance (cables have 10 to 30 times more capacitance per km than overhead lines). With the receiving end open, the capacitance draws leading charging current from the source. This charging current flows through the cable inductance and produces a voltage rise along the cable. The percentage rise = 34.1 - 33.0 / 33.0 x 100 = 3.3%. This is a typical Ferranti rise for a 10 km cable at 33 kV with no load. The overvoltage of 34.1 kV is 3.3% above nominal and is not a dangerous overvoltage for 33 kV equipment which is rated for 36 kV maximum. The operator should be informed that this is normal for an unloaded cable. The practical concern is for very long cables or high voltage cables where Ferranti rise can exceed equipment ratings. In this case it does not.

WHY ENGINEERS GET THIS WRONG Operators see voltage at the far end higher than sending end and immediately think something is wrong. The Ferranti effect on unloaded cables is predictable and expected. The engineering question is whether the magnitude of rise exceeds equipment ratings, not whether it exists.

Q102. A 33 kV line using solid copper conductors 25 mm diameter has a DC resistance of 0.035 ohm per km. At 50 Hz the measured resistance is 0.041 ohm per km. What is causing this and is this difference significant at 50 Hz?

ANSWER The increase from 0.035 to 0.041 ohm per km is caused by the skin effect. At 50 Hz, alternating current concentrates near the surface of the 25 mm diameter conductor, reducing the effective cross-section carrying current. The effective resistance increase = (0.041 - 0.035) / 0.035 x 100 = 17.1%. For a 25 mm diameter solid copper conductor at 50 Hz, a 15 to 20% increase in resistance due to skin effect is realistic. This is significant in power loss calculations. If a designer used DC resistance values for a solid conductor loss calculation, the actual copper losses would be 17% higher than predicted. This is why overhead line conductors use stranded ACSR construction rather than solid conductors. In stranded conductors the individual wire diameters are small (typically 2 to 4 mm) so each strand has negligible skin effect. The overall skin effect of stranded conductors is much less than solid conductors of the same total cross-section.

WHY ENGINEERS GET THIS WRONG Many engineers use the DC resistance from datasheets for 50 Hz loss calculations without applying a skin effect correction factor. For large diameter solid conductors at power frequency the error can exceed 20%.

Q103. A radial distribution feeder has a substation voltage of 11 kV and supplies three loads: 500 kW at 0.8 pf at 2 km, 300 kW at 0.9 pf at 5 km, and 200 kW at unity pf at 8 km. R of the feeder is 0.3 ohm per km. Without calculating precisely, which load causes the highest voltage drop at its terminals and why?

ANSWER The load at 8 km (200 kW, unity pf) does not cause the highest individual voltage drop at its own terminals from the substation. The cumulative effect of the first load at 2 km affects all downstream points. The voltage drop from the substation to the 8 km point depends on the total current flowing through all 8 km. However the load that causes the most severe voltage regulation is the load at 5 km carrying 300 kW at 0.9 pf combined with serving the 200 kW load beyond it. To find the worst individual contribution: at 2 km, current = 500,000 / (1.732 x 11000 x 0.8) = 32.8 A, reactive component = 32.8 x tan(arccos 0.8) = 32.8 x 0.75 = 24.6 A reactive. At 5 km, current from load 2 = 300,000 / (1.732 x 11000 x 0.9) = 17.5 A. At 8 km, current = 200,000 / (1.732 x 11000 x 1.0) = 10.5 A, zero reactive. The highest volt-drop impact per unit distance is from the lagging pf loads because they carry reactive current component which contributes (X sin phi) to the voltage drop formula. The load at 0.8 pf causes the worst per-unit contribution despite being closest to the source.

WHY ENGINEERS GET THIS WRONG Many engineers focus on the most distant load as the worst voltage drop point without recognizing that low power factor causes more volt drop per km than high power factor loads, and that the cumulative current from all loads flows through the first section.

Q104. A factory load is 800 kW at 0.65 pf lagging. The utility has penalized the factory with a power factor surcharge. The factory engineer proposes installing 600 kVAR capacitor banks. After installation, the utility meter reads 800 kW active but the reactive meter now reads 21 kVAR capacitive instead of zero or lagging. The utility says the power factor is now 0.9998 leading and the factory will still be penalized. Why is leading pf penalized?

ANSWER Reactive power = original Q lagging = P x tan phi = 800 x tan(49.46 deg) = 800 x 1.169 = 935 kVAR lagging. After 600 kVAR capacitor: new Q = 935 - 600 = 335 kVAR. That should give pf = 800/root(800^2 + 335^2) = 0.923. But the meter reads 21 kVAR capacitive, meaning the capacitors installed are rated higher than needed, approximately 935 + 21 = 956 kVAR was installed, not 600 kVAR. The factory overcompensated. Leading power factor is penalized because: when a consumer draws leading reactive current, they are injecting reactive power into the grid. This reactive injection raises the local bus voltage above normal, forcing the utility to reduce generator excitation or switch out reactive compensation equipment to maintain voltage within limits. Leading pf at the consumer end creates voltage regulation problems for the utility in the same way that lagging pf does, just in the opposite direction. Most utility tariffs penalize both lagging pf below 0.9 and leading pf below 0.98 leading.

WHY ENGINEERS GET THIS WRONG Engineers install capacitors and assume any improvement is good. Over-compensation to a leading pf actually creates voltage problems on the network and most utility tariffs penalize it. Size capacitors to achieve a slightly lagging or unity pf, never leading.

Q105. A ring distribution feeder is cut at one point for maintenance, converting it to a radial feed. The substation voltage at the cut point measured from one direction is 10.8 kV and from the other direction is 11.1 kV. This 300 V difference was zero when the ring was closed. What does this tell you about the ring feeder?

ANSWER When a ring is closed the 300 V difference drives a circulating current around the ring. The circulating current = voltage difference / total ring impedance. This circulating current adds to the load current in one section of the ring and subtracts from it in the other section. When the ring is open the actual load current in each section determines the voltage at the cut point from each direction. The 300 V difference at the open point when the ring is intact would appear as a voltage stress across any switching device connecting the two sides. Before closing the ring after this maintenance outage the engineer must check that the voltage difference is within the synchronising check relay window (typically +/- 5% of nominal which is +/- 550 V for 11 kV). 300 V is 2.7% which is within tolerance. However the phase angle across the open point must also be checked because a voltage magnitude match with a phase angle difference will still cause a large inrush current on closing. The synchronising check relay verifies both magnitude and angle before permitting ring closure.

WHY ENGINEERS GET THIS WRONG Engineers see a small voltage difference on the ring and assume closure is safe. They miss the phase angle check. A ring feeder cut at a point that has experienced network topology changes can have the two sides at significantly different angles even if voltage magnitudes match.

Q106. A feeder overcurrent relay has pickup set at 400 A primary and IDMT Normal Inverse curve with TMS = 0.3. A fault current of 2000 A flows. The relay must coordinate with a downstream relay that trips in 0.4 seconds at the same fault level. Calculate the operating time of the upstream relay and check if there is adequate grading margin.

ANSWER For IEC Normal Inverse: t = TMS x (0.14 / (M^0.02 - 1)) where M = I_fault / I_pickup = 2000 / 400 = 5. t = 0.3 x (0.14 / (5^0.02 - 1)) = 0.3 x (0.14 / (1.0353 - 1)) = 0.3 x (0.14 / 0.0353) = 0.3 x 3.966 = 1.19 seconds. Grading margin between upstream and downstream = 1.19 - 0.4 = 0.79 seconds. Standard grading margin requirement is typically 0.3 to 0.4 seconds for numerical relays (accounting for CB interrupting time of 0.06 s, relay overshoot of 0.05 s, CT error margin of 0.05 s, and safety margin of 0.1 to 0.15 s). The 0.79 second margin is more than adequate. However this margin seems excessively large. At higher fault currents the IDMT characteristic speeds up and the margin closes. The coordination should be verified at the maximum fault current at that location, not just at 2000 A.

WHY ENGINEERS GET THIS WRONG Engineers check coordination at one fault current level and declare it coordinated. IDMT coordination must be verified across the full range from minimum to maximum fault current because the margin changes at every point on the curve.

Q107. A 33 kV overhead line is protected by a distance relay. Zone 1 is set to 80% of line impedance. The line primary impedance is 10 ohm at 65 degrees. CT ratio is 200/1. VT ratio is 33000/110. Calculate the Zone 1 secondary impedance setting and explain why Zone 1 is set to 80% not 100%.

ANSWER Secondary impedance = (CT ratio / VT ratio) x primary impedance. CT ratio = 200. VT ratio = 33000/110 = 300. Secondary impedance = (200/300) x 10 = 0.667 x 10 = 6.67 ohm at 65 degrees. Zone 1 secondary setting = 80% x 6.67 = 5.33 ohm at 65 degrees. Zone 1 is set to 80% not 100% for the following reason: CT and VT measurement errors can cause the apparent impedance seen by the relay to differ from the true fault impedance by several percent. If Zone 1 were set at 100% and a fault occurred exactly at the remote bus (100% of line), CT or VT errors might cause the relay to see an apparent impedance slightly less than the true impedance, making it appear the fault is within Zone 1 when it is actually on the adjacent bus. This would cause Zone 1 to trip instantaneously for a fault that should be cleared by the remote bus protection. The 20% under-reach margin ensures Zone 1 never extends beyond the remote bus under any combination of measurement errors.

WHY ENGINEERS GET THIS WRONG Engineers sometimes set Zone 1 at exactly 100% thinking it protects the full line. Zone 1 must always under-reach to prevent overlapping with the adjacent zone and causing simultaneous instantaneous clearing of remote bus faults, which destroys selectivity.

Q108. An overcurrent relay protects a 11/0.415 kV transformer. The transformer HV rated current is 52.5 A. The relay is set to 1.2 times rated current as pickup. A motor on the LV side starts and draws 6 times its rated current of 50 A for 5 seconds during

starting. The LV current reflected to HV = 50 x 6 x (0.415/11) = 11.3 A. Will the relay trip during motor starting?

ANSWER No, the relay will not trip during motor starting. Check: overcurrent relay pickup = 1.2 x 52.5 = 63 A. Motor starting current reflected to HV = (6 x 50) x (0.415/11) = 300 x 0.0377 = 11.3 A. The reflected starting current of 11.3 A is far below the relay pickup of 63 A. The relay will not even pick up, let alone trip. However if the transformer itself is also at full load (52.5 A on HV) when the motor starts, the total HV current = 52.5 + 11.3 = 63.8 A which is just above the pickup of 63 A. In this case the relay would pick up but the IDMT time delay at 63.8/63 = 1.013 times pickup would be enormous (approaching infinity on the curve) and the relay would not trip in any practical time. The motor starting scenario is safe from the HV overcurrent relay perspective in this case.

WHY ENGINEERS GET THIS WRONG Engineers calculate motor starting current on the LV side and panic about tripping without bothering to reflect the current through the transformer ratio to check against the HV relay setting. Always work in consistent voltage levels.

Q109. During on-load testing after energizing a 33/11 kV substation, you measure the differential spill current on the 87T relay. At center tap (nominal tap 4) the spill is 0.02 pu. At tap 1 (maximum voltage) the spill is 0.09 pu. At tap 13 (minimum voltage) the spill is 0.10 pu. The relay minimum pickup is 0.2 pu. The commissioning engineer says all results are below pickup so the relay is stable. Do you agree?

ANSWER Partially agree but flag concerns. The relay is stable at all three tap positions since 0.10 pu is well below the 0.2 pu pickup. However the pattern of spill is abnormal. At center tap the spill should be near zero because the auxiliary CTs or relay settings should exactly compensate the rated voltage ratio. A spill of 0.02 pu at center tap is acceptable (within CT error limits). However the spill increasing to 0.09 and 0.10 pu at extreme taps is high. This indicates the relay is not fully compensating the voltage ratio change across the tap range. The acceptable rule is that spill at extreme taps should be comparable to each other (symmetric) and not exceed approximately 5 to 10 percent of rated current in per unit terms. The 0.09 to 0.10 pu at extreme taps consumes 45 to 50 percent of the relay pickup margin. Under any through-fault condition at extreme taps, CT errors will add to this standing spill and could push the total above 0.2 pu causing a false trip. The commissioning engineer must investigate why tap-dependent spill is so high and verify the relay tap changer compensation settings.

WHY ENGINEERS GET THIS WRONG Checking only that spill is below pickup is insufficient. The safety margin between standing spill and pickup must be adequate to absorb CT errors during through-faults. A spill already at 50% of pickup with no fault current is a red flag.

Q110. A hydroelectric plant with head H = 50 m and flow Q = 200 m^3/s has an overall efficiency of 85%. Calculate the electrical output power in MW. If the plant needs to supply 60 MW to a load 50 km away over a 132 kV line with 5% voltage regulation, what is the sending end voltage?

ANSWER Power output: P = rho x g x Q x H x efficiency. Where rho (water density) = 1000 kg/m^3, g = 9.81 m/s^2, Q = 200 m^3/s, H = 50 m, efficiency = 0.85. P = 1000 x 9.81 x 200 x 50 x 0.85 = 1000 x 9.81 x 10000 x 0.85 = 83,385,000 W = 83.4 MW. The plant can supply the required 60 MW. For the transmission voltage: receiving end VR = 132 kV (load end). Regulation = 5% = (VS - VR) / VR x 100. VS = VR x (1 + 5/100) = 132 x 1.05 = 138.6 kV. The generator step-up transformer must boost to 138.6 kV at the sending end to deliver 132 kV at the load end after the 5% line drop. The generator transformer ratio must be designed for VS = 138.6 kV, not 132 kV.

WHY ENGINEERS GET THIS WRONG Engineers design the transformer for nominal system voltage at the receiving end and forget the sending end must be higher to compensate for the line voltage drop. The transformer tap must be set for the sending end voltage, not the nominal system voltage.

Q111. A wind turbine generator is connected to a 33 kV grid through a step-up transformer. The wind speed doubles from 5 m/s to 10 m/s. A technician says the output power doubles. Is he correct?

ANSWER No. Wind power is proportional to the cube of wind speed, not linearly proportional to wind speed. P = (1/2) x rho x A x v^3 where rho is air density, A is rotor swept area, and v is wind speed. If wind speed doubles from 5 to 10 m/s, the power increases by a factor of 2^3 = 8. So the output increases 8 times, not 2 times. At 5 m/s if output is 100 kW, at 10 m/s the theoretical output is 800 kW. In practice modern wind turbines have rated power limits and control systems that pitch-regulate the blades above rated wind speed to keep output constant and prevent mechanical damage. So the 8-times theoretical increase is only achieved below rated wind speed. Above rated wind speed the output is clamped at rated power by blade pitch control.

WHY ENGINEERS GET THIS WRONG The cube law for wind power is often forgotten. A small increase in wind speed causes a large increase in power. This is why wind power output is highly variable and why wind forecasting is critical for grid operators.

Q112. A nuclear power plant is operating as a base load station. The grid operator asks it to reduce output by 30% within 5 minutes to balance a sudden drop in demand. The plant operator refuses. Why is this refusal technically justified?

ANSWER Nuclear power plants have very limited ability to follow load quickly for the following reasons. The nuclear fission reaction in the reactor core cannot be rapidly reduced without creating xenon poisoning. When reactor power is reduced, iodine-135 (a fission product) decays into xenon-

135 which is a very strong neutron absorber. This xenon-135 accumulation temporarily makes the reactor very difficult to restart or increase power for up to 40 hours after a reduction. Additionally the reactor thermal systems, steam generators, and turbines have large thermal masses and cannot be cooled down or heated up rapidly without risking thermal stress damage to the reactor vessel and steam generator tubes. A 30% power reduction in 5 minutes would violate safe operating limits for rate of change of thermal output. Nuclear plants are designed for continuous full-output base load operation. For rapid load following, gas turbines, pumped hydro storage, and demand response are the appropriate tools. The grid operator should use these flexible resources to balance the demand drop, not the nuclear station.

WHY ENGINEERS GET THIS WRONG Grid operators sometimes treat nuclear plants like gas turbines and demand rapid output changes. Nuclear plants have specific rate-of-change limits defined by their operating license and violating them risks reactor safety. This is a fundamental operational constraint, not an unwillingness to cooperate.

SECTION 22 87T TRANSFORMER DIFFERENTIAL THE TRAPS INSIDE THE RELAY LOGIC

Q113. A Dyn11 transformer 87T relay worked perfectly for 3 years. The OLTC motor was replaced during maintenance. After the motor replacement a standing Idiff of 0.19 pu appeared. No CT was touched. No relay settings were changed. No wiring was disturbed. All CTs test correctly. Engineers chased the problem for five days without finding anything. What is the non-obvious cause?

ANSWER The OLTC position encoder or cam was reassembled one mechanical step out of alignment during motor replacement. The 87T relay uses the tap position signal to apply internal ATCC (Automatic Tap-Changer Compensation) — it mathematically adjusts the expected current ratio between HV and LV sides according to the active tap. If the OLTC encoder reports tap 8 but the winding is physically on tap 7 or tap 9 due to a one-step slip when the coupling was reassembled, the relay compensates for the wrong ratio. A one-step tap error produces exactly this level of standing Idiff: for a typical 2.5% per step transformer and 20 MVA rating it produces 0.15 to 0.20 pu standing differential. Fix: measure the turns ratio at the current physical tap and compare it to the tap number displayed in the relay and SCADA. If the actual ratio corresponds to tap 7 but the system reads tap 8, re-zero the OLTC position encoder.

WHY ENGINEERS STAY STUCK Engineers assume a mechanical maintenance task like motor replacement cannot affect relay performance. The tap position feedback chain (motor shaft coupling → cam or encoder → signal to relay) is broken every time the motor coupling is disturbed and must be re-verified by turns ratio measurement after reassembly.

Q114. During 87T on-load stability check Idiff is 0.02 pu at nominal tap. Engineer raises OLTC to tap 1 (maximum voltage). Idiff rises to 0.09 pu. He lowers back to nominal and Idiff returns to 0.02 pu. The relay does not trip at 0.09 pu. He accepts the result. The senior says this is a RED FLAG and refuses to sign. Explain the danger.

ANSWER The 0.09 pu at extreme tap is not acceptable even though the relay did not trip. This standing spill consumes 45% of the 0.2 pu pickup budget before any fault current exists. During a heavy through-fault at tap 1, CT ratio errors add on top of the standing spill. A 5P20 CT under 10x rated fault current can produce approximately 0.05 to 0.10 pu additional spill from ratio error. Adding 0.09 pu standing plus 0.10 pu CT error equals 0.19 pu total — 95% of pickup. Any further imbalance from temperature drift or system asymmetry pushes the relay into false operation on an external fault. The root cause is the relay ATCC tap-correction table not perfectly matching the actual transformer turns ratio at extreme tap. Verify the relay's internal voltage ratio at tap 1 against the physically measured turns ratio at tap 1. They must agree within 0.1%.

WHY ENGINEERS STAY STUCK Seeing no trip and declaring stability is wrong. Stability means Idiff is near zero at ALL tap positions, not merely below pickup. The margin between standing spill and pickup must survive additional CT errors during through-faults.

Q115. A 87T relay trips 0.8 seconds after HV CB closes during energization. Disturbance recorder shows: first 0.8 seconds has 22% second harmonic decaying to 16%. At exactly 0.8 seconds the current suddenly becomes a sustained DC-offset sinusoid with only 4% second harmonic. Engineer A says harmonic restraint failed. Engineer B says an actual fault developed at 0.8 seconds. Who is right and how do you prove it from the disturbance recorder alone without opening the transformer?

ANSWER Engineer B is right. The transition at 0.8 seconds from a DECAYING transient to a SUSTAINED DC-offset sinusoid is the definitive signature of a fault developing during inrush — not continued inrush. Normal inrush always decays in amplitude over time. A sustained current that stops decaying and stabilizes at a constant amplitude means a fault path has been established inside the winding. The 4% harmonic content of the sustained current is low because fault current is predominantly fundamental with minimal distortion. At 4% second harmonic, which is far below the 15% blocking threshold, the harmonic restraint correctly unblocks and the relay correctly trips. Proof from the recorder: if it is inrush, the LV side CT must show near-zero current throughout (no-load energization). If it is a real fault, the LV CT will show current beginning at or just before the trip point because fault current must circulate through the LV circuit. Check the LV side current trace on the disturbance recorder. Zero LV current = inrush. Non-zero LV current = internal fault.

WHY ENGINEERS STAY STUCK Engineers who see inrush and then a trip automatically assume nuisance tripping. The waveform CHARACTER change at the trip moment is the key: decaying to sustained is not inrush continuation, it is fault development. Every transformer first-energization trip must be analysed from the disturbance recorder before resetting and re-energizing.

Q116. During 87T commissioning, you inject 25% second harmonic in Phase R. Phase R is blocked as expected. You then inject a fault current in Phase Y with zero harmonic. You expect Phase Y to trip immediately. It does NOT trip. Your colleague says the harmonic blocking is faulty on Phase Y. Is he right?

ANSWER No. This is correct relay operation. Cross-blocking is active: when any phase exceeds the harmonic restraint threshold, ALL three phases are blocked from tripping, not just the phase containing harmonics. This is intentional design to prevent the relay from issuing a split-phase trip (Phase Y trips while Phase R is blocked as inrush) because 87T always trips all phases together or not at all. The test of cross-blocking is: Phase R has harmonic above threshold, Phase Y has a fault condition below threshold. Correct relay behaviour: Phase Y does NOT trip while Phase R harmonic is above threshold. Once you remove the harmonic from Phase R (drop below 15%), the relay unblocks and Phase Y trips immediately. If Phase Y trips while Phase R harmonic is still above 15%, THAT is a cross-blocking failure.

WHY ENGINEERS STAY STUCK Cross-blocking is invisible in single-phase tests. Engineers who test phases independently never encounter it. The test only reveals itself when harmonic is injected in one phase while a fault condition is simultaneously present in another phase.

SECTION 23 CT SECONDARY CIRCUITS HIDDEN WIRING FAULTS THAT LURK FOR YEARS

Q117. After commissioning a 132 kV feeder, the overcurrent relay shows Phase R current always 2-3% higher than Phase Y and Phase B under balanced load. A clamp meter at the relay terminals shows all three phases equal within 0.5%. The relay display still shows Phase R 2-3% high consistently. The engineer replaces the Phase R CT. The problem remains unchanged. What is the actual cause?

ANSWER There is a ground loop in the Phase R CT secondary circuit path to the relay input. The clamp meter measures only conductor current (CT secondary current). The relay input measures conductor current plus any current flowing through an unintended parallel ground path that forms a closed loop through the panel earth bars. The 2-3% excess at 150 A balanced load = 3 to 4.5 A ground loop current — far too large for ratio error but entirely consistent with a low-impedance parallel earth path created by two earth connections on the same CT circuit. This explains why replacing the CT made no difference: the CT was never the problem. Diagnostic: with the relay input disconnected, measure the insulation resistance of the Phase R CT secondary circuit from terminal to earth using 500 V Megger while leaving all earth connections intact. A low IR reading confirms an unintended second earth point. Locate it by disconnecting earth points one at a time while monitoring IR.

WHY ENGINEERS STAY STUCK When a relay displays higher current than the clamp meter confirms is flowing, engineers assume relay measurement error or CT ratio error and replace hardware. A clamp meter cannot detect ground loop current because it only measures the conductor inside the clamp. The relay however measures all current arriving at its input including any that re-routes through ground paths.

Q118. You test CT ratio at 100% rated current: ratio error minus 0.3%, within 5P20 limit. You then measure CT winding resistance. You return to re-verify the ratio test: now it reads plus 1.8% on the same CT with nothing changed. Why and what do you do?

ANSWER The winding resistance test injected DC current through the CT secondary winding, which magnetized the core with residual flux. When AC ratio testing is then performed on a magnetized core, the core operates on a shifted B-H characteristic: the magnetizing current is larger and has different phase angle, directly changing both the ratio error and phase displacement. The shift from minus 0.3% to plus 1.8% is entirely consistent with core magnetization from the preceding DC test. Per NEDC ESCM-2025 Section 3.4 (CT Winding Resistance): after completing the winding resistance test the CT must be demagnetized before any subsequent accuracy measurement. Demagnetization: apply variable AC voltage to the secondary, raise above knee-point excitation, then SLOWLY reduce continuously to zero. Never switch off abruptly. After demagnetization, repeat the ratio test — it will return to minus 0.3%.

WHY ENGINEERS STAY STUCK DC tests before ratio tests without demagnetization is the single most common reason CT ratio results change between repeated measurements. The test sequence is: ratio test first, then winding resistance, then demagnetize, then final confirming ratio test. Skipping demagnetization invalidates the commissioning record.

Q119. You inject 400 A primary on a 400/1 CT and measure 1.005 A at the relay terminal. Ratio error is plus 0.5%, within spec. You are about to sign. The senior asks: is this measurement from the correct CT core? You say the wiring matches the drawings. What specific additional test does he mean?

ANSWER The senior wants end-to-end core identity confirmation. Most protection CTs have 2-4 separate secondary cores (Core 1 = 5P20, Core 2 = 0.5 metering, Core 3 = 0.2 billing) all wound on the same primary and sharing the same terminal box. If the test leads were clipped to Core 2 (metering) terminals instead of Core 1 (protection) terminals, the ratio test confirms Core 2 only. The protection relay connected to Core 1 was never verified. The core identity test: with all CT secondaries connected to their service devices (relay, meter, energy meter), inject 400 A primary and simultaneously measure the current appearing at the protection relay input. If the relay reads 1.005 A AND the metering panel reads the same (if sharing a core) or zero (if on separate cores), the protection relay is confirmed connected to the verified core. This test catches crossed terminal connections that look correct on a drawing but are wired to the wrong physical tap.

WHY ENGINEERS STAY STUCK A ratio test at the CT terminal box proves the core in the test loop is healthy. It proves nothing about which physical device is connected to which core. Only simultaneous end-to-end measurement with all service devices connected confirms complete core identity.

SECTION 24 DISTANCE RELAY THE k0 TRAP AND WHAT LOOKS LIKE A REACH PROBLEM

Q120. All phase-to-phase distance zone tests (R-Y, Y-B, B-R) pass perfectly. All phase-to-earth zone tests (R-E, Y-E, B-E) fail at 50% of expected reach. The commissioning engineer doubles the zone reach setting and the earth tests pass. The senior rejects this fix. Why is doubling the reach dangerous and what is the real cause?

ANSWER The real cause is k0 (zero-sequence residual compensation factor) is set to zero. For earth faults the relay measures the loop impedance as Z_measured = V_phase / (I_phase + k0 x I_residual). If k0 = 0 the relay ignores the zero-sequence component. For a typical 33 kV line with Z0 = 3Z1: the actual earth fault loop impedance is (2Z1 + Z0)/3 = 5Z1/3 = 1.67 Z1. The relay without k0 measures only Z1. So the relay sees a fault at 0.75 of the line (actual loop = 0.75 x 1.67 x Z1) as though it is at 0.75 x 1.00 x Z1 = 45% of reach instead of 75%. This explains the 50% observation. The correct fix is to calculate and enter k0 = (Z0 - Z1)/(3 x Z1). Doubling the zone reach is dangerous because it only works for faults with a specific earth resistance. Under different soil conditions, fault resistance, or system configurations the reach will be either too long (overreaching into next zone) or still too short. A wrongly compensated earth fault zone cannot be made correct by adjusting reach.

WHY ENGINEERS STAY STUCK Phase zones pass, earth zones fail at 50% reach — this is the definitive k0 = 0 fingerprint. Engineers who adjust reach to fix the symptom leave the relay with completely wrong directional and impedance characteristics for all real earth fault conditions in service.

Q121. A 132 kV line has operated normally for 10 years with a distance relay. A second circuit is installed on the same tower. Immediately after energizing the second circuit, the first relay starts spuriously operating Zone 2 for external faults on the second circuit. No settings changed on the first relay. Why does this happen only for earth faults on the second circuit and not for any other faults?

ANSWER Mutual zero-sequence coupling between the two circuits on the shared tower structure. When an earth fault occurs on the second circuit, zero-sequence current flows through the second circuit conductors and the earth return path. This zero-sequence current induces a mutual zero-sequence EMF (Vm) into the first circuit through the shared tower and earth wire. This Vm appears at the first relay's voltage input. For a specific fault direction and location, Vm reduces the first relay's apparent measured loop impedance below the actual distance to the fault on the FIRST circuit, making the first relay believe there is a fault within Zone 2 on its own line when there is no such fault. This only affects earth faults (zero-sequence coupling only — positive and negative sequence coupling is negligible) and only when the fault is on the parallel circuit (the source of Vm). The fix: measure the mutual zero-sequence impedance Zm between the two circuits using the sequence impedance test method (CSD CM_P13-12). Enter the Zm correction (km0 or mutual compensation factor) into both distance relays. The corrected k0_effective = (Z0 + Zm - Z1) / (3 x Z1).

WHY ENGINEERS STAY STUCK Engineers spending weeks investigating CT issues, relay settings, and VT problems after a parallel circuit is added miss the most obvious correlation: the problem started precisely when the second circuit was energized and only occurs for earth faults on that circuit. Mutual coupling is the only mechanism that connects these two observations.

Q122. A distance relay correctly operates Zone 1 for a three-phase fault at 10% of the line in secondary injection testing. The relay measurement display confirms the same 10% location for a single-phase earth fault. Zone 1 correctly shows the fault within its reach. But the relay does NOT trip for the single-phase test. What is blocking the operation that is invisible during phase fault testing?

ANSWER The VT Fuse Failure (VTFF) supervision logic is blocking the single-phase Zone 1 operation. During single-phase injection, only Phase R voltage is reduced while Phase Y and Phase B remain at full nominal voltage. This asymmetric voltage pattern (one phase depressed, two phases healthy, with current only in the depressed phase) is identical to the signature of a blown VT fuse in Phase R — a common real situation the relay is designed to detect and use to block operation. For the three-phase test, all three voltages are simultaneously reduced with all three currents flowing — this symmetric pattern does not trigger VTFF. The VTFF blocking is entirely correct behaviour: if you inject a three-phase fault test using a proper test method that simultaneously applies voltage and current, Zone 1 operates. If you inject a single-phase fault with only one phase voltage reduced while the other two remain at nominal (a common simplification in secondary injection testing), the VTFF sees it as a blown VT fuse and blocks the zone operation. The fix for testing: in single-phase injection, either also depress the pre-fault voltage on the faulted phase correctly with memory voltage management, or temporarily disable VTFF blocking in the test mode to verify the zone characteristic, then re-enable it.

WHY ENGINEERS STAY STUCK The relay display showing the correct impedance measurement while the relay does not trip is the most confusing scenario in distance relay testing. Measurement elements and output elements are independent. The VTFF supervision is an output blocking logic that is invisible to the measurement display.

SECTION 25 REF HIGH-IMPEDANCE THE CALCULATION MOST ENGINEERS GET WRONG

Q123. REF scheme data: CT ratio 400/1, Vk = 380 V, RCT = 1.8 ohm, lead resistance RL = 5.0 ohm loop, max through-fault 8000 A primary (20 A secondary), relay current pickup Is = 0.1 A. An engineer calculates Rstab = Vk/2 divided by Is = 190/0.1 = 1900 ohm and enters this. The senior says this setting may cause instability. Is the setting wrong? Show your calculation.

ANSWER Step 1 — stability constraint: V_stab = I_fault_sec x (RCT + RL) = 20 x (1.8 + 5.0) = 20 x 6.8 = 136 V. The relay must operate ABOVE 136 V to be stable (otherwise the relay will pick up on external through-faults when one CT saturates). Step 2 — non-saturation constraint: relay operating voltage must not exceed Vk/2 = 190 V, otherwise the healthy CTs saturate, destroying the stability assumption. At Rstab = 1900 ohm: relay operating voltage = Is x Rstab = 0.1 x 1900 = 190 V. This is exactly at the Vk/2 boundary. It is technically within both constraints but with zero safety margin. The concern: if any CT in the zone has a knee-point 5% below specified (minimum IEC tolerance is minus 5%), Vk could be as low as 361 V and Vk/2 = 180.5 V. Then 190 V exceeds 180.5 V and stability is lost. A safe setting uses V_operating = 1.5 x V_stab = 1.5 x 136 = 204 V. But 204 V exceeds Vk/2 = 190 V. This means with the given parameters, you CANNOT achieve 1.5x stability margin while staying below Vk/2. The scheme needs higher Vk CTs or reduced lead resistance. The engineer's setting is not wrong mathematically but it is at the limit where any CT knee-point tolerance variation causes instability.

WHY ENGINEERS STAY STUCK Engineers know Rstab = V / Is but do not know that V must satisfy BOTH a lower bound (stability: above V_stab) AND an upper bound (non-saturation: below Vk/2). Satisfying one constraint while violating the other is a silent design failure.

Q124. During REF sensitivity test: Phase R CT reversed, neutral CT in normal position, 3-phase 415 V supply applied. You measure 0.15 A through the Metrosil and 68 V across the stabilizing resistor (Rstab = 600 ohm, relay pickup = 0.1 A). You calculate V = 0.15 x 600 = 90 V which exceeds the relay pickup voltage of 60 V. The relay DOES NOT trip. The trip link is confirmed IN. What is wrong with the calculation?

ANSWER The calculation uses the Metrosil current (0.15 A total) as if it flows entirely through Rstab. It does not. The relay operating element, Rstab, and Metrosil are all in PARALLEL across the summation bus. At 68 V: current through Rstab = 68/600 = 0.113 A. Current through the relay element = 68/Zrelay (relay impedance is high but not infinite). Current through Metrosil = remainder. The TOTAL current = 0.15 A is the SUM of all three parallel branches. The current through the relay element is much less than 0.15 A. If the relay current element pickup is 0.1 A and the relay element draws (for example) 0.08 A of the 0.15 A total, the relay does not pick up because its own current is 0.08 A, below the 0.1 A threshold. The correct measurement: measure current through the relay element terminal itself (not Rstab, not Metrosil) and compare it to the 0.1 A relay current pickup. Alternatively measure the voltage across the relay terminal (68 V) and compare to the relay VOLTAGE pickup setting (which should be Is x Rstab = 0.1 x 600 = 60 V). At 68 V across the relay the voltage pickup should operate. If it still does not, the relay voltage pickup setting has been entered incorrectly in the relay configuration.

WHY ENGINEERS STAY STUCK In a parallel circuit the measured total current through the Metrosil does not equal the current through any individual branch. Engineers who use Metrosil current multiplied by Rstab to predict relay behaviour are calculating a fictional voltage that does not match what any element in the circuit experiences.

Q125. A 33 kV feeder earth fault relay shows IN = 0.8 A under perfectly balanced three-phase load of 150 A per phase. No earth fault exists. Engineer 1 says the neutral CT has ratio error. Engineer 2 says all phase CTs have the same direction of ratio error and the sum appears as residual. Your senior says both are wrong and the cause is something entirely different. What does the senior mean?

ANSWER The transformer star point is solidly grounded and serves an 11 kV distribution network with single-phase residential and commercial loads. In a 33/11 kV Dyn11 or YNyn transformer, the 33 kV star point neutral CT is directly in the neutral-to-earth connection. Real zero-sequence current flows through the transformer neutral continuously because the LV distribution network has unbalanced single-phase load distribution — Phase R may be more heavily loaded than Phase Y or Phase B. This zero-sequence unbalance current returns through the transformer neutral connection to earth. The neutral CT measures this real earth return current correctly. It is not a CT error. It is real fundamental zero-sequence current caused by LV network load unbalance. 0.8 A at the 33 kV CT level (400/1) corresponds to 320 A primary neutral current, which is entirely consistent with typical LV distribution load unbalance. The engineer's response should be: check the LV network phase loading balance, set the earth fault relay pickup above the standing neutral current level to avoid nuisance operation, and consider specifying a minimum operating current margin above the maximum expected load-unbalance neutral current.

WHY ENGINEERS STAY STUCK Engineers who see unexpected neutral current always assume instrument error. On transformer incomer CTs, unexpected but consistent neutral current is more likely real load-unbalance current than CT measurement error. Replacing CTs or adjusting settings without diagnosing the actual source produces endless cycles of re-investigation.

Q126. On-load impedance check shows Z = 45 ohm at 70 degrees on a 132 kV line. Expected is 43 ohm at 72 degrees. Close enough. Engineer accepts and moves on. Senior says look at the measurement for 10 minutes. The impedance slowly drifts from 45 ohm to 39 ohm over 5 minutes then slowly returns. Load is perfectly stable. What is wrong and why is this dangerous?

ANSWER There is an intermittent loose connection in the VT secondary circuit. Since Z = V/I and the load current I is constant, a drifting Z means the relay's measured V is drifting. A VT secondary terminal with a loose screw varies its contact resistance as the panel undergoes thermal cycling (heats up over hours after energization, contacts expand and contract). At 45 ohm the relay is seeing approximately 95% of nominal VT voltage. At 39 ohm it is seeing approximately 83% of nominal VT voltage. The 13% reduction in apparent impedance means the apparent load impedance is drifting toward Zone 1. For a 132 kV line protected by Zone 1 set to 80% of line secondary impedance, Zone 1 reach is typically 25 to 50 ohm secondary depending on line length. If load impedance drifts below Zone 1 reach, the relay trips the line under normal load — a load-shedding trip with no preceding fault. The danger: this produces no alarm whatsoever. No VT fail alarm triggers because the voltage reduction is gradual and does not cross the VTFF threshold. The relay shows a drifting number that appears within the normal range on a snapshot check. Only sustained observation reveals the drift. Action: check every VT secondary terminal and test switch contact in the Phase R circuit under live conditions.

WHY ENGINEERS STAY STUCK A snapshot on-load impedance check lasting 30 seconds cannot detect intermittent contact resistance that takes minutes to develop. Impedance measurements must be monitored for several minutes before being accepted. Any drift in impedance under stable load is a VT circuit fault regardless of how small the drift appears.

Q127. Two 20 MVA transformers operate normally in parallel for two weeks after commissioning. Then suddenly both OLTCs start hunting continuously: tapping up and down every 30 to 60 seconds indefinitely even with stable bus voltage and stable load. Nothing was changed. The operators restart the AVR system and the hunting stops for one hour then restarts. What was not tested during commissioning that predicted this failure?

ANSWER The MCC (Minimum Circulating Current) circulating current bias polarity was never verified under actual circulating current conditions. During normal parallel operation with matching tap positions, no circulating current flows and the MCC bias has no effect — which is why the system appeared stable for two weeks. As the two transformers aged over two weeks, minor differences in their winding resistance temperature characteristics caused slightly different impedances, producing a small tap mismatch and a small circulating current. Once circulating current appeared, the MCC bias polarity error revealed itself: instead of both AVRs receiving OPPOSITE commands (one Raise, one Lower) to converge the taps and reduce circulating current, both AVRs received the SAME command in the WRONG direction. Both raise simultaneously, increasing the voltage difference, increasing circulating current, triggering larger bias, both raise again — a positive feedback loop. The hunting stops temporarily after an AVR restart because the tap position differential resets to zero momentarily. Per NEDC ESCM-2025 AVR Test Case 6 (MCC ON), the required test creates a deliberate tap difference, applies the MCC scheme, and verifies that the two AVRs issue OPPOSITE tap commands that converge to balance. This test was not performed during commissioning.

WHY ENGINEERS STAY STUCK A parallel transformer system that passes all commissioning tests under zero circulating current conditions can still have the MCC bias wired in the wrong direction. The error is undetectable until actual circulating current appears in service, which may take weeks or months after commissioning.

SECTION 27 CBF AND LOCKOUT LOGIC THAT WORKS IN TESTS BUT FAILS IN SERVICE

Q128. A CBF relay times out correctly and fires Stage 1 backup trip in testing. Six months later a real CB failure occurs. The primary relay trips the CB. The CB fails to open (contacts welded). CBF Stage 1 fires as expected. But it only trips the bus coupler — it does NOT trip the bus incomer CB. The CBF wiring to both the bus coupler and bus incomer was confirmed correct. What is the cause?

ANSWER The CBF relay output contact and the bus incomer trip coil are powered from DIFFERENT DC supply buses. In a dual-DC system (Bus A and Bus B), the CBF relay is supplied from DC Bus A (its protection panel DC source). The bus coupler CB is also supplied from DC Bus A so the trip circuit completes. The bus incomer CB is in a different panel supplied from DC Bus B. When the CBF contact closes, it connects DC Bus A positive through the CBF contact to the bus incomer trip coil. But the trip coil return path goes through DC Bus B negative, which is isolated from DC Bus A. The circuit is open. No trip current flows. During commissioning testing, the engineer powered the test circuit from the same DC source as the CBF relay, completing the circuit — the test passed. In service, the bus incomer operates from a different DC source. The fix: in multi-DC-supply substations, verify that all elements in every trip chain share the same DC supply polarity, or use an interposing relay that converts the CBF contact output to the appropriate DC supply bus for each remote trip coil. Per NEDC ESCM-2025 Final Trip Test (CM_P18), the trip test must use the actual in-service DC supply connections, not a bench DC supply.

WHY ENGINEERS STAY STUCK DC supply incompatibility between a relay output contact and a remote trip coil is the most common cause of protection schemes that work perfectly in commissioning tests but fail in real service. Every relay test that uses a bench DC power supply instead of the actual panel DC supply has a hidden assumption that must be explicitly verified.

Q129. A transformer CBF relay has a current-check threshold set at 0.1 pu (10% of rated). The transformer is operating at 8% of rated load (16% of rated current on the primary HV side). A Buchholz relay operates and trips the HV and LV CBs via the 87T relay. The HV CB fails to open. The CBF timer starts. After 150 ms the CBF does NOT fire. Why?

ANSWER The CBF current-check threshold of 0.1 pu equals 10% of rated. The transformer load current of 8% of rated is 16% of rated current, which corresponds to 0.16 pu. Wait — re-examine: if rated current is I_rated and the load is at 8% of transformer capacity, the actual load current as a fraction of rated current depends on the power factor. At 0.9 pf: I_load = 0.08 x MVA / (root3 x kV) = 8% of rated current of transformer. The per-unit value of load current = 0.08 pu. The CBF current threshold = 0.10 pu. The load current of 0.08 pu is BELOW the CBF threshold of 0.10 pu. The CBF sees current below its operating threshold and concludes the CB must be already open (because no fault current is flowing above threshold). The CBF timer resets immediately without issuing any backup trip, even though the HV CB contacts have welded shut. This is precisely the failure mode that the LOW-CURRENT CBF MODE (using CB 52a position contact instead of current check) was designed to prevent. For Buchholz, PRD, WTI, and OTI initiations the transformer may be at ANY load level including very light load. The low-current CBF mode must be configured for all mechanical protection initiations. Per CSD CM_P15-2 item 7: CBF for mechanical protection must use low-current mode.

WHY ENGINEERS STAY STUCK Engineers set the CBF threshold at a level they consider conservatively low (0.1 pu = 10% of rated) without realising transformers frequently operate at even lighter loads. Any CBF threshold above the minimum operating load level creates a blind spot that allows CB failure to go undetected.

SECTION 28 ENERGIZATION ONE CHANCE TO GET IT RIGHT

Q130. Pre-energization checklist for a 132 kV transformer is complete: PI passes, turns ratio correct, vector group confirmed, FRA matches factory, oil dielectric above 60 kV, Buchholz fitted, all relays set. Engineer signs and proceeds to energize. The 87T trips 0.2 seconds after energization. Disturbance recorder shows large asymmetric current, 2nd harmonic starting at 24% and falling rapidly to 11% within 0.15 seconds before the trip at 0.2 seconds. There was no recent short-circuit incident. What single missed pre-energization step caused this?

ANSWER The transformer core was not demagnetized after the winding resistance test. Per NEDC ESCM-2025 section on winding resistance test (page noting demagnetization): applying DC current during winding resistance testing magnetizes the transformer core. Residual DC magnetization causes the transformer to enter deep saturation on the FIRST half-cycle of AC energization when the AC flux adds to the residual flux. This produces an inrush current with two specific characteristics that defeat harmonic blocking: peak amplitude 2 to 4 times higher than normal inrush, and second harmonic content that decays faster than normal inrush because the waveform enters deep saturation rapidly (highly peaked waveform with lower harmonic-to-fundamental ratio). Normal inrush takes 1 to 5 seconds for second harmonic to decay below 15%. Inrush from a pre-magnetized core can drop below 15% second harmonic within 0.1 to 0.2 seconds while the inrush current is still large. The relay is presented with large Idiff and insufficient harmonic to block — a correct trip by the relay on what is technically inrush. Demagnetization procedure: inject AC into the secondary, raise voltage above the knee-point, then slowly and continuously reduce to zero. Never switch off abruptly.

WHY ENGINEERS STAY STUCK Demagnetization is listed in every CT and transformer testing manual but is consistently skipped because its consequences are invisible until energization. A commissioning checklist that confirms all tests were done is not complete without confirming that demagnetization was performed as the LAST step before energization.

Q131. Phasing check before paralleling two 33 kV sources: engineer energizes Source 1, records R = 0 deg, Y = -120 deg, B = +120 deg from bus VT. De-energizes Source 1. Energizes Source 2, records R = 0 deg, Y = -120 deg, B = +120 deg from same bus VT. Declares both sources in phase. Closes bus coupler. A massive current flows and both incomers trip. How is it possible that identical VT readings mean the sources were NOT in phase?

ANSWER The phasing test measured both sources sequentially from the SAME bus VT. The bus VT measures the voltage of whichever source is currently energizing the bus. When Source 1 drives the bus it drives it to its own phase angle. When Source 2 drives the same bus it drives it to ITS own phase angle. In both cases the bus VT reads zero degrees for R-phase because it is always reading the angle of the active source referenced to itself. This test is physically incapable of detecting a phase displacement between the two sources. If Source 1 is at 0 degrees absolute and Source 2 is at 25 degrees absolute, the bus VT reads 0 degrees in both cases. The actual 25-degree phase difference only appears when both sources are simultaneously present across an open point. The correct method: with Source 1 energizing the bus, use a dual-channel voltage meter or the synchrocheck relay live display to measure Source 1 bus voltage on one channel and Source 2 incomer voltage (before the coupler CB) on the second channel simultaneously. The ANGLE DIFFERENCE between these two simultaneous measurements is the actual phase displacement. The synchrocheck relay specifically measures this difference and shows it as delta-V and delta-angle across its open CB terminals.

WHY ENGINEERS STAY STUCK Sequential measurements from the same reference point are physically incapable of detecting phase displacement between two independent sources. This is not a measurement accuracy issue — it is a method error. Any phasing test that does not simultaneously measure both sources from a common reference cannot confirm synchronism.

END OF DOCUMENT

Total Questions: 131 Total Sections: 28

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