ELECTRICAL DESIGN GUIDE ACCORDING TO IEC STANDARD

OPEN ELECTRICAL

Open Electrical is a resource for electrical (power systems) engineers, aimed at bridging the gap between what you learn at engineering school and what you need to know in industry.

Draft

OpenElectrical

Open Electrical is a resource for electrical (power systems) engineers, aimed at bridging the gap between what you learn at engineering school and what you need to know in industry.

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Open Electrical: About

From Open Electrical

Open Electrical is a free, independent electrical (power systems) engineering design resource for industry practitioners. It is aimed at bridging the gap between what is taught at engineering school and what is needed to practice effectively in industry.

Industry practitioners are normally busy people and when they need information, it's usually for something related to what they are doing right then and there. However, their requirements will depend on how deep or broad they need the information to be. For example, one engineer may need to know something very specific, like what PETP stands for, while another may require something broader, like how to perform a touch and step potential calculation.

The philosophy of Open Electrical is to provide all of this information using a layered "onion" approach. The top layer (e.g. the guide to electrical cables) is very broad and provides general information about a topic with links to more specific articles. It's good as a starting point on a topic. But as you peel back the layers, the articles become deeper and more specialized.

Recommended Books

The following books are those that we recommend as essential to an electrical engineer's library:

- Network Protection and Automation Guide, Alstom - a classic power systems protection guide that is now freely available online (registration required)
- Electric Cables Handbook, BICC cables (edited by G. F. Moore) - comprehensive book about cables mainly from a British / European perspective
- Handbook of Electric Power Calculations, H. W. Beaty - good range of electrical power calculations from the very simple to the more involved. Biased towards North America.
- High Voltage Engineering & Testing, H. M. Ryan - excellent overivew of high voltage equipment theory and testing techniques (based on an IEE lecture series)
- Handbook of Photovoltaic Science and Engineering, A. Luque and S. Hegedus - quite possibly the definitive reference book on solar photovoltaic engineering, covering everything from the theory of different PV cells and how they are manufactured, to the engineering design and modelling of PV systems
- Linden's Handbook of Batteries, T. Reddy - arguably the most comprehensive book on battery technology
- Electric Machinery, A. E. Fitzgerald et al - clear and detailed exposition of electrical machine fundamentals
- J&P Transformer Book, M. Heathcote - the most complete book on transformers that was first published in 1925 and has been regularly updated since then

Load Schedule

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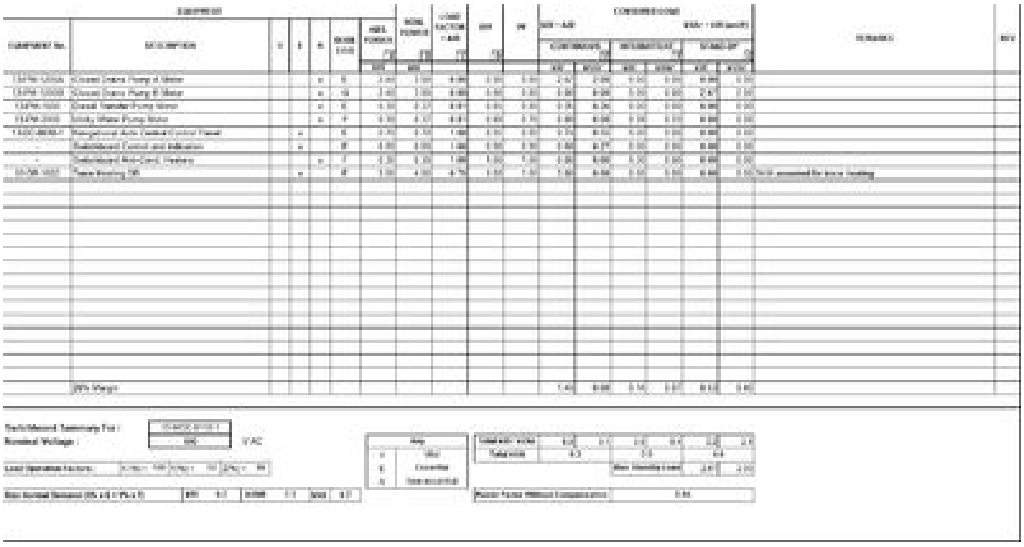
Introduction



Example of an electrical load schedule

The electrical load schedule is an estimate of the instantaneous electrical loads operating in a facility, in terms of active, reactive and apparent power (measured in kW, kVAR and kVA respectively). The load schedule is usually categorized by switchboard or occasionally by sub-facility / area.

Why do the calculation?

Preparing the load schedule is one of the earliest tasks that needs to be done as it is essentially a pre-requisite for some of the key electrical design activities (such as equipment sizing and power system studies).

When to do the calculation?

The electrical load schedule can typically be started with a preliminary key single line diagram (or at least an idea of the main voltage levels in the system) and any preliminary details of process / building / facility loads. It is recommended that the load schedule is started as soon as practically possible.

Calculation Methodology

There are no standards governing load schedules and therefore this calculation is based on generally accepted industry practice. The following methodology assumes that the load schedule is being created for the first time and is also biased towards industrial plants. The basic steps for creating a load schedule are:

- Step 1: Collect a list of the expected electrical loads in the facility
- Step 2: For each load, collect the electrical parameters, e.g. nominal / absorbed ratings, power factor, efficiency, etc
- Step 3: Classify each of the loads in terms of switchboard loca on, load duty and load cri cality
- Step 4: For each load, calculate the expected consumed load
- Step 5: For each switchboard and the overall system, calculate operating, peak and design load

Step 1: Collect list of loads

The first step is to gather a list of all the electrical loads that will be supplied by the power system affected by the load schedule. There are generally two types of loads that need to be collected:

- Process loads - are the loads that are directly relevant to the facility. In factories and industrial plants, process loads are the motors, heaters, compressors, conveyors, etc that form the main business of the plant. Process loads can normally be found on either Mechanical Equipment Lists or Process and Instrumentation Diagrams (P&ID's).

- Non-process loads - are the auxiliary loads that are necessary to run the facility, e.g. lighting, HVAC, utility systems (power and water), DCS/PLC control systems, fire safety systems, etc. These loads are usually taken from a number of sources, for example HVAC engineers, instruments, telecoms and control systems engineers, safety engineers, etc. Some loads such as lighting, UPS, power generation auxiliaries, etc need to be estimated by the electrical engineer.

Step 2: Collect electrical load parameters

A number of electrical load parameters are necessary to construct the load schedule:

- **Rated power** is the full load or nameplate rating of the load and represents the maximum continuous power output of the load. For motor loads, the rated power corresponds to the standard motor size (e.g. 11kW, 37kW, 75kW, etc). For load items that contain sub-loads (e.g. distribution boards, package equipment, etc), the rated power is typically the maximum power output of the item (i.e. with all its sub-loads in service).

- **Absorbed power** is the expected power that will be drawn by the load. Most loads will not operate at its rated capacity, but at a lower point. For example, absorbed motor loads are based on the mechanical power input to the shaft of the driven equipment at its duty point. The motor is typically sized so that the rated capacity of the motor exceeds the expected absorbed load by some conservative design margin. Where information regarding the absorbed loads is not available, then a load factor of between 0.8 and 0.9 is normally applied.

- **Power factor** of the load is necessary to determine the reactive components of the load schedule. Normally the load power factor at full load is used, but the power factor at the duty point can also be used for increased accuracy. Where power factors are not readily available, then estimates can be used (typically 0.85 for motor loads >7.5kW, 1.0 for heater loads and 0.8 for all other loads).

- **Efficiency** accounts for the losses incurred when converting electrical energy to mechanical energy (or whatever type of energy the load outputs). Some of the electrical power drawn by the load is lost, usually in the form of heat to the ambient environment. Where information regarding efficiencies is not available, then es mates of between 0.8 and 1 can be used (typically 0.85 or 0.9 is used when efficiencies are unknown).

Step 3: Classify the loads

Once the loads have been identified, they need to be classified accordingly:

Voltage Level

What voltage level and which switchboard should the load be located? Large loads may need to be on MV or HV switchboards depending on the size of the load and how many voltage levels are available. Typically, loads <150kW tend to be on the LV system (400V - 690V), loads between 150kW and 10MW tend to be on an intermediate MV system (3.3kV - 6.6kV) where available and loads >10MW are usually on the HV distribution system (11kV - 33kV). Some consideration should also be made for grouping the loads on a switchboard in terms of sub-facilities, areas or sub-systems (e.g. a switchboard for the compression train sub-system or the drying area).

Load duty

Loads are classified according to their duty as continuous, intermittent and standby loads:

1) **Continuous** loads are those that normally operate con nuously over a 24 hour period, e.g. process loads, control systems, lighting and small power distribution boards, UPS systems, etc

2) **Intermittent** loads that only operate a frac on of a 24 hour period, e.g. intermi ent pumps and process loads, automatic doors and gates, etc

3) **Standby** loads are those that are on standby or rarely operate under normal conditions, e.g. standby loads, emergency systems, etc

Note that for redundant loads (e.g. 2 x 100% duty / standby motors), one is usually classified as continuous and the other classified as standby. This if purely for the purposes of the load schedule and does not reflect the actual operating conditions of the loads, i.e. both redundant loads will be equally used even though one is classified as a standby load.

Load criticality

Loads are typically classified as either normal, essential and critical:

1) **Normal** loads are those that run under normal operating conditions, e.g. main process loads, normal lighting and small power, ordinary office and workshop loads, etc

2) **Essential** loads are those necessary under emergency conditions; when the main power supply is disconnected and the system is being supported by an emergency generator, e.g. emergency lighting, key process loads that operate during emergency conditions, fire and safety systems, etc

3) **Critical** are those critical for the operation of safety systems and for facilitating or assisting evacuation from the plant, and would normally be supplied from a UPS or battery system, e.g. safety-critical shutdown systems, escape lighting, etc

Step 4: Calculate consumed load

The consumed load is the quantity of electrical power that the load is expected to consume. For each load, calculate the consumed active and reactive loading, derived as follows:

$$P_l = \frac{P_{abs}}{\eta}$$

$$Q_l = P_l \sqrt{\frac{1}{\cos^2 \phi} - 1}$$

Where P_l is the consumed active load (kW)

Q_l is the consumed reactive load (kVAr)

P_{abs} is the absorbed load (kW)

η is the load efficiency (pu)

$\cos \phi$ is the load power factor (pu)

Notice that the loads have been categorized into three columns depending on their load duty (continuous, intermittent or standby). This is done in order to make it visually easier to see the load duty and more importantly, to make it easier to sum the loads according to their duty (e.g. sum of all continuous loads), which is necessary to calculate the operating, peak and design loads.

Step 5: Calculate operating, peak and design loads

Many organizations / clients have their own distinct method for calculating operating, peak and design loads, but a generic method is presented as follows:

Operating load

The operating load is the expected load during normal operation. The operating load is calculated as follows:

$$OL = \sum L_c + 0.5 \times \sum L_i$$

Where OL is the operating load (kW or kVAr)

$\sum L_c$ is the sum of all continuous loads (kW or kVAr)

$\sum L_i$ is the sum of all intermittent loads (kW or kVAr)

Peak load

The peak load is the expected maximum load during normal operation. Peak loading is typically infrequent and of short duration, occurring when standby loads are operated (e.g. for changeover of redundant machines, testing of safety equipment, etc). The peak load is calculated as the larger of either:

$$PL = \sum L_c + 0.5 \times \sum L_i + 0.1 \times \sum L_s$$

or

$$PL = \sum L_c + 0.5 \times \sum L_i + L_{s,max}$$

Where PL is the peak load (kW or kVAr)

$\sum L_c$ is the sum of all continuous loads (kW or kVAr)

$\sum L_i$ is the sum of all intermittent loads (kW or kVAr)

$\sum L_s$ is the sum of all standby loads (kW or kVAr)

$L_{s,max}$ is the largest standby load (kW or kVAr)

Design load

The design load is the load to be used for the design for equipment sizing, electrical studies, etc. The design load is generically calculated as the larger of either:

$$DL = 1.1 \times OL + 0.1 \times \sum L_s$$

or

$$DL = 1.1 \times OL + L_{s,max}$$

Where DL is the design load (kW or kVAr)

OL is the operating load (kW or kVAr)

$\sum L_s$ is the sum of all standby loads (kW or kVAr)

$L_{s,max}$ is the largest standby load (kW or kVAr)

The design load includes a margin for any errors in load estimation, load growth or the addition of unforeseen loads that may appear after the design phase. The load schedule is thus more conservative and robust to errors.

On the other hand however, equipment is often over-sized as a result. Sometimes the design load is not calculated and the peak load is used for design purposes.

Worked Example

Step 1: Collect list of loads

Consider a small facility with the following loads identified:

- 2 x 100% vapor recovery compressors (process)
- 2 x 100% recirculation pumps (process)
- 1 x 100% sump pump (process)
- 2 x 50% firewater pumps (safety)
- 1 x 100% HVAC unit (HVAC)
- 1 x 100% AC UPS system (electrical)
- 1 x Normal ligh ng distribu on board (electrical)
- 1 x Essen al ligh ng distribu on board (electrical)

Step 2: Collect electrical load parameters

The following electrical load parameters were collected for the loads identified in Step 1:

Load Description	Abs. Load	Rated Load	PF	Eff.
Vapour recovery compressor A	750kW	800kW	0.87	0.95
Vapour recovery compressor B	750kW	800kW	0.87	0.95
Recirculation pump A	31kW	37kW	0.83	0.86
Recirculation pump B	31kW	37kW	0.83	0.86
Sump pump	9kW	11kW	0.81	0.83
Firewater pump A	65kW	75kW	0.88	0.88
Firewater pump B	65kW	75kW	0.88	0.88
HVAC unit	80kW	90kW	0.85	0.9
AC UPS System	9kW	12kW	0.85	0.9
Normal lighting distribution board	7kW	10kW	0.8	0.9
Essential lighting distribution board	4kW	5kW	0.8	0.9

Step 3: Classify the loads

Suppose we have two voltage levels, 6.6kV and 415V. The loads can be classified as follows:

Load Description	Rated Load	Voltage	Duty	Criticality
Vapour recovery compressor A	800kW	6.6kV	Continuous	Normal
Vapour recovery compressor B	800kW	6.6kV	Standby	Normal
Recirculation pump A	37kW	415V	Continuous	Normal
Recirculation pump B	37kW	415V	Standby	Normal
Sump pump	11kW	415V	Intermittent	Normal
Firewater pump A	75kW	415V	Standby	Essential
Firewater pump B	75kW	415V	Standby	Essential
HVAC unit	90kW	415V	Continuous	Normal
AC UPS System	12kW	415V	Continuous	Critical
Normal lighting distribution board	10kW	415V	Continuous	Normal
Essential lighting distribution board	5kW	415V	Continuous	Essential

Step 4: Calculate consumed load

Calculating the consumed loads for each of the loads in this example gives:

Load Description	Abs Load	PF	Eff.	Continuous		Intermittent		Standby	
				P (kW)	Q (kVAr)	P (kW)	Q (kVAr)	P (kW)	Q (kVAr)
Vapour recovery compressor A	750kW	0.87	0.95	789.5	447.4	-	-	-	-
Vapour recovery compressor B	750kW	0.87	0.95	-	-	-	-	789.5	447.4
Recirculation pump A	31kW	0.83	0.86	36.0	24.2	-	-	-	-
Recirculation pump B	31kW	0.83	0.86	-	-	-	-	36.0	24.2
Sump pump	9kW	0.81	0.83	-	-	10.8	7.9	-	-
Firewater pump A	65kW	0.88	0.88	-	-	-	-	73.9	39.9
Firewater pump B	65kW	0.88	0.88	-	-	-	-	73.9	39.9
HVAC unit	80kW	0.85	0.9	88.9	55.1	-	-	-	-
AC UPS System	9kW	0.85	0.9	10.0	6.2	-	-	-	-
Normal lighting distribution board	7kW	0.8	0.9	7.8	5.8	-	-	-	-

Essential lighting distribution board	4kW	0.8	0.9	4.4	3.3	-	-	-	-
SUM TOTAL				**1,006.6**	**542.0**	**10.8**	**7.9**	**973.3**	**551.4**

Step 5: Calculate operating, peak and design loads

The operating, peak and design loads are calculated as follows:

	P (kW)	Q (kW)
Sum of continuous loads	1,006.6	542.0
50% x Sum of intermi ent load:	5.4	4.0
10% x Sum of standby loads	97.3	55.1
Largest standby load	789.5	447.4
Operating load	1,012.0	546.0
Peak load	1,801.5	993.4
Design load	1,902.7	1,047.9

Normally you would separate the loads by switchboard and calculate operating, peak and design loads for each switchboard and one for the overall system. However for the sake of simplicity, the loads in this example are all lumped together and only one set of operating, peak and design loads are calculated.

Operating Scenarios

It may be necessary to construct load schedules for different operating scenarios. For example, in order to size an emergency diesel generator, it would be necessary to construct a load schedule for emergency scenarios. The classification of the loads by criticality will help in constructing alternative scenarios, especially those that use alternative power sources.

Computer Software

In the past, the load schedule has typically been done manually by hand or with the help of an Excel spreadsheet. However, this type of calculation is extremely well-suited for database driven software packages (such as Smartplant Electrical), especially for very large projects. For smaller projects, it may be far easier to simply perform this calculation manually.

What Next?

The electrical load schedule is the basis for the sizing of most major electrical equipment, from generators to switchgear to transformers. Using the load schedule, major equipment sizing can be started, as well as the power system studies. A preliminary load schedule will also indicate if there will be problems with available power supply / generation, and whether alternative power sources or even process designs will need to be investigated.

Load Profile

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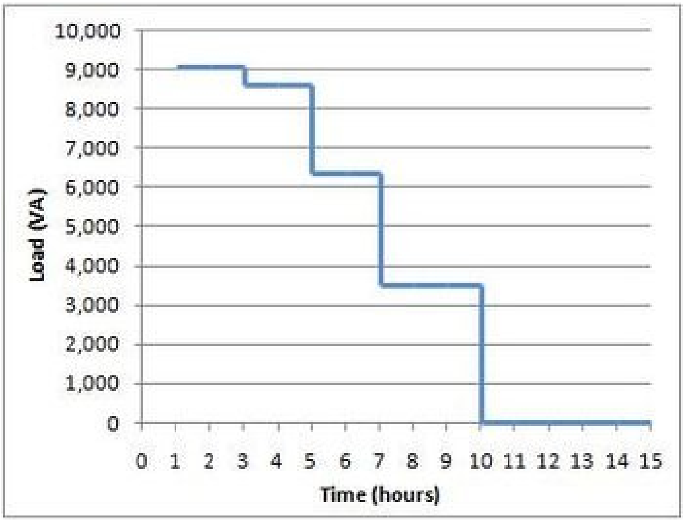
Introduction



Example of a load profile (using the autonomy method)

The energy load profile (hereafter referred to as simply "load profile") is an estimate of the total energy demanded from a power system or sub-system over a specific period of time (e.g. hours, days, etc). The load profile is essentially a two-dimensional chart showing the instantaneous load (in Volt-Amperes) over time, and represents a convenient way to visualize how the system loads changes with respect to time.

Note that it is distinct from the electrical load schedule - the load profile incorporates a time dimension and therefore estimates the energy demand (in kWh) instead of just the instantaneous load / power (in kW).

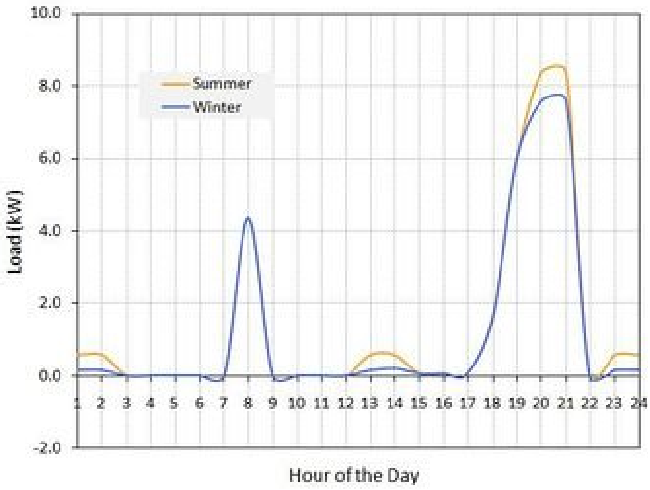
Why do the calculation?

Estimating the energy demand is important for the sizing of energy storage devices, e.g. batteries, as the required capacity of such energy storage devices depends on the total amount of energy that will be drawn by the loads. This calculation is also useful for energy efficiency applications, where it is important to make estimates of the total energy use in a system.

When to do the calculation?

A load profile needs to be constructed whenever the sizing of energy storage devices (e.g. batteries) is required. The calculation can be done once preliminary load information is available.

Calculation Methodology



Example of a load profile (using the 24 hour profile method)

There are two distinct methods for constructing a load profile:

1) **Autonomy** method is the traditional method used for backup power applications, e.g. UPS systems. In this method, the instantaneous loads are displayed over an autonomy time, which is the period of time that the loads need to be supported by a backup power system in the event of a power supply interruption.

2) **24 Hour Profile** method displays the average or expected instantaneous loads over a 24 hour period. This method is more commonly associated with standalone power system applications, e.g. solar systems, or energy efficiency applications.

Both methods share the same three general steps, but with some differences in the details:

- Step 1: Prepare the load list
- Step 2: Construct the load profile
- Step 3: Calculate the design load and design energy demand

Step 1: Prepare the Load List

The first step is to transform the collected loads into a load list. It is similar in form to the electrical load schedule, but is a little simplified for the purpose of constructing a load profile. For instance, instead of categorizing loads by their load duty (continuous, intermittent or standby), it is assumed that all loads are operating continuously.

However, a key difference of this load list is the time period associated with each load item:

In the **autonomy method**, the associated time period is called the "autonomy" and is the number of hours that the load needs to be supported during a power supply interruption. Some loads may only be required to ride through brief interruptions or have enough autonomy to shut down safely, while some critical systems may need to operate for as long as possible (up to several days).

In the **24 hour profile** method, the associated time period is represented in terms of "ON" and "OFF" times. These are the times in the day (in hours and minutes) that the load is expected to be switched on and then later turned off. For loads that operate continuously, the ON and OFF time would be 0:00 and 23:59 respectively. A load item may need to be entered in twice if it is expected to start and stop more than once a day.

Calculating the Consumed Load VA

For this calculation, we are interested in the consumed apparent power of the loads (in VA). For each load, this can be calculated as follows:

$$S_l = \frac{P_l}{\cos\phi \times \eta}$$

Where S_l is the consumed load apparent power (VA)

P_l is the consumed load power (W)

$\cos\phi$ is the load power factor (pu)

η is the load efficiency (pu)

Examples of load lists

Tag Number	Description	Load (W)	Power Factor	Load VA	Autonomy (h)	VA Hours
CCTV-001	CCTV Cabinet	450	0.85	529	3	1,588
DCS-001	DCS System Cabinet	1200	0.85	1,412	5	7,059
DCS-002	DCS System Cabinet	1200	0.85	1,412	5	7,059
ESD-001	ESD System Cabinet	1500	0.85	1,765	8	14,118
EWS-001	Engineering Workstation	400	0.85	471	1	471
FG-001	Fire and Gas Cabinet	1500	0.85	1,765	8	14,118
MON-001	CCTV Camera #1	300	0.80	375	3	1,125
MON-002	CCTV Camera #2	300	0.80	375	3	1,125
MON-003	CCTV Camera #3	300	0.80	375	3	1,125
MON-004	CCTV Camera #4	300	0.80	375	3	1,125
OIS-001	Operator Interface Station #1	100	0.85	118	3	353
OIS-002	Operator Interface Station #2	100	0.85	118	3	353
			TOTAL LOAD VA	9,088	TOTAL VAh	41,618

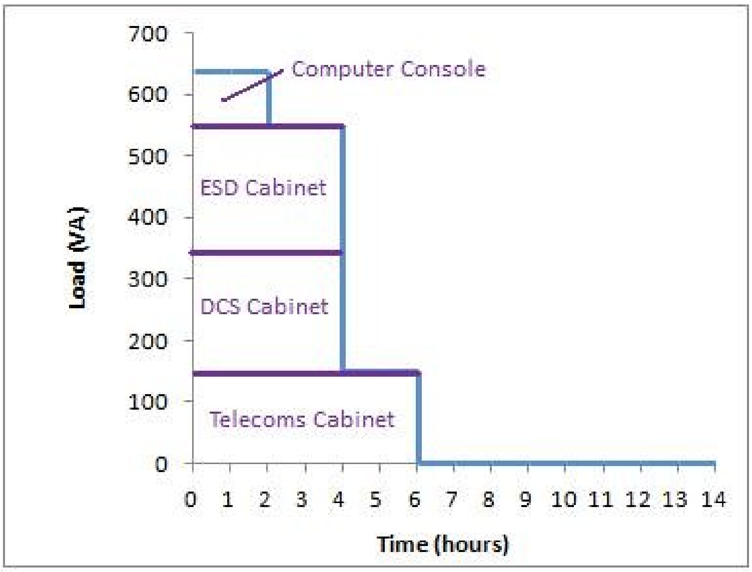
Autonomy method

Tag Number	Description	Load (W)	Power factor	Load VA	Time On	Time Off	VA Hours
TLC-001	Telecommunications Cabinet	50	0.85	59	00:00	23:59	1,411
FB-002	Fibre Optic Panel	35	0.85	41	00:00	23:59	988
LP-001	Lighting - Enclosure	15	0.85	18	20:00	21:00	18
LP-002	Lighting - Security	60	0.85	71	18:00	07:00	776
MON-001	CCTV Camera #1	90	0.80	113	00:00	23:59	2,698
MON-002	CCTV Camera #2	90	0.80	113	00:00	23:59	2,698
MX-001	Multiplexer	20	0.80	25	00:00	23:59	600
			TOTAL LOAD VA	438		TOTAL VAh	8,588

24 hour profile method

Step 2: Construct the Load Profile

The load profile is constructed from the load list and is essentially a chart that shows the distribution of the loads over time. The construction of the load profile will be explained by a simple example:



Load profile constructed for this example

Suppose the following loads were identified based on the Autonomy Method:

Description	Load (VA)	Autonomy (h)
DCS Cabinet	200	4
ESD Cabinet	200	4
Telecommunications Cabinet	150	6
Computer Console	90	2

The load profile is constructed by stacking "energy rectangles" on top of each other. An energy rectangles has the load VA as the height and the autonomy time as the width and its area is a visual representation of the load's total energy. For example, the DCS Cabinet has an energy rectangle of height 200 (VA) and width 4 (hours). The load profile is created by stacking the widest rectangles first, e.g. in this example it is the Telecommunications Cabinet that is stacked first.

For the 24 Hour method, energy rectangles are constructed with the periods of time that a load is energised (i.e. the time difference between the ON and OFF times).

Step 3: Calculate Design Load and Energy Demand

Design Load

The design load is the instantaneous load for which the power conversion, distribution and protection devices should be rated, e.g. rectifiers, inverters, cables, fuses, circuit breakers, etc. The design can be calculated as follows:

$$S_d = S_p(1 + k_g)(1 + k_c)$$

Where S_d is the design load apparent power (VA)

S_p is the peak load apparent power, derived from the load profile (VA)

k_g is a contingency for future load growth (%)

k_c is a design margin (%)

It is common to make considerations for future load growth (typically somewhere between 5 and 20%), to allow future loads to be supported. If no future loads are expected, then this contingency can be ignored. A design margin is used to account for any potential inaccuracies in estimating the loads, less-than-optimum operating conditions due to improper maintenance, etc. Typically, a design margin of 10% to 15% is recommended, but this may also depend on Client preferences.

Example: From our simple example above, the peak load apparent power is 640VA. Given a future growth contingency of 10% and a design margin of 10%, the design load is:

$$S_d = 640 \times (1 + 0.1)(1 + 0.1) = 774.4 \text{ VA}$$

Design Energy Demand

The design energy demand is used for sizing energy storage devices. From the load profile, the total energy (in terms of VAh) can be computed by finding the area underneath the load profile curve (i.e. integrating instantaneous power with respect to time over the autonomy or 24h period). The design energy demand (or design VAh) can then be calculated by the following equation:

$$E_d = E_t(1 + k_g)(1 + k_c)$$

Where E_d is the design energy demand (VAh)

E_t is the total load energy, which is the area under the load profile (VAh)

k_g is a contingency for future load growth as defined above (%)

k_c is a design contingency as defined above (%)

Example: From our simple example above, the total load energy from the load profile is 2,680VAh. Given a future growth contingency of 10% and a design margin of 10%, the design energy demand is:

$$E_d = 2,680 \times (1 + 0.1)(1 + 0.1) = 3,242.8 \text{ VAh}$$

Computer Software

The load profile is normally done manually with the help of a spreadsheet. Since it's such a simple calculation, it's hard to argue that special software is warranted.

What Next?

The load profile is usually an intermediate step in part of a larger calculation (for example, AC UPS System or Solar Power System calculations). Alternatively, constructing a load profile may be the first step to analyzing energy use, for example in energy efficiency applications.

Cable Sizing Calculation

Contents

Introduction

This article examines the sizing of electrical cables (i.e. cross-sectional area) and its implementation in various international standards. Cable sizing methods do differ across international standards (e.g. IEC, NEC, BS, etc) and some standards emphasize certain things over others. However the general principles underlying any cable sizing calculation do not change. In this article, a general methodology for sizing cables is first presented and then the specific international standards are introduced.

Why do the calculation?

The proper sizing of an electrical (load bearing) cable is important to ensure that the cable can:

- Operate continuously under full load without being damaged
- Withstand the worst short circuits currents flowing through the cable
- Provide the load with a suitable voltage (and avoid excessive voltage drops)
- (optional) Ensure operation of protective devices during an earth fault

When to do the calculation?

This calculation can be done individually for each power cable that needs to be sized, or alternatively, it can be used to produce cable sizing waterfall charts for groups of cables with similar characteristics (e.g. cables installed on ladder feeding induction motors).

General Methodology

All cable sizing methods more or less follow the same basic six step process:

1) Gathering data about the cable, its installation conditions, the load that it will carry, etc

2) Determine the minimum cable size based on continuous current carrying capacity

3) Determine the minimum cable size based on voltage drop considerations

4) Determine the minimum cable size based on short circuit temperature rise

5) Determine the minimum cable size based on earth fault loop impedance

6) Select the cable based on the highest of the sizes calculated in step 2, 3, 4 and 5

Step 1: Data Gathering

The first step is to collate the relevant information that is required to perform the sizing calculation. Typically, you will need to obtain the following data:

Load Details

The characteristics of the load that the cable will supply, which includes:

- Load type: motor or feeder
- Three phase, single phase or DC
- System / source voltage
- Full load current (A) - or calculate this if the load is defined in terms of power (kW)
- Full load power factor (pu)
- Locked rotor or load starting current (A)
- Starting power factor (pu)
- Distance / length of cable run from source to load - this length should be as close as possible to the actual route of the cable and include enough contingency for vertical drops / rises and termination of the cable tails

Cable Construction

The basic characteristics of the cable's physical construction, which includes:

- Conductor material - normally copper or Aluminum
- Conductor shape - e.g. circular or shaped
- Conductor type - e.g. stranded or solid
- Conductor surface coating - e.g. plain (no coating), tinned, silver or nickel
- Insulation type - e.g. PVC, XLPE, EPR
- Number of cores - single core or mul core (e.g. 2C, 3C or 4C)

Installation Conditions

How the cable will be installed, which includes:

- Above ground or underground
- Installation / arrangement - e.g. for underground cables, is it directly buried or buried in conduit? for above ground cables, is it installed on cable tray / ladder, against a wall, in air, etc.
- Ambient or soil temperature of the installation site
- Cable bunching, i.e. the number of cables that are bunched together
- Cable spacing, i.e. whether cables are installed touching or spaced
- Soil thermal resistivity (for underground cables)
- Depth of laying (for underground cables)
- For single core three-phase cables, are the cables installed in trefoil or laid flat?

Step 2: Cable Selection Based on Current Rating

Current flowing through a cable generates heat through the resistive losses in the conductors, dielectric losses through the insulation and resistive losses from current flowing through any cable screens / shields and armouring.

The component parts that make up the cable (e.g. conductors, insulation, bedding, sheath, armour, etc) must be capable of withstanding the temperature rise and heat emanating from the cable. The current carrying capacity of a cable is the maximum current that can flow continuously through a cable without damaging the cable's insulation and other components (e.g. bedding, sheath, etc). It is sometimes also referred to as the continuous current rating or ampacity of a cable.

Cables with larger conductor cross-sectional areas (i.e. more copper or Aluminum) have lower resistive losses and are able to dissipate the heat better than smaller cables. Therefore a 16 mm^2 cable will have a higher current carrying capacity than a 4 mm^2 cable.

Base Current Ratings

**Table A.52-10 (52-C9) – Current-carrying capacities in amperes for installation methods E, F and G of table A.52-1 (52-B1) – PVC insulation/Copper conductors
Conductor temperature: 70 °C/Reference ambient temperature: 30 °C**

Nominal cross-sectional area of conductor mm^2	Installation methods of table A.52-1						
	Multi-core cables		Single-core cables				
	Two loaded conductors	Three loaded conductors	Two loaded conductors touching	Three loaded conductors trefoil	Three loaded conductors, flat		
					Touching	Spaced	
						Horizontal	Vertical
	Method E	Method E	Method F	Method F	Method F	Method G	Method G
1	2	3	4	5	6	7	8
1,5	22	18,5	–	–	–	–	–
2,5	30	25	–	–	–	–	–
4	40	34	–	–	–	–	–
6	51	43	–	–	–	–	–
10	70	60	–	–	–	–	–
16	94	80	–	–	–	–	–
25	119	101	131	110	114	146	130
35	148	126	162	137	143	181	162
50	180	153	196	167	174	219	197
70	232	196	251	216	225	281	254
95	282	238	304	264	275	341	311
120	328	276	352	308	321	396	362
150	379	319	406	356	372	456	419
185	434	364	463	409	427	521	480
240	514	430	546	485	507	615	569
300	593	497	629	561	587	709	659
400	–	–	754	656	689	852	795
500	–	–	868	749	789	982	920
630	–	–	1 005	855	905	1 138	1 070

NOTE Circular conductors are assumed for sizes up to and including 16 mm^2. Values for larger sizes relate to shaped conductors and may safely be applied to circular conductors.

Example of base current ra ng table (Excerpt from IEC 603645-52)

International standards and manufacturers of cables will quote base current ratings of different types of cables in tables such as the one shown on the right. Each of these tables pertain to a specific type of cable construction (e.g. copper conductor, PVC insulated, 0.6/1kV voltage grade, etc) and a base set of installation conditions (e.g. ambient temperature, installation method, etc). It is important to note that the current ratings are only valid for the quoted types of cables and base installation conditions.

In the absence of any guidance, the following reference based current ratings may be used.

Installed Current Ratings

When the proposed installation conditions differ from the base conditions, derating (or correction) factors can be applied to the base current ratings to obtain the actual installed current ratings.

International standards and cable manufacturers will provide derating factors for a range of installation conditions, for example ambient / soil temperature, grouping or bunching of cables, soil thermal resistivity, etc. The installed current rating is calculated by multiplying the base current rating with each of the derating factors, i.e.

$$I_c = I_b . k_d$$

where I_c is the installed current rating (A)

I_b is the base current rating (A)

k_d are the product of all the derating factors

For example, suppose a cable had an ambient temperature derating factor of $k_{amb} = 0.94$ and a grouping derating factor of $k_g = 0.85$, then the overall derating factor $k_d = 0.94x0.85 = 0.799$. For a cable with a base current rating of 42A, the installed current rating would be $I_c = 0.799x42 = 33.6A$.

In the absence of any guidance, the following reference derating factors may be used.

Cable Selection and Coordination with Protective Devices

Feeders

When sizing cables for non-motor loads, the upstream protective device (fuse or circuit breaker) is typically selected to also protect the cable against damage from thermal overload. The protective device must therefore be selected to exceed the full load current, but not exceed the cable's installed current rating, i.e. this inequality must be met:

$$I_l \leq I_p \leq I_c$$

Where I_l is the full load current (A)

I_p is the protective device rating (A)

I_c is the installed cable current rating (A)

Motors

Motors are normally protected by a separate thermal overload (TOL) relay and therefore the upstream protective device (e.g. fuse or circuit breaker) is not required to protect the cable against overloads. As a result, cables need only to be sized to cater for the full load current of the motor, i.e.

$$I_l \leq I_c$$

Where I_l is the full load current (A)

I_c is the installed cable current rating (A)

Of course, if there is no separate thermal overload protection on the motor, then the protective device needs to be taken into account as per the case for feeders above.

Step 3: Voltage Drop

A cable's conductor can be seen as an impedance and therefore whenever current flows through a cable, there will be a voltage drop across it, which can be derived by Ohm's Law (i.e. V = IZ). The voltage drop will depend on two things:

- Current flow through the cable – the higher the current flow, the higher the voltage drop
- Impedance of the conductor – the larger the impedance, the higher the voltage drop

Cable Impedances

The impedance of the cable is a function of the cable size (cross-sectional area) and the length of the cable. Most cable manufacturers will quote a cable's resistance and reactance in Ω/km. The following typical cable impedances for low voltage AC and DC single core and multicore cables can be used in the absence of any other data.

Calculating Voltage Drop

For AC systems, the method of calculating voltage drops based on load power factor is commonly used. Full load currents are normally used, but if the load has high startup currents (e.g. motors), then voltage drops based on starting current (and power factor if applicable) should also be calculated.

For a three phase system:

$$V_{3\phi} = \frac{\sqrt{3}I(R_c \cos\phi + X_c \sin\phi)L}{1000}$$

Where $V_{3\phi}$ is the three phase voltage drop (V)

I is the nominal full load or starting current as applicable (A)

R_c is the ac resistance of the cable (Ω/km)

X_c is the ac reactance of the cable (Ω/km)

$\cos\phi$ is the load power factor (pu)

L is the length of the cable (m)

For a single phase system:

$$V_{1\phi} = \frac{2I(R_c \cos\phi + X_c \sin\phi)L}{1000}$$

Where $V_{1\phi}$ is the single phase voltage drop (V)

I is the nominal full load or starting current as applicable (A)

R_c is the ac resistance of the cable (Ω/km)

X_c is the ac reactance of the cable (Ω/km)

$\cos\phi$ is the load power factor (pu)

L is the length of the cable (m)

For a DC system:

$$V_{dc} = \frac{2IR_cL}{1000}$$

Where V_{dc} is the dc voltage drop (V)

I is the nominal full load or starting current as applicable (A)

R_c is the dc resistance of the cable (Ω/km)

L is the length of the cable (m)

Maximum Permissible Voltage Drop

It is customary for standards (or clients) to specify maximum permissible voltage drops, which is the highest voltage drop that is allowed across a cable. Should your cable exceed this voltage drop, then a larger cable size should be selected.

Maximum voltage drops across a cable are specified because load consumers (e.g. appliances) will have an input voltage tolerance range. This means that if the voltage at the appliance is lower than its rated minimum voltage, then the appliance may not operate correctly.

In general, most electrical equipment will operate normally at a voltage as low as 80% nominal voltage. For example, if the nominal voltage is 230VAC, then most appliances will run at >184VAC. Cables are typically sized for a more conservative maximum voltage drop, in the range of 5 – 10% at full load.

Calculating Maximum Cable Length due to Voltage Drop

It may be more convenient to calculate the maximum length of a cable for a particular conductor size given a maximum permissible voltage drop (e.g. 5% of nominal voltage at full load) rather than the voltage drop itself. For example, by doing this it is possible to construct tables showing the maximum lengths corresponding to different cable sizes in order to speed up the selection of similar type cables.

The maximum cable length that will achieve this can be calculated by re-arranging the voltage drop equations and substituting the maximum permissible voltage drop (e.g. 5% of 415V nominal voltage = 20.75V). For a three phase system:

$$L_{max} = \frac{1000V_{3\phi}}{\sqrt{3}I(R_c \cos\phi + X_c \sin\phi)}$$

Where L_{max} is the maximum length of the cable (m)

$V_{3\phi}$ is the maximum permissible three phase voltage drop (V)

I is the nominal full load or starting current as applicable (A)

R_c is the ac resistance of the cable (Ω/km)

X_c is the ac reactance of the cable (Ω/km)

$\cos\phi$ is the load power factor (pu)

For a single phase system:

$$L_{max} = \frac{1000V_{1\phi}}{2I(R_c \cos\phi + X_c \sin\phi)}$$

Where L_{max} is the maximum length of the cable (m)

$V_{1\phi}$ is the maximum permissible single phase voltage drop (V)

I is the nominal full load or starting current as applicable (A)

R_c is the ac resistance of the cable (Ω/km)

X_c is the ac reactance of the cable (Ω/km)

$\cos\phi$ is the load power factor (pu)

For a DC system:

$$L_{max} = \frac{1000V_{dc}}{2IR_c}$$

Where L_{max} is the maximum length of the cable (m)

V_{dc} is the maximum permissible dc voltage drop (V)

I is the nominal full load or starting current as applicable (A)

R_c is the dc resistance of the cable (Ω/km)

L is the length of the cable (m)

Step 4: Short Circuit Temperature Rise

During a short circuit, a high amount of current can flow through a cable for a short time. This surge in current flow causes a temperature rise within the cable. High temperatures can trigger unwanted reactions in the cable insulation, sheath materials and other components, which can prematurely degrade the condition of the cable. As the cross-sectional area of the cable increases, it can dissipate higher fault currents for a given temperature rise. Therefore, cables should be sized to withstand the largest short circuit that it is expected to see.

Minimum Cable Size Due to Short Circuit Temperature Rise

The minimum cable size due to short circuit temperature rise is typically calculated with an equation of the form:

$$A = \frac{\sqrt{i^2 t}}{k}$$

Where A is the minimum cross-sectional area of the cable (mm^2)

i is the prospective short circuit current (A)

t is the duration of the short circuit (s)

k is a short circuit temperature rise constant

The temperature rise constant is calculated based on the material properties of the conductor and the initial and final conductor temperatures (see the derivation here). Different international standards have different treatments of the temperature rise constant, but by way of example, IEC 60364-5-54 calculates it as follows:

$$k = 226\sqrt{\ln\left(1 + \frac{\theta_f - \theta_i}{234.5 + \theta_i}\right)}$$ (for copper conductors)

$$k = 148\sqrt{\ln\left(1 + \frac{\theta_f - \theta i}{228 + \theta_i}\right)}$$ (for Aluminum conductors)

Where θ_i is the initial conductor temperature (deg C)

θ_i is the final conductor temperature (deg C)

Initial and Final Conductor Temperatures

The initial conductor temperature is typically chosen to be the maximum operating temperature of the cable. The final conductor temperature is typically chosen to be the limiting temperature of the insulation. In general, the cable's insulation will determine the maximum operating temperature and limiting temperatures.

As a rough guide, the following temperatures are common for the different insulation materials:

Material	Max Operating Temperature °C	Limiting Temperature °C
PVC	75	160
EPR	90	250
XLPE	90	250

Short Circuit Energy

The short circuit energy i^2t is normally chosen as the maximum short circuit that the cable could potentially experience. However for circuits with current limiting devices (such as HRC fuses), then the short circuit energy chosen should be the maximum prospective let-through energy of the protective device, which can be found from manufacturer data.

Step 5: Earth Fault Loop Impedance

Sometimes it is desirable (or necessary) to consider the earth fault loop impedance of a circuit in the sizing of a cable. Suppose a bolted earth fault occurs between an active conductor and earth. During such an earth fault, it is desirable that the upstream protective device acts to interrupt the fault within a maximum disconnection time so as to protect against any inadvertent contact to exposed live parts.

Ideally the circuit will have earth fault protection, in which case the protection will be fast acting and well within the maximum disconnection time. The maximum disconnection time is chosen so that a dangerous touch voltage does not persist for long enough to cause injury or death. For most circuits, a maximum disconnection time of 5s is sufficient, though for portable equipment and socket outlets, a faster disconnection time is desirable (i.e. <1s and will definitely require earth fault protection).

However for circuits that do not have earth fault protection, the upstream protective device (i.e. fuse or circuit breaker) must trip within the maximum disconnection time. In order for the protective device to trip, the fault current due to a bolted short circuit must exceed the value that will cause the protective device to act within the maximum disconnection time. For example, suppose a circuit is protected by a fuse and the maximum disconnection time is 5s, then the fault current must exceed the fuse melting current at 5s (which can be found by cross-referencing the fuse time-current curves).

By simple application of Ohm's law:

$$I_A = \frac{V_0}{Z_s}$$

Where I_A is the earth fault is current required to trip the protective device within the minimum disconnection time (A)

V_0 is the phase to earth voltage at the protective device (V)

Z_s is the impedance of the earth fault loop (Ω)

It can be seen from the equation above that the impedance of the earth fault loop must be sufficiently low to ensure that the earth fault current can trip the upstream protection.

The Earth Fault Loop

The earth fault loop can consist of various return paths other than the earth conductor, including the cable armour and the static earthing connection of the facility. However for practical reasons, the earth fault loop in this calculation consists only of the active conductor and the earth conductor.

The earth fault loop impedance can be found by:

$$Z_s = Z_c + Z_e$$

Where Z_s is the earth fault loop impedance (Ω)

Z_c is the impedance of the active conductor (Ω)

Z_e is the impedance of the earth conductor (Ω)

Assuming that the active and earth conductors have identical lengths, the earth fault loop impedance can be calculated as follows:

$$Z_s = \frac{L}{1000}\sqrt{(R_c + R_e)^2 + (X_c + X_e)^2}$$

Where L is the length of the cable (m)

R_c and R_e are the ac resistances of the active and earth conductors respectively (Ω/km)

X_c and X_e are the reactances of the active and earth conductors respectively (Ω/km)

Maximum Cable Length

The maximum earth fault loop impedance can be found by re-arranging the equation above:

$$Z_{s,max} = \frac{V_0}{I_A}$$

Where Z_s is the maximum earth fault loop impedance (Ω)

V_0 is the phase to earth voltage at the protective device (V)

I_A is the earth fault current required to trip the protective device within the minimum disconnection time (A)

The maximum cable length can therefore be calculated by the following:

$$L_{max} = \frac{1000V_0}{I_A\sqrt{(R_c + R_e)^2 + (X_c + X_e)^2}}$$

Where L_{max} is the maximum cable length (m)

V_0 is the phase to earth voltage at the protective device (V)

I_A is the earth fault current required to trip the protective device within the minimum disconnection time (A)

R_c and R_e are the ac resistances of the active and earth conductors respectively (Ω/km)

X_c and X_e are the reactances of the active and earth conductors respectively (Ω/km)

Note that the voltage V_0 at the protective device is not necessarily the nominal phase to earth voltage, but usually a lower value as it can be downstream of the main busbars. This voltage is commonly represented by applying some factor c to the nominal voltage. A conservative value of c = 0.8 can be used so that:

$$V_0 = cV_n = 0.8V_n$$

Where V_n is the nominal phase to earth voltage (V)

Worked Example

In this example, we will size a cable for a 415V, 30kW three-phase motor from the MCC to the field.

Step 1: Data Gathering

The following data was collected for the cable to be sized:

- Cable type: Cu/PVC/GSWB/PVC, 3C+E, 0.6/1kV
- Opera ng temperature: 75(
- Cable installation: above ground on cable ladder bunched together with 3 other cables on a single layer and at 30C ambient temperature
- Cable run: 90m (including tails)
- Motor load: 30kW, 415V three phase, full load current = 58A, power factor = 0.87
- Protection: a fuse of ra ng = 80A, max prospec e fault I^2t = 90 A^2s , 5s melt me = 550/

Step 2: Cable Selection Based on Current Rating

Suppose the ambient temperature derating is 0.89 and the grouping derating for 3 bunched cables on a single layer is 0.82. The overall derating factor is 0.89 $\times$ 0.82 = 0.7298. Given that a 25 mm^2 and 35 mm^2 have base current ratings of 78A and 96A respectively, which cable should be selected based on current rating considerations?

The installed current ratings for 25 mm^2 and 35 mm^2 is 0.7298 $\times$ 78A = 56.92A and 0.7298 $\times$ 96A = 70.06A respectively. Given that the full load current of the motor is 58A, then the installed current rating of the 25 mm^2 cable is lower than the full load current and is not suitable for continuous use with the motor. The 35 mm^2 cable on the other hand has an installed current rating that exceeds the motor full load current, and is therefore the cable that should be selected.

Step 3: Voltage Drop

Suppose a 35 mm^2 cable is selected. If the maximum permissible voltage drop is 5%, is the cable suitable for a run length of 90m?

A 35 mm^2 cable has an ac resistance of 0.638 Ω/km and a reactance of 0.0826 Ω/km. The voltage drop across the cable is:

$$V_d = \frac{90}{1000} \times \sqrt{3} \times 59 \times \left[0.638 \times 0.85 + 0.0826 \times \sin(\cos^{-1}(0.85)\right] = 5.388V$$

A voltage drop of 5.388V is equivalent to $\frac{5.388}{415} = 1.298\%$, which is lower than the maximum permissible voltage drop of 5%. Therefore the cable is suitable for the motor based on voltage drop considerations.

Step 4: Short Circuit Temperature Rise

The cable is operating normally at 75C and has a prospective fault capacity (I^2t) of 90 A^2s. What is the minimum size of the cable based on short circuit temperature rise?

XLPE has a limiting temperature of 160C. Using the IEC formula, the short circuit temperature rise constant is 111.329. The minimum cable size due to short circuit temperature rise is therefore:

$$A = \frac{\sqrt{90,000}}{111.329} = 28.43mm^2$$

Therefore, our 35 mm^2 cable is still suitable for this application.

Step 5: Earth Fault Loop Impedance

Suppose there is no special earth fault protection for the motor and a bolted single phase to earth fault occurs at the motor terminals. The earth conductor for our 35 mm^2 cable is 10 mm^2. If the maximum disconnection time is 5s, is our 90m long cable suitable based on earth fault loop impedance?

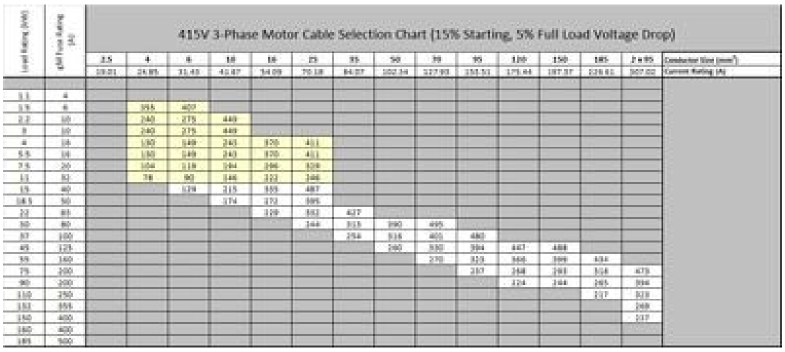
The 80A motor fuse has a 5s melting current of 550A. The ac resistances of the active and earth conductors are 0.638 Ω/km and 2.33 Ω/km) respectively. The reactances of the active and earth conductors are 0.0826 Ω/km and 0.0967 Ω/km) respectively.

The maximum length of the cable allowed is calculated as:

$$L_{max} = \frac{(1000)(0.8)(240)}{550\sqrt{(0.638 + 2.33)^2 + (0.0826 + 0.0967)^2}} = 117m$$

The cable run is 90m and the maximum length allowed is 117m, therefore our cable is suitable based on earth fault loop impedance. In fact, our 35 mm^2 cable has passed all the tests and is the size that should be selected.

Waterfall Charts



Example of a cable waterfall chart

Sometimes it is convenient to group together similar types of cables (for example, 415V PVC motor cables installed on cable ladder) so that instead of having to go through the laborious exercise of sizing each cable separately, one can select a cable from a pre-calculated chart.

These charts are often called "waterfall charts" and typically show a list of load ratings and the maximum of length of cable permissible for each cable size. Where a particular cable size fails to meet the requirements for current carrying capacity or short circuit temperature rise, it is blacked out on the chart (i.e. meaning that you can't choose it).

Preparing a waterfall chart is common practice when having to size many like cables and substantially cuts down the time required for cable selection.

International Standards

IEC

IEC 60364-5-52 (2009) "Electrical installations in buildings - Part 5-52: Selection and erection of electrical equipment - Wiring systems" is the IEC standard governing cable sizing.

NEC

NFPA 70 (2011) "National Electricity Code" is the equivalent standard for IEC 60364 in North America and includes a section covering cable sizing in Article 300.

BS

BS 7671 (2008) "Requirements for Electrical Installations - IEE Wiring Regulations" is the equivalent standard for IEC 60364 in the United Kingdom.

AS/NZS

AS/NZS 3008.1 (2009) "Electrical installations - Selection of cables - Cables for alternating voltages up to and including 0.6/1 kV" is the standard governing low voltage cable sizing in Australia and New Zealand. AS/NZS 3008.1.1 is for Australian conditions and AS/NZS 3008.1.2 is for New Zealand conditions.

Computer Software

Cablesizer is a free online application for sizing cables to IEC standards.

Most of the major electrical analysis packages (e.g. ETAP, PTW, etc) have a cable sizing module. There also exist other (offline) software packages that include cable sizing (for example from Solutions Electrical UK).

What next?

Having sized the power / load-bearing cables, the cable schedule can now be developed and then the cable material take-offs (MTO).

Motor Starting

Contents

Introduction

High voltage motor (courtesy of ABB)

This article considers the transient effects of motor starting on the system voltage. Usually only the largest motor on a bus or system is modeled, but the calculation can in principle be used for any motor. It's important to note that motor starting is a transient power flow problem and is normally done iteratively by computer software. However a static method is shown here for first-pass estimates only.

Why do the calculation?

When a motor is started, it typically draws a current 6-7 times its full load current for a short duration (commonly called the locked rotor current). During this transient period, the source impedance is generally assumed to be fixed and therefore, a large increase in current will result in a larger voltage drop across the source impedance. This means that there can be large momentary voltage drops system-wide, from the power source (e.g. transformer or generator) through the intermediary buses, all the way to the motor terminals.

A system-wide voltage drop can have a number of adverse effects, for example:

- Equipment with minimum voltage tolerances (e.g. electronics) may malfunction or behave aberrantly
- Under voltage protection may be tripped
- The motor itself may not start as torque is proportional to the square of the stator voltage, so a reduced voltage equals lower torque. Induction motors are typically designed to start with a terminal voltage >80%

When to do the calculation?

This calculation is more or less done to verify that the largest motor does not cause system wide problems upon starting. Therefore it should be done after preliminary system design is complete. The following prerequisite information is required:

- Key single line diagrams
- Preliminary load schedule
- Tolerable voltage drop limits during motor starting, which are typically prescribed by the client

Calculation Methodology

This calculation is based on standard impedance formulae and Ohm's law. To the author's knowledge, there are no international standards that govern voltage drop calculations during motor start.

It should be noted that the proposed method is not 100% accurate because it is a static calculation. In reality, the voltage levels are fluctuating during a transient condition, and therefore so are the load currents drawn by the standing loads. This makes it essentially a load flow problem and a more precise solution would solve the load flow problem iteratively, for example using the Newton-Rhapson or Gauss-Siedel algorithms. Notwithstanding, the proposed method is suitably accurate for a first pass solution.

The calculation has the following six general steps:

- Step 1: Construct the system model and assemble the relevant equipment parameters
- Step 2: Calculate the relevant impedances for each equipment item in the model
- Step 3: Refer all impedances to a reference voltage
- Step 4: Construct the equivalent circuit for the voltage levels of interest
- Step 5: Calculate the ini al steady-state source emf before motor starting
- Step 6: Calculate the system voltages during motor start

Step 1: Construct System Model and Collect Equipment Parameters

The first step is to construct a simplified model of the system single line diagram, and then collect the relevant equipment parameters. The model of the single line diagram need only show the buses of interest in the motor starting calculation, e.g. the upstream source bus, the motor bus and possibly any intermediate or downstream buses that may be affected. All running loads are shown as lumped loads except for the motor to be started as it is assumed that the system is in a steady-state before motor start.

The relevant equipment parameters to be collected are as follows:

- Network feeders: fault capacity of the network (VA), X/R ratio of the network
- Generators: per-unit transient reactance, rated generator capacity (VA)
- Transformers: transformer impedance voltage (%), rated transformer capacity (VA), rated current (A), total copper loss (W)
- Cables: length of cable (m), resistance and reactance of cable ($\Omega\ km$)
- Standing loads: rated load capacity (VA), average load power factor (pu)
- Motor: full load current (A), locked rotor current (A), rated power (W), full load power factor (pu), starting power factor (pu)

Step 2: Calculate Equipment Impedances

Using the collected parameters, each of the equipment item impedances can be calculated for later use in the motor starting calculations.

Network Feeders

Given the approximate fault level of the network feeder at the connection point (or point of common coupling), the impedance, resistance and reactance of the network feeder is calculated as follows:

$$Z_f = \frac{cV_n^2}{S_f}$$

$$R_f = \frac{Z_f}{\sqrt{1 + \left(\frac{X}{R}\right)^2}}$$

$$X_f = \frac{X}{R} \times R_f$$

Where Z_f is impedance of the network feeder (Ω)

R_f is resistance of the network feeder (Ω)

X_f is reactance of the network feeder (Ω)

V_n is the nominal voltage at the connection point (Vac)

S_f is the fault level of the network feeder (VA)

c is a voltage factor which accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

$\frac{X}{R}$ is X/R ratio of the network feeder (pu)

Synchronous Generators

The transient resistance and reactance of a synchronous generator can be estimated by the following:

$$X_d' = \chi_d' \times K_g \times \frac{V_g^2}{S_g}$$

$$R_g = \frac{X_d'}{\frac{X}{R}}$$

$$K_g = \frac{V_n}{V_g} \frac{c}{1 + \chi_d' \sin\phi_g}$$

Where X_d' is the transient reactance of the generator (Ω)

R_g is the resistance of the generator (Ω)

K_g is a voltage correction factor (pu)

X_d' is the per-unit transient reactance of the generator (pu)

V_g is the nominal generator voltage (Vac)

V_n is the nominal system voltage (Vac)

S_g is the rated generator capacity (VA)

$\frac{X}{R}$ is the X/R ra o, typically 20 for $S_g \geq$ 100MVA, 14.29 for $S_g <$ 100MVA, and 6.67 for all generators with nominal voltage $V_g \leq$ 1kV

c is a voltage factor which accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

$\cos \phi_g$ is the power factor of the generator (pu)

Transformers

The impedance, resistance and reactance of two-winding transformers can be calculated as follows:

$$Z_t = u_k \frac{V_t^2}{S_t}$$

$$R_t = \frac{P_{kt}}{3I_t^2}$$

$$X_t = \sqrt{Z_t^2 - R_t^2}$$

Where Z_t is the impedance of the transformer (Ω)

R_t is the resistance of the transformer (Ω)

X_t is the reactance of the transformer (Ω)

u_k is the impedance voltage of the transformer (pu)

S_t is the rated capacity of the transformer (VA)

V_t is the nominal voltage of the transformer at the high or low voltage side (Vac)

I_t is the rated current of the transformer at the high or low voltage side (I)

P_{kt} is the total copper loss in the transformer windings (W)

Cables

Cable impedances are usually quoted by manufacturers in terms of Ohms per km. These need to be converted to Ohms based on the length of the cables:

$$R_c = R \times \frac{L_c}{1000}$$

$$X_c = X \times \frac{L_c}{1000}$$

Where R_c is the resistance of the cable {Ω)

X_c is the reactance of the cable {Ω)

R is the quoted resistance of the cable {Ω / *km*)

X is the quoted reactance of the cable {Ω / *km*)

L_c is the length of the cable {m)

Standing Loads

Standing loads are lumped loads comprising all loads that are operating on a particular bus, excluding the motor to be started. Standing loads for each bus need to be calculated.

The impedance, resistance and reactance of the standing load is calculated by:

$$Z_l = \frac{V_l^2}{S_l}$$

$$R_l = Z_l \cos \phi$$

$$X_l = \sqrt{Z_l^2 - R_l^2}$$

Where Z_l is the impedance of the standing load {Ω)

R_l is the resistance of the standing load {Ω)

X_l is the reactance of the standing load {Ω)

V_l is the standing load nominal voltage (Vac)

S_l is the standing load apparent power (VA)

$\cos\phi$ is the average load power factor (pu)

Motors

The motor's transient impedance, resistance and reactance is calculated as follows:

$$Z_m = \frac{1}{I_{LRC}/I_{FLC}} \times \frac{V_m^2 \cos\phi_m}{P_m}$$

$$R_m = \frac{P_m \times I_{LRC}/I_{FLC} \times \cos\phi_s}{3I_{LRC}^2 \times \cos\phi_m}$$

$$X_m = \sqrt{Z_m^2 - R_m^2}$$

Where Z_m is transient impedance of the motor (Ω)

R_m is transient resistance of the motor (Ω)

X_m is transient reactance of the motor (Ω)

I_{LRC}/I_{FLC} is ratio of the locked rotor to full load current

I_{LRC} is the motor locked rotor current (A)

V_m is the motor nominal voltage (Vac)

P_m is the motor rated power (W)

$\cos\phi_m$ is the motor full load power factor (pu)

$\cos\phi_s$ is the motor starting power factor (pu)

Step 3: Referring Impedances

Where there are multiple voltage levels, the equipment impedances calculated earlier need to be converted to a reference voltage (typically the HV side) in order for them to be used in a single equivalent circuit.

The winding ratio of a transformer can be calculated as follows:

$$n = \frac{V_{t2}(1 + t_p)}{V_{t1}}$$

Where n is the transformer winding ratio

V_{t2} is the transformer nominal secondary voltage at the principal tap (Vac)

V_{t1} is the transformer nominal primary voltage (Vac)

t_p is the specified tap setting (%)

Using the winding ratio, impedances (as well as resistances and reactances) can be referred to the primary (HV) side of the transformer by the following relation:

$$Z_{HV} = \frac{Z_{LV}}{n^2}$$

Where Z_{HV} is the impedance referred to the primary (HV) side (Ω)

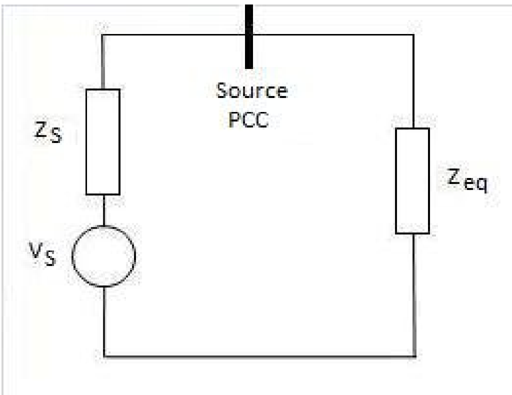
Z_{LV} is the impedance at the secondary (LV) side (Ω)

n is the transformer winding ratio (pu)

Conversely, by re-arranging the equation above, impedances can be referred to the LV side:

$$Z_{LV} = Z_{HV} \times n^2$$

Step 4: Construct the Equivalent Circuit



"Near" Thévenin equivalent circuit

The equivalent circuit essentially consists of a voltage source (from a network feeder or generator) plus a set of complex impedances representing the power system equipment and load impedances.

The next step is to simplify the circuit into a form that is nearly the Thévenin equivalent circuit, with a circuit containing only a voltage source (V_s), source impedance (Z_s) and equivalent load impedance (Z_{eq}).

This can be done using the standard formulae for series and parallel impedances, keeping in mind that the rules of complex arithmetic must be used throughout. This simplification to a "Near" Thévenin equivalent circuit should be done both with the motor off (open circuit) and the motor in a starting condition.

Step 5: Calculate the Initial Source EMF

Assuming that the system is initially in a steady-state condition, we need to first calculate the initial e.m.f produced by the power source (i.e. feeder connection point or generator terminals). This voltage will be used in the transient calculations (Step 6) as the initial source voltage.

Assumptions regarding the steady-state condition:

- The source point of common coupling (PCC) is at its nominal voltage
- The motor is switched off
- All standing loads are opera ng at the capacity calculated in Step 2
- All transformer taps are set at those specified in Step 2
- The system is at a steady-state, i.e. there is no switching taking place throughout the system

Since we assume that there is nominal voltage at the PCC, the initial source e.m.f can be calculated by voltage divider:

$$E_0 = V_n \left(1 + \frac{Z_s}{Z_{eq}}\right)$$

Where E_0 is the initial e.m.f of the power source (Vac)

V_n is the nominal voltage (Vac)

Z_s is the source impedance (Ω)

Z_{eq} is the equivalent load impedance with the motor switched off (Ω)

Step 6: Calculate System Voltages During Motor Start

It is assumed in this calculation that during motor starting, the initial source e.m.f calculated in Step 5 remains constant; that is, the power source does not react during the transient period. This is a simplifying assumption in order to avoid having to model the transient behavior of the power source.

Next, we need to calculate the overall system current that is supplied by the power source during the motor starting period. To do this, we use the "Near" Thévenin equivalent circuit derived earlier, but now include the motor starting impedance. A new equivalent load impedance during motor starting $Z_{eq.s}$ will be calculated.

The current supplied by the power source is therefore:

$$I_s = \frac{E_0}{Z_{eq.s} + Z_s}$$

Where I_s is the system current supplied by the source (A)

E_0 is the initial source e.m.f (Vac)

$Z_{eq.s}$ is the equivalent load impedance during motor start (Ω)

Z_s is the source impedance (Ω)

The voltage at the source point of common coupling (PCC) is:

$$V_{PCC} = E_0 - I_s Z_s$$

Where V_{PCC} is the voltage at the point of common coupling (Vac)

E_0 is the initial source e.m.f (Vac)

I_s is the system current supplied by the source (A)

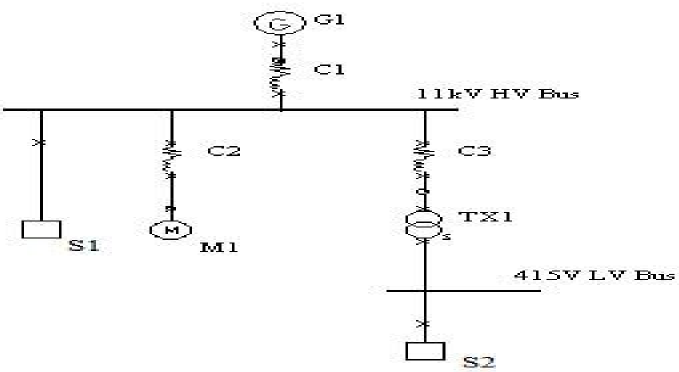
Z_s is the source impedance (Ω)

The downstream voltages can now be calculated by voltage division and simple application of Ohm's law. Specifically, we'd like to know the voltage at the motor terminals and any buses of interest that could be affected. Ensure that the voltages are acceptably within the prescribed limits, otherwise further action needs to be taken (refer to what’s Next? section).

Worked Example

The worked example here is a very simple power system with two voltage levels and supplied by a single generator. While unrealistic, it does manage to demonstrate the key concepts pertaining to motor starting calculations.

Step 1: Construct System Model and Collect Equipment Parameters



Simplified system model for motor starting example

The power system has two voltage levels, 11kV and 415V, and is fed via a single 4MVA generator (G1). The 11kV bus has a standing load of 950kVA (S1) and we want to model the effects of starting a 250kW motor (M1). There is a standing load of 600kVA at 415V (S2), supplied by a 1.6MVA transformer (TX1). The equipment and cable parameters are as follows:

Equipment	Parameters
Generator G1	• S_{g1} = 4,000 kVA • V_{g1} = 11,000 V • X_d' = 0.33 pu • $\cos\phi$ = 0.85 pu
Generator Cable C1	• Length = 50m • Size = 500 mm^2 (R = 0.0522 Ω\km, X = 0.0826 Ω\km)
11kV Standing Load S1	• S_{s1} = 950 kVA • V_{s1} = 11,000 V • $\cos\phi$ = 0.84 pu
Motor M1	• P_{m1} = 250 kW • V_{m1} = 11,000 V • I_{LRC} = 106.7 A • I_{LRC}/I_{FLC} = 6.5 pu • $\cos\phi_m$ = 0.85 pu • $\cos\phi_s$ = 0.30 pu
Motor Cable C2	• Length = 150m • Size = 35 mm^2 (R = 0.668 Ω\km, X = 0.115 Ω\km)
Transformer TX1	• S_{tx1} = 1,600 kVA • V_{t1} = 11,000 V • V_{t2} = 415 V • u_k = 0.06 pu • P_{kt} = 12,700 W • t_p = 0%
Transformer Cable C3	• Length = 60m • Size = 120 mm^2 (R = 0.196 Ω\km, X = 0.096 Ω\km)
415V Standing Load S2	• S_{s2} = 600 kVA • V_{s2} = 415 V • $\cos\phi$ = 0.80 pu

Step 2: Calculate Equipment Impedances

Using the parameters above and the equations outlined earlier in the methodology, the following impedances were calculated:

Equipment	Resistance (Ω)	Reactance (Ω)
Generator G1	0.65462	9.35457
Generator Cable C1	0.00261	0.00413
11kV Standing Load S1	106.98947	69.10837
Motor M1	16.77752	61.02812
Motor Cable C2	0.1002	0.01725
Transformer TX1 (Primary Side)	0.60027	4.49762
Transformer Cable C3	0.01176	0.00576
415V Standing Load S2	0.22963	0.17223

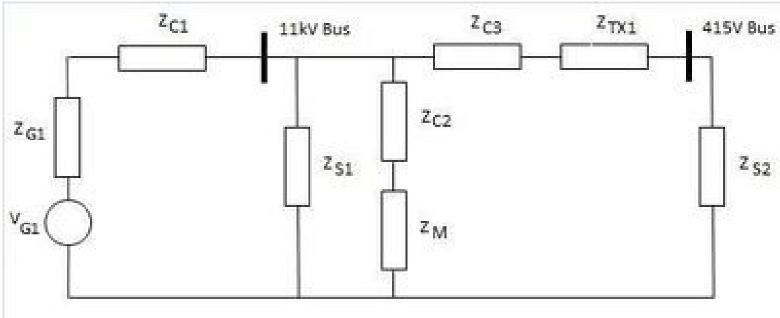
Step 3: Referring Impedances

11kV will be used as the reference voltage. The only impedance that needs to be referred to this reference voltage is the 415V Standing Load (S2). Knowing that the transformer is set at principal tap, we can calculate the winding ratio and apply it to refer the 415V Standing Load impedance to the 11kV side:

$$n = \frac{415\,(1 + 0\%)}{11,000} = 0.03773$$

The resistance and reactance of the standing load referred to the 11kV side is now, R = 161.33333 Ω and X = 121.00 Ω.

Step 4: Construct the Equivalent Circuit



Equivalent circuit for motor starting example

The equivalent circuit for the system is shown in the figure to the right. The "Near" Thévenin equivalent circuit is also shown, and we now calculate the equivalent load impedance Z_{eq} in the steady-state condition (i.e. without the motor and motor cable impedances included):

$$Z_{eq} = Z_{C1} + [Z_{S1} || (Z_{C3} + Z_{TX1} + Z_{S2})]$$

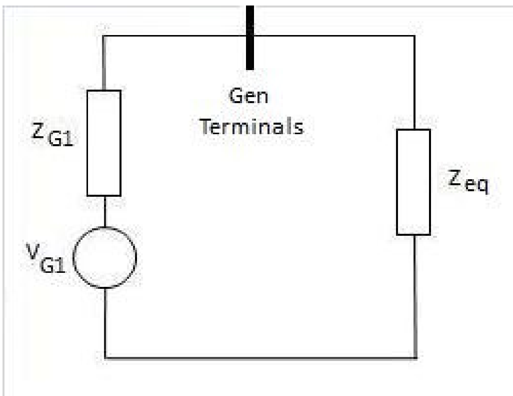
$$= 64.59747 + j44.80458$$

Similarly the equivalent load impedance during motor starting (with the motor impedances included) can be calculated as as follows:

$$Z_{eq.s} = Z_{C1} + [Z_{S1} || (Z_{C3} + Z_{TX1} + Z_{S2}) || Z_{C2} + Z_{M1}]$$

$$= 20.371997 + j31.22116$$

Step 5: Calculate the Initial Source EMF



"Near" Thévenin equivalent circuit for motor starting example

Assuming that there is nominal voltage at the 11kV bus in the steady-state condition, the initial generator e.m.f can be calculated by voltage divider:

$$E_0 = V_n \left(1 + \frac{Z_{G1}}{Z_{eq}}\right)$$

$$= 11,821.25 + j1,023.33 = 11,865$$ Vac

Step 6: Calculate System Voltages During Motor Start

Now we can calculate the transient effects of motor starting on the system voltages. Firstly, the current supplied by the generator during motor start is calculated:

$$I_{G1} = \frac{E_0}{Z_{eq,s} + Z_{G1}}$$

$$= 138.8949 - j219.36166 = 259.64A$$

Next, the voltage at the 11kV bus can be found:

$$V_{11kV} = E_0 - I_{G1}(Z_{G1} + Z_{C1})$$

$$= 9,677.024 - j132.375 = 9,677.9$$ Vac (or 87.98% of nominal voltage)

The voltage at the motor terminals can then be found by voltage divider:

$$V_{M1} = V_{11kV} \frac{Z_{M1}}{Z_{C2} + Z_{M1}}$$

$$= 9,670.597 - j118.231 = 9,671.3$$ Vac (or 87.92% of nominal voltage)

The voltage at the low voltage bus is:

$$V_{415V} = V_{11kV} \frac{Z_{S2}}{Z_{C3} + + Z_{TX1} + Z_{S2}}$$

$$= 9,521.825 - j280.698 = 9,525.6$$ Vac, then referred to the LV side = 359.39Vac (or 86.60% of nominal voltage)

Any other voltages of interest on the system can be determined using the same methods as above.

Suppose that our maximum voltage drop at the motor terminals is 15%. From above, we have found that the voltage drop is 12.08% at the motor terminals. This is a slightly marginal result and it may be prudent to simulate the system in a software package to confirm the results.

Computer Software

Motor starting is a standard component of most power systems analysis software (e.g. ETAP, PTW, ERAC, etc) and this calculation is really intended to be done using this software. The numerical calculation performed by the software should also solve the power flow problem through an iterative algorithm (e.g. such as Newton-Rhapson).

What Next?

If the results of the calculation confirm that starting the largest motor does not cause any unacceptable voltage levels within the system, then that's the end of it (or perhaps it could be simulated in a power systems analysis software package to be doubly sure!). Otherwise, the issue needs to be addressed, for example by:

- Reduce the motor starting current, e.g. via soft-starters, star-delta starters, etc
- Reduce the source impedances, e.g. increase the size of the generator, transformer, supply cables, etc

The calculation should be performed iteratively until the results are acceptable.

Short Circuit Calculation

Contents

Introduction

This article looks at the calculation of short circuit currents for bolted three-phase and single-phase to earth faults in a power system. A short circuit in a power system can cause very high currents to flow to the fault location. The magnitude of the short circuit current depends on the impedance of system under short circuit conditions. In this calculation, the short circuit current is estimated using the guidelines presented in IEC 60909.

Why do the calculation?

Calculating the prospective short circuit levels in a power system is important for a number of reasons, including:

- To specify fault ratings for electrical equipment (e.g. short circuit withstand ratings)
- To help identify potential problems and weaknesses in the system and assist in system planning
- To form the basis for protection coordination studies

When to do the calculation?

The calculation can be done after preliminary system design, with the following pre-requisite documents and design tasks completed:

- Key single line diagrams
- Major electrical equipment sized (e.g. generators, transformers, etc)
- Electrical load schedule
- Cable sizing (not absolutely necessary, but would be useful)

Calculation Methodology

This calculation is based on IEC 60909-0 (2001, c2002), "Short-circuit currents in three-phase a.c. systems - Part 0: Calculation of currents" and uses the impedance method (as opposed to the per-unit method). In this method, it is assumed that all short circuits are of negligible impedance (i.e. no arc impedance is allowed for).

There are six general steps in the calculation:

- Step 1: Construct the system model and collect the relevant equipment parameters
- Step 2: Calculate the short circuit impedances for all of the relevant equipment
- Step 3: Refer all impedances to the reference voltage
- Step 4: Determine the Thévenin equivalent circuit at the fault loca or
- Step 5: Calculate balanced three-phase short circuit currents
- Step 6: Calculate single-phase to earth short circuit currents

Step 1: Construct the System Model and Collect Equipment Parameters

The first step is to construct a model of the system single line diagram, and then collect the relevant equipment parameters. The model of the single line diagram should show all of the major system buses, generation or network connection, transformers, fault limiters (e.g. reactors), large cable interconnections and large rotating loads (e.g. synchronous and asynchronous motors).

The relevant equipment parameters to be collected are as follows:

- Network feeders: fault capacity of the network (VA), X/R ratio of the network
- Synchronous generators and motors: per-unit sub-transient reactance, rated generator capacity (VA), rated power factor (pu)
- Transformers: transformer impedance voltage (%), rated transformer capacity (VA), rated current (A), total copper loss (W)
- Cables: length of cable (m), resistance and reactance of cable ($\Omega\ km$)
- Asynchronous motors: full load current (A), locked rotor current (A), rated power (W), full load power factor (pu), starting power factor (pu)
- Fault limiting reactors: reactor impedance voltage (%), rated current (A)

Step 2: Calculate Equipment Short Circuit Impedances

Using the collected parameters, each of the equipment item impedances can be calculated for later use in the motor starting calculations.

Network Feeders

Given the approximate fault level of the network feeder at the connection point (or point of common coupling), the impedance, resistance and reactance of the network feeder is calculated as follows:

$$Z_f = \frac{cV_n^2}{S_f}$$

$$R_f = \frac{Z_f}{\sqrt{1 + \left(\frac{X}{R}\right)^2}}$$

$$X_f = \frac{X}{R} \times R_f$$

Where Z_f is impedance of the network feeder (Ω)

R_f is resistance of the network feeder (Ω)

X_f is reactance of the network feeder (Ω)

V_n is the nominal voltage at the connection point (Vac)

S_f is the fault level of the network feeder (VA)

c is a voltage factor which accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

$\frac{X}{R}$ is X/R ratio of the network feeder (pu)

Synchronous Generators and Motors

The sub-transient reactance and resistance of a synchronous generator or motor (with voltage regulation) can be estimated by the following:

$$X_d'' = \chi_d'' \times K_g \times \frac{V_g^2}{S_g}$$

$$R_g = \frac{X_d''}{\frac{X}{R}}$$

$$K_g = \frac{V_n}{V_g} \frac{c}{1 + \chi_d' \sin \phi_g}$$

Where X_d'' is the sub-transient reactance of the generator (Ω)

R_g is the resistance of the generator (Ω)

K_g is a voltage correction factor - see IEC 60909-0 Clause 3.6.1 for more details (pu)

χ_d'' is the per-unit sub-transient reactance of the generator (pu)

V_g is the nominal generator voltage (Vac)

V_n is the nominal system voltage (Vac)

S_g is the rated generator capacity (VA)

$\frac{X}{R}$ is the X/R ra o, typically 20 for $S_g \geq$ 100MVA, 14.29 for $S_g <$ 100MVA, and 6.67 for all generators with nominal voltage $V_g \leq$ 1kV

c is a voltage factor which accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

$\cos \phi_g$ is the power factor of the generator (pu)

For the negative sequence impedance, the quadrature axis sub-transient reactance X_q'' can be applied in the above equation in place of the direct axis sub-transient reactance X_d'' .

The zero-sequence impedances need to be derived from manufacturer data; though the voltage correction factor K_g also applies for solid neutral earthing systems (refer to IEC 60909-0 Clause 3.6.1).

Transformers

The positive sequence impedance, resistance and reactance of two-winding distribution transformers can be calculated as follows:

$$Z_t = u_k \frac{V_t^2}{S_t}$$

$$R_t = \frac{P_{kt}}{3I_t^2}$$

$$X_t = \sqrt{Z_t^2 - R_t^2}$$

Where Z_t is the positive sequence impedance of the transformer (Ω)

R_t is the resistance of the transformer (Ω)

X_t is the reactance of the transformer (Ω)

u_k is the impedance voltage of the transformer (pu)

S_t is the rated capacity of the transformer (VA)

V_t is the nominal voltage of the transformer at the high or low voltage side (Vac)

I_t is the rated current of the transformer at the high or low voltage side (I)

P_{kt} is the total copper loss in the transformer windings (W)

For the calculation of impedances for three-winding transformers, refer to IEC 60909-0 Clause 3.3.2. For network transformers (those that connect two separate networks at different voltages), an impedance correction factor must be applied (see IEC 60909-0 Clause 3.3.3).

The negative sequence impedance is equal to positive sequence impedance calculated above. The zero sequence impedance needs to be derived from manufacturer data, but also depends on the winding connections and fault path available for zero-sequence current flow (e.g. different neutral earthing systems will affect zero-sequence impedance).

Cables

Cable impedances are usually quoted by manufacturers in terms of Ohms per km. These need to be converted to Ohms based on the length of the cables:

$$R_c = R \times \frac{L_c}{1000}$$

$$X_c = X \times \frac{L_c}{1000}$$

Where R_c is the resistance of the cable {Ω)

X_c is the reactance of the cable {Ω)

R is the quoted resistance of the cable {Ω / *km*)

X is the quoted reactance of the cable {Ω / *km*)

L_c is the length of the cable {m)

The negative sequence impedance is equal to positive sequence impedance calculated above. The zero sequence impedance needs to be derived from manufacturer data. In the absence of manufacturer data, zero sequence impedances can be derived from positive sequence impedances via a multiplication factor (as suggested by SKM Systems Analysis Inc) for magnetic cables:

$$R_{c(0)} = R_c \times 3.15155$$

$$X_{c(0)} = R_c \times 2.46274$$

Asynchronous Motors

An asynchronous motor's impedance, resistance and reactance is calculated as follows:

$$Z_m = \frac{1}{I_{LRC}/I_{FLC}} \times \frac{V_m^2 \cos\phi_m}{P_m}$$

$$R_m = \frac{P_m \times I_{LRC}/I_{FLC} \times \cos\phi_s}{3I_{LRC}^2 \times \cos\phi_m}$$

$$X_m = \sqrt{Z_m^2 - R_m^2}$$

Where Z_m is impedance of the motor (Ω)

R_m is resistance of the motor (Ω)

X_m is reactance of the motor (Ω)

I_{LRC}/I_{FLC} is ratio of the locked rotor to full load current

I_{LRC} is the motor locked rotor current (A)

V_m is the motor nominal voltage (Vac)

P_m is the motor rated power (W)

$\cos\phi_m$ is the motor full load power factor (pu)

$\cos\phi_s$ is the motor starting power factor (pu)

The negative sequence impedance is equal to positive sequence impedance calculated above. The zero sequence impedance needs to be derived from manufacturer data.

Fault Limiting Reactors

The impedance of fault limiting reactors is as follows (note that the resistance is neglected):

$$Z_r = X_r = \frac{u_k \times V_n}{|sqrt3I_r}$$

Where Z_r is impedance of the reactor (Ω)

X_r is reactance of the reactor(Ω)

u_k is the impedance voltage of the reactor (pu)

V_n is the nominal voltage of the reactor (Vac)

I_r is the rated current of the reactor (A)

Positive, negative and zero sequence impedances are all equal (assuming geometric symmetry).

Other Equipment

Static converters feeding rotating loads may need to be considered, and should be treated similarly to asynchronous motors.

Line capacitances, parallel admittances and non-rotating loads are generally neglected as per IEC 60909-0 Clause 3.10. Effects from series capacitors can also be neglected if voltage-limiting devices are connected in parallel.

Step 3: Referring Impedances

Where there are multiple voltage levels, the equipment impedances calculated earlier need to be converted to a reference voltage (typically the voltage at the fault location) in order for them to be used in a single equivalent circuit.

The winding ratio of a transformer can be calculated as follows:

$$n = \frac{V_{t2}(1 + t_p)}{V_{t1}}$$

Where n is the transformer winding ratio

V_{t2} is the transformer nominal secondary voltage at the principal tap (Vac)

V_{t1} is the transformer nominal primary voltage (Vac)

t_p is the specified tap setting (%)

Using the winding ratio, impedances (as well as resistances and reactances) can be referred to the primary (HV) side of the transformer by the following relation:

$$Z_{HV} = \frac{Z_{LV}}{n^2}$$

Where Z_{HV} is the impedance referred to the primary (HV) side (Ω)

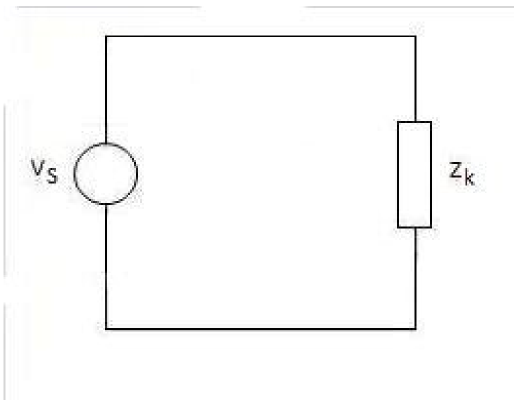
Z_{LV} is the impedance at the secondary (LV) side (Ω)

n is the transformer winding ratio (pu)

Conversely, by re-arranging the equation above, impedances can be referred to the LV side:

$$Z_{LV} = Z_{HV} \times n^2$$

Step 4: Determine Thévenin Equivalent Circuit at the Fault Location



Thévenin equivalent circuit

The system model must first be simplified into an equivalent circuit as seen from the fault location, showing a voltage source and a set of complex impedances representing the power system equipment and load impedances (connected in series or parallel).

The next step is to simplify the circuit into a Thévenin equivalent circuit, which is a circuit containing only a voltage source (V_s) and an equivalent short circuit impedance (Z_k).

This can be done using the standard formulae for series and parallel impedances, keeping in mind that the rules of complex arithmetic must be used throughout.

If unbalanced short circuits (e.g. single phase to earth fault) will be analyzed, then a separate Thévenin equivalent circuit should be constructed for each of the positive, negative and zero sequence networks (i.e. finding ($Z_{k(1)}$, $Z_{k(2)}$ and $Z_{k(0)}$).

Step 5: Calculate Balanced Three-Phase Short Circuit Currents

The positive sequence impedance calculated in Step 4 represents the equivalent source impedance seen by a balanced three-phase short circuit at the fault location. Using this impedance, the following currents at different stages of the short circle cycle can be computed:

Initial Short Circuit Current

The initial symmetrical short circuit current is calculated from IEC 60909-0 Equation 29, as follows:

$$I_k'' = \frac{cV_n}{\sqrt{3}Z_k}$$

Where I_k'' is the initial symmetrical short circuit current (A)

c is the voltage factor that accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

V_n is the nominal system voltage at the fault location (V)

Z_k is the equivalent positive sequence short circuit impedance (Ω)

Peak Short Circuit Current

IEC 60909-0 Section 4.3 offers three methods for calculating peak short circuit currents, but for the sake of simplicity, we will only focus on the X/R ratio at the fault location method. Using the real (R) and reactive (X) components of the equivalent positive sequence impedance Z_k, we can calculate the X/R ratio at the fault location, i.e.

$$X/R = \frac{X_k}{R_k}$$

The peak short circuit current is then calculated as follows:

$$I_p = 1.15\kappa \times \sqrt{2} I_k''$$

Where I_p is the peak short circuit current (A)

I_k'' is the initial symmetrical short circuit current (A)

κ is a constant factor, $\kappa = 1.02 + 0.98e^{-\frac{3}{X/R}}$

Symmetrical Breaking Current

The symmetrical breaking current is the short circuit current at the point of circuit breaker opening (usually somewhere between 20ms to 300ms). This is the current that the circuit breaker must be rated to interrupt and is typically used for breaker sizing. IEC 60909-0 Equation 74 suggests that the symmetrical breaking current for meshed networks can be conservatively estimated as follows:

$$I_b = I_k''$$

Where I_b is the symmetrical breaking current (A)

I_k'' is the initial symmetrical short circuit current (A)

More detailed calculations can be made for increased accuracy (e.g. IEC 60909-0 equations 75 to 77), but this is left to the reader to explore.

DC Short Circuit Component

The dc component of a short circuit can be calculated according to IEC 60909-0 Equation 64:

$$I_{dc} = \sqrt{2} I_k'' e^{\frac{-2\pi f t}{X/R}}$$

Where I_{dc} is the dc component of the short circuit current (A)

I_k'' is the initial symmetrical short circuit current (A)

f is the nominal system frequency (Hz)

t is the time (s)

X/R is the X/R ratio - see more below

The X/R ratio is calculated as follows:

$$X/R = \frac{X_k}{R_k}\frac{f}{f_c}$$

Where X_k and R_k are the reactance and resistance, respectively, of the equivalent source impedance at the fault location (Ω)

$\frac{f}{f_c}$ is a factor to account for the equivalent frequency of the fault. Per IEC 60909-0 Sec on 4.4, the following factors should be used based on the product of frequency and time ($f.t$):

$f.t$	$\frac{f}{f_c}$
<1	0.27
<2.5	0.15
<5	0.092
<12.5	0.055

Step 6: Calculate Single-Phase to Earth Short Circuit Currents

For balanced short circuit calculations, the positive-sequence impedance is the only relevant impedance. However, for unbalanced short circuits (e.g. single phase to earth fault), symmetrical components come into play.

The initial short circuit current for a single phase to earth fault is as per IEC 60909-0 Equation 52:

$$I''_{kl} = \frac{\sqrt{3}cV_n}{Z_{k(1)} + Z_{k(2)} + Z_{k(0)}}$$

Where I''_{kl} is the initial single phase to earth short circuit current (A)

c is the voltage factor that accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

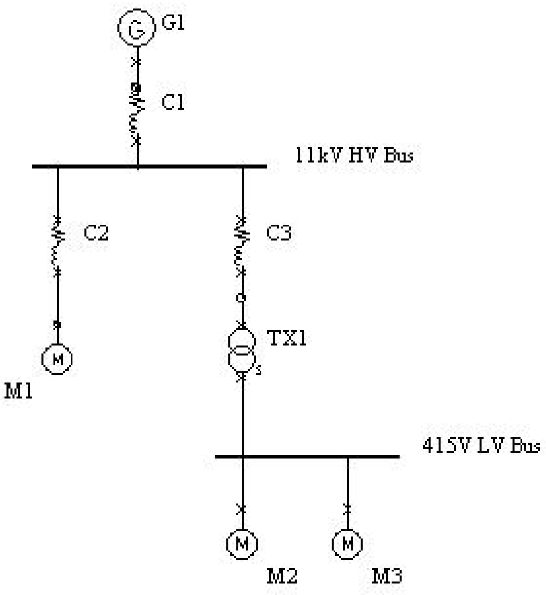
V_n is the nominal voltage at the fault location (Vac)

$Z_{k(1)}$ is the equivalent positive sequence short circuit impedance (Ω)

$Z_{k(2)}$ is the equivalent negative sequence short circuit impedance (Ω)

$Z_{k(0)}$ is the equivalent zero sequence short circuit impedance (Ω)

Worked Example



System model for short circuit example

In this example, short circuit currents will be calculated for a balanced three-phase fault at the main 11kV bus of a simple radial system. Note that the single phase to earth fault currents will not be calculated in this example.

Step 1: Construct the System Model and Collect Equipment Parameters

The system to be modeled is a simple radial network with two voltage levels (11kV and 415V), and supplied by a single generator. The system model is shown in the figure to the right. The equipment and cable parameters were collected as follows:

Equipment	Parameters
Generator G1	• S_{g1} = 24,150 kVA • V_{g1} = 11,000 V • X''_d = 0.255 pu • $\cos\phi$ = 0.85 pu
Generator Cable C1	• Length = 30m • Size = 2 parallel circuits of 3 x 1C x 500 mm^2 (R = 0.0506 Ω\km, X = 0.0997 Ω\km)
Motor M1	• P_{m1} = 500 kW • V_{m1} = 11,000 V • I_{LRC} = 200.7 A • I_{LRC}/I_{FLC} = 6.5 pu • $\cos\phi_m$ = 0.85 pu • $\cos\phi_s$ = 0.30 pu
Motor Cable C2	• Length = 150m • Size = 3C+E 35 mm^2 (R = 0.668 Ω\km, X = 0.115 Ω\km)
Transformer TX1	• S_{tx1} = 2,500 kVA • V_{t1} = 11,000 V • V_{t2} = 415 V • u_k = 0.0625 pu • P_{kt} = 19,000 W • t_p = 0%
Transformer Cable C3	• Length = 100m • Size = 3C+E 95 mm^2 (R = 0.247 Ω\km, X = 0.0993 Ω\km)
Motor M2	• P_{m1} = 90 kW • V_{m1} = 415 V • I_{LRC} = 1,217.3 A • I_{LRC}/I_{FLC} = 7 pu • $\cos\phi_m$ = 0.8 pu • $\cos\phi_s$ = 0.30 pu
Motor M3	• P_{m1} = 150 kW • V_{m1} = 415 V • I_{LRC} = 1,595.8 A • I_{LRC}/I_{FLC} = 6.5 pu

	• $\cos\phi_m$ = 0.85 pu • $\cos\phi_s$ = 0.30 pu

Step 2: Calculate Equipment Short Circuit Impedances

Using the parameters above and the equations outlined earlier in the methodology, the following impedances were calculated:

Equipment	Resistance (Ω)	Reactance (Ω)
Generator G1	0.01785	1.2390
Generator Cable C1	0.000759	0.001496
11kV Motor M1	9.4938	30.1885
Motor Cable C2	0.1002	0.01725
Transformer TX1 (Primary Side)	0.36784	3.0026
Transformer Cable C3	0.0247	0.00993
415V Motor M2	0.0656	0.2086
415V Motor M3	0.0450	0.1432

Step 3: Referring Impedances

We will model a fault on the main 11kV bus, so all impedances must be referred to 11kV. The two low voltage motors need to be referred to this reference voltage. Knowing that the transformer is set at principal tap, we can calculate the winding ratio and apply it to refer the 415V motors to the 11kV side:

$$n = \frac{415\,(1 + 0\%)}{11,000} = 0.03773$$

The 415V motor impedances referred to the 11kV side is therefore:

Equipment	Resistance (Ω)	Reactance (Ω)
415V Motor M2	46.0952	146.5735
415V Motor M3	31.6462	100.6284

Step 4: Determine Thévenin Equivalent Circuit at the Fault Location

Using standard network reduction techniques, the equivalent Thévenin circuit at the fault location (main 11kV bus) can be derived. The equivalent source impedance is:

$$Z_k = [Z_{G1} + Z_{C1}] \,||\, [Z_{M1}|Z_{C2}] \,||\, [Z_{C3} + Z_{TX1} + (Z_{M2}||Z_{M3})]$$
$$= 0.01855 + j1.16931$$

Step 5: Calculate Balanced Three-Phase Short Circuit Currents

Initial Short Circuit Current

The symmetrical initial short circuit current is:

$$I_k'' = \frac{cV_n}{\sqrt{3}Z_k}$$

$$= 0.09478 - j5.9729 = 5.9737 \text{ kA}$$

Peak Short Circuit Current

The constant factor κ at the fault location is:

$$\kappa = 1.02 + 0.98e^{\frac{3}{X/R}}$$

$$= 1.9514$$

Therefore the symmetrical peak short circuit current is:

$$I_p = 1.15\kappa \times \sqrt{2}I_k''$$

$$= 16.5112 \text{ kA}$$

Symmetrical Breaking Current

The symmetrical breaking current is:

$$I_b = I_k'' = 5.9737 \text{ kA}$$

Computer Software

Short circuit calculations are a standard component of power systems analysis software (e.g. ETAP, EasyPower, PTW, DIgSILENT, etc) and the calculations are far easier to perform with software than by hand. However manual calculations could be done as a form of verification to confirm that the software results are reasonable.

What Next?

The results from the short circuit calculations can be used to specify the fault ratings on electrical equipment (e.g. switchgear, protective devices, etc) and also for protection coordination studies.

Earthing Calculation

Contents

Introduction

The earthing system in a plant / facility is very important for a few reasons, all of which are related to either the protection of people and equipment and/or the optimal operation of the electrical system. These include:

- Equipotential bonding of conductive objects (e.g. metallic equipment, buildings, piping etc) to the earthing system prevents the presence of dangerous voltages between objects (and earth).
- The earthing system provides a low resistance return path for earth faults within the plant, which protects both personnel and equipment
- For earth faults with return paths to offsite generation sources, a low resistance earthing grid relative to remote earth prevents dangerous ground potential rises (touch and step potentials)
- The earthing system provides a low resistance path (relative to remote earth) for voltage transients such as lightning and surges / overvoltages
- Equipotential bonding helps prevent electrostatic buildup and discharge, which can cause sparks with enough energy to ignite flammable atmospheres
- The earthing system provides a reference potential for electronic circuits and helps reduce electrical noise for electronic, instrumentation and communication systems

This calculation is based primarily on the guidelines provided by IEEE Std 80 (2000), "Guide for safety in AC substation grounding". Lightning protection is excluded from the scope of this calculation (refer to the specific lightning protection calculation for more details).

Why do the calculation?

The earthing calculation aids in the proper design of the earthing system. Using the results of this calculation, you can:

- Determine the minimum size of the earthing conductors required for the main earth grid
- Ensure that the earthing design is appropriate to prevent dangerous step and touch potentials (if this is necessary)

When to do the calculation?

This calculation should be performed when the earthing system is being designed. It could also be done after the preliminary design has been completed to confirm that the earthing system is adequate, or highlight the need for improvement / redesign. Ideally, soil resistivity test results from the site will be available for use in touch and step potential calculations (if necessary).

When is the calculation unnecessary?

The sizing of earthing conductors should always be performed, but touch and step potential calculations (per IEEE Std 80 for earth faults with a return path through remote earth) are not always necessary.

For example, when all electricity is generated on-site and the HV/MV/LV earthing systems are interconnected, then there is no need to do a touch and step potential calculation. In such a case, all earth faults would return to the source via the earthing system (notwithstanding some small leakage through earth).

However, where there are decoupled networks (e.g. long transmission lines to remote areas of the plant), then touch and step potential calculations should be performed for the remote area only.

Calculation Methodology

This calculation is based on IEEE Std. 80 (2000), "Guide for safety in AC substation grounding". There are two main parts to this calculation:

- Earthing grid conductor sizing
- Touch and step potential calculations

IEEE Std. 80 is quite descriptive, detailed and easy to follow, so only an overview will be presented here and IEEE Std. 80 should be consulted for further details (although references will be given herein).

Prerequisites

The following information is required / desirable before starting the calculation:

- A layout of the site
- Maximum earth fault current into the earthing grid
- Maximum fault clearing time
- Ambient (or soil) temperature at the site
- Soil resistivity measurements at the site (for touch and step only)
- Resistivity of any surface layers intended to be laid (for touch and step only)

Earthing Grid Conductor Sizing

Determining the minimum size of the earthing grid conductors is necessary to ensure that the earthing grid will be able to withstand the maximum earth fault current. Like a normal power cable under fault, the earthing grid conductors experience an adiabatic short circuit temperature rise. However unlike a fault on a normal cable, where the limiting temperature is that which would cause permanent damage to the cable's insulation, the temperature limit for earthing grid conductors is the melting point of the conductor. In other words, during the worst case earth fault, we don't want the earthing grid conductors to start melting!

The minimum conductor size capable of withstanding the adiabatic temperature rise associated with an earth fault is given by re-arranging IEEE Std 80 Equation 37:

$$A = i^2 t \sqrt{\left(\frac{\frac{\alpha_r \rho_r 10^4}{TCAP}}{\ln \left[1 + \left(\frac{T_m - T_a}{K_0 + T_a} \right) \right]} \right)}$$

Where A is the minimum cross-sectional area of the earthing grid conductor (*mm*²)

$i^2 t$ is the energy of the maximum earth fault ($A^2 s$)

T_m is the maximum allowable (fusing) temperature (ºC)

T_a is the ambient temperature (ºC)

α_r is the thermal coefficient of resistivity (ºC^{-1})

ρ_r is the resistivity of the earthing conductor ($\mu\Omega.cm$)

K_0 is $\left(\frac{1}{\alpha_r} - 20 \deg C\right)$

$TCAP$ is the thermal capacity of the conductor per unit volume(Jcm^{-3}ºC^{-1})

The material constants T_m, α_r, ρ_r and *TCAP* for common conductor materials can be found in IEEE Std 80 Table 1. For example. Commercial hard-drawn copper has material constants:

- T_m = 1084 ºC
- α_r = 0.00381 ºC^{-1}
- ρ_r = 1.78 $\mu\Omega.cm$
- $TCAP$ = 3.42 Jcm^{-3}ºC^{-1}.

As described in IEEE Std. 80 Section 11.3.1.1, there are alternative methods to formulate this equation, all of which can also be derived from first principles).

There are also additional factors that should be considered (e.g. taking into account future growth in fault levels), as discussed in IEEE Std. 80 Section 11.3.3.

Touch and Step Potential Calculations

When electricity is generated remotely and there are no return paths for earth faults other than the earth itself, then there is a risk that earth faults can cause dangerous voltage gradients in the earth around the site of the fault (called ground potential rises). This means that someone standing near the fault can receive a dangerous electrical shock due to:

- Touch voltages - there is a dangerous potential difference between the earth and a metallic object that a person is touching
- Step voltages - there is a dangerous voltage gradient between the feet of a person standing on earth

The earthing grid can be used to dissipate fault currents to remote earth and reduce the voltage gradients in the earth. The touch and step potential calculations are performed in order to assess whether the earthing grid can dissipate the fault currents so that dangerous touch and step voltages cannot exist.

Step 1: Soil Resistivity

The resistivity properties of the soil where the earthing grid will be laid is an important factor in determining the earthing grid's resistance with respect to remote earth. Soils with lower resistivity lead to lower overall grid resistances and potentially smaller earthing grid configurations can be designed (i.e. that comply with safe step and touch potentials).

It is good practice to perform soil resistivity tests on the site. There are a few standard methods for measuring soil resistivity (e.g. Wenner four-pin method). A good discussion on the interpretation of soil resistivity test measurements is found in IEEE Std. 80 Section 13.4.

Sometimes it isn't possible to conduct soil resistivity tests and an estimate must suffice. When estimating soil resistivity, it goes without saying that one should err on the side of caution and select a higher resistivity. IEEE

Std 80 Table 8 gives some guidance on range of soil resistivities based on the general characteristics of the soil (i.e. wet organic soil = 10 Ω.m, moist soil = 100 Ω.m, dry soil = 1,000 Ω.m and bedrock = 10,000 Ω.m).

Step 2: Surface Layer Materials

Applying a thin layer (0.08m - 0.15m) of high resistivity material (such as gravel, blue metal, crushed rock, etc) over the surface of the ground is commonly used to help protect against dangerous touch and step voltages. This is because the surface layer material increases the contact resistance between the soil (i.e. earth) and the feet of a person standing on it, thereby lowering the current flowing through the person in the event of a fault.

IEEE Std 80 Table 7 gives typical values for surface layer material resistivity in dry and wet conditions (e.g. 40mm crushed granite = 4,000 Ω.m (dry) and 1,200 Ω.m (wet)).

The effective resistance of a person's feet (with respect to earth) when standing on a surface layer is not the same as the surface layer resistance because the layer is not thick enough to have uniform resistivity in all directions. A surface layer derating factor needs to be applied in order to compute the effective foot resistance (with respect to earth) in the presence of a finite thickness of surface layer material. This derating factor can be approximated by an empirical formula as per IEEE Std 80 Equation 27:

$$C_s = 1 - \frac{0.09\left(1 - \frac{\rho}{\rho_s}\right)}{2h_s + 0.09}$$

Where C_s is the surface layer derating factor

ρ is the soil resistivity (Ω.m)

ρ_s is the resistivity of the surface layer material (Ω.m)

h_s is the thickness of the surface layer (m)

This derating factor will be used later in Step 5 when calculating the maximum allowable touch and step voltages.

Step 3: Earthing Grid Resistance

A good earthing grid has low resistance (with respect to remote earth) to minimise ground potential rise (GPR) and consequently avoid dangerous touch and step voltages. Calculating the earthing grid resistance usually goes hand in hand with earthing grid design - that is, you design the earthing grid to minimise grid resistance. The earthing grid resistance mainly depends on the area taken up by the earthing grid, the total length of buried earthing conductors and the number of earthing rods / electrodes.

IEEE Std 80 offers two alternative options for calculating the earthing grid resistance (with respect to remote earth) - 1) the simplified method (Section 14.2) and 2) the Schwarz equations (Section 14.3), both of which are outlined briefly below. IEEE Std 80 also includes methods for reducing soil resistivity (in Section 14.5) and a treatment for concrete-encased earthing electrodes (in Section 14.6).

Simplified Method

IEEE Std 80 Equation 52 gives the simplified method as modified by Sverak to include the effect of earthing grid depth:

$$R_g = \rho \left[\frac{1}{L_T} + \frac{1}{\sqrt{20A}} \left(1 + \frac{1}{1 + h\sqrt{20/A}} \right) \right]$$

Where R_g is the earthing grid resistance with respect to remote earth (Ω)

ρ is the soil resistivity (Ω.m)

L_T is the total length of buried conductors (m)

A is the total area occupied by the earthling grid (m^2)

Schwarz Equations

The Schwarz equations are a series of equations that are more accurate in modeling the effect of earthing rods / electrodes. The equations are found in IEEE Std 80 Equations 53, 54, 55 and 56, as follows:

$$R_g = \frac{R_1 R_2 - R_m^2}{R_1 + R_2 - 2R_m}$$

Where R_g is the earthing grid resistance with respect to remote earth (Ω)

R_1 is the earth resistance of the grid conductors (Ω)

R_2 is the earth resistance of the earthing electrodes (Ω)

R_m is the mutual earth resistance between the grid conductors and earthing electrodes (Ω)

And the grid, earthing electrode and mutual earth resistances are:

$$R_1 = \frac{\rho}{\pi L_c} \left[\ln\left(\frac{2L_c}{a'}\right) + \frac{k_1 L_c}{\sqrt{A}} - k_2 \right]$$

$$R_2 = \frac{\rho}{2\pi n_r L_R} \left[\ln\left(\frac{4L_R}{b}\right) - 1 + \frac{2k_1 L_r}{\sqrt{A}} \left(\sqrt{n_r} - 1\right)^2 \right]$$

$$R_m = \frac{\rho}{\pi L_c} \left[\ln\left(\frac{2L_c}{L_r}\right) + \frac{k_1 L_c}{\sqrt{A}} - k_2 + 1 \right]$$

Where ρ is the soil resistivity (Ω.m)

L_c is the total length of buried grid conductors (m)

a' is $\sqrt{r.2h}$ for conductors buried at depth h metres and with cross-sectional radius r metres, or simply r for grid conductors on the surface

A is the total area covered by the grid conductors (m^2)

L_r is the length of each earthing electrode (m)

L_R is the total length of earthing electrodes (m)

n_r is number of earthing electrodes in area A

b is the cross-sectional radius of an earthing electrode (m)

k_1 and k_2 are constant coefficients depending on the geometry of the grid

The coefficient k_1 can be approximated by the following:

- (1) For depth $h = 0$: $k_1 = -0.04L/R + 1.41$
- (2) For depth $h = \frac{1}{10}\sqrt{A}$: $k_1 = -0.05L/R + 1.20$
- (3) For depth $h = \frac{1}{6}\sqrt{A}$: $k_1 = -0.05L/R + 1.13$

The coefficient k_2 can be approximated by the following:

- (1) For depth $h = 0$: $k_2 = 0.15L/R + 5.50$
- (2) For depth $h = \frac{1}{10}\sqrt{A}$: $k_2 = 0.10L/R + 4.68$
- (3) For depth $h = \frac{1}{6}\sqrt{A}$: $k_2 = -0.05L/R + 4.40$

Where in both cases, L/R is the length-to-width ratio of the earthing grid.

Step 4: Maximum Grid Current

The maximum grid current is the worst case earth fault current that would flow via the earthing grid back to remote earth. To calculate the maximum grid current, you firstly need to calculate the worst case symmetrical earth fault current at the facility that would have a return path through remote earth (call this $I_{k,e}$). This can be found from the power systems studies or from manual calculation. Generally speaking, the highest relevant earth fault level will be on the primary side of the largest distribution transformer (i.e. either the terminals or the delta windings).

Current Division Factor

Not all of the earth fault current will flow back through remote earth. A portion of the earth fault current may have local return paths (e.g. local generation) or there could be alternative return paths other than remote earth (e.g. overhead earth return cables, buried pipes and cables, etc). Therefore a current division factor S_f must be applied to account for the proportion of the fault current flowing back through remote earth.

Computing the current division factor is a task that is specific to each project and the fault location and it may incorporate some subjectivity (i.e. "engineering judgment"). In any case, IEEE Std 80 Section 15.9 has a good discussion on calculating the current division factor. In the most conservative case, a current division factor of $S_f = 1$ can be applied, meaning that 100% of earth fault current flows back through remote earth.

The symmetrical grid current I_g is calculated by:

$$I_g = I_{k,e} S_f$$

Decrement Factor

The symmetrical grid current is not the maximum grid current because of asymmetry in short circuits, namely a dc current offset. This is captured by the decrement factor, which can be calculated from IEEE Std 80 Equation 79:

$$D_f = \sqrt{1 + \frac{T_a}{t_f}\left(1 - e^{\frac{-2t_f}{T_a}}\right)}$$

Where D_f is the decrement factor

t_f is the duration of the fault (s)

T_A is the dc time offset constant (see below)

The dc time offset constant is derived from IEEE Std 80 Equation 74:

$$T_A = \frac{X}{R} \cdot \frac{1}{2\pi f}$$

Where $\frac{X}{R}$ is the X/R ratio at the fault location

f is the system frequency (Hz)

The maximum grid current I_G is lastly calculated by:

$$I_G = I_g D_f$$

Step 5: Touch and Step Potential Criteria

One of the goals of a safe earthing grid is to protect people against lethal electric shocks in the event of an earth fault. The magnitude of ac electric current (at 50Hz or 60Hz) that a human body can withstand is typically in the range of 60 to 100mA, when ventricular fibrillation and heart stoppage can occur. The duration of an electric shock also contributes to the risk of mortality, so the speed at which faults are cleared is also vital. Given this, we need to prescribe maximum tolerable limits for touch and step voltages that do not lead to lethal shocks.

The maximum tolerable voltages for step and touch scenarios can be calculated empirically from IEEE Std Section 8.3 for body weights of 50kg and 70kg:

Touch voltage limit - the maximum potential difference between the surface potential and the potential of an earthed conducting structure during a fault (due to ground potential rise):

- 50kg person: $E_{touch,50} = (1000 + 1.5C_s\rho_s)\frac{0.116}{\sqrt{t_s}}$
- 70kg person: $E_{touch,70} = (1000 + 1.5C_s\rho_s)\frac{0.157}{\sqrt{t_s}}$

Step voltage limit - is the maximum difference in surface potential experience by a person bridging a distance of 1m with the feet without contact to any earthed object:

- 50kg person: $E_{step,50} = (1000 + 6C_s\rho_s)\frac{0.116}{\sqrt{t_s}}$
- 70kg person: $E_{step,70} = (1000 + 6C_s\rho_s)\frac{0.157}{\sqrt{t_s}}$

Where E_{touch} is the touch voltage limit (V)

E_{step} is the step voltage limit (V)

C_s is the surface layer derating factor (as calculated in Step 2)

ρ_s is the soil resistivity (Ω.m)

t_s is the maximum fault clearing time (s)

The choice of body weight (50kg or 70kg) depends on the expected weight of the personnel at the site. Typically, where women are expected to be on site, the conservative option is to choose 50kg.

Step 6: Ground Potential Rise (GPR)

Normally, the potential difference between the local earth around the site and remote earth is considered to be zero (i.e. they are at the same potential). However an earth faults (where the fault current flows back through remote earth), the flow of current through the earth causes local potential gradients in and around the site. The maximum potential difference between the site and remote earth is known as the ground potential rise (GPR). It is important to note that this is a **maximum** potential difference and that earth potentials around the site will vary relative to the point of fault.

The maximum GPR is calculated by:

$$GPR \quad I_G R_g$$

Where GPR is the maximum ground potential rise (V)

I_G is the maximum grid current found earlier in Step 4 (A)

R_g is the earthing grid resistance found earlier in Step 3 (Ω)

Step 7: Earthing Grid Design Veri ication

Now we just need to verify that the earthing grid design is safe for touch and step potential. If the maximum GPR calculated above does not exceed either of the touch and step voltage limits (from Step 5), then the grid design is safe.

However if it **does exceed** the touch and step voltage limits, then some further analysis is required to verify the design, namely the calculation of the maximum mesh and step voltages as per IEEE Std 80 Section 16.5.

Mesh Voltage Calculation

The mesh voltage is the maximum touch voltage within a mesh of an earthing grid and is derived from IEEE Std 80 Equation 80:

$$E_m = \frac{\rho_s K_m K_i I_G}{L_M}$$

Where :: ρ_s is the soil resistivity (Ω.m)

I_G is the maximum grid current found earlier in Step 4 (A)

K_m is the geometric spacing factor (see below)

K_i is the irregularity factor (see below)

L_M is the effective buried length of the grid (see below)

Geometric Spacing Factor Km

The geometric spacing factor K_m is calculated from IEEE Std 80 Equation 81:

$$K_m = \frac{1}{2\pi}\left[\ln\frac{D^2}{16h \times d} + \frac{(D+2h)^2}{8D \times d} - \frac{h}{4d}\right] + \frac{K_{ii}}{K_(h)}\ln\left[\frac{8}{\pi(2n-1)}\right]$$

Where D is the spacing between parallel grid conductors (m)

h is the depth of buried grid conductors (m)

d is the cross-sectional diameter of a grid conductor (m)

K_h is a weighting factor for depth of burial = $\sqrt{1+h}$

K_{ii} is a weighting factor for earth electrodes /rods on the corner mesh

- $K_{ii} = 1$ for grids with earth electrodes along the grid perimeter or corners
- $K_{ii} = \frac{1}{2n^{n/2}}$ for grids with no earth electrodes on the corners or on the perimeter

n is a geometric factor (see below)

Geometric Factor n

The geometric factor n is calculated from IEEE Std 80 Equation 85:

$$n = n_a \times n_b \times n_c \times n_d$$

With $n_a = \frac{2L_c}{L_p}$

$n_b = 1$ for square grids, or otherwise $n_b = \sqrt{\frac{L_p}{4\sqrt{A}}}$

$n_c = 1$ for square and rectangular grids, or otherwise $n_c = \left[\frac{L_x L_y}{A}\right]^{\frac{0.7A}{L_x L_y}}$

$n_d = 1$ for square, rectangular and L-shaped grids, or otherwise $n_d = \frac{D_m}{\sqrt{L_x^2 + L_y^2}}$

Where L_c is the total length of horizontal grid conductors (m)

L_p is the length of grid conductors on the perimeter (m)

A is the total area of the grid (m^2)

L_x and L_y are the maximum length of the grids in the x and y directions (m)

D_m is the maximum distance between any two points on the grid (m)

<u>Irregularity Factor Ki</u>

The irregularity factor K_i is calculated from IEEE Std 80 Equation 89:

$$K_i = 0.644 + 0.148n$$

Where n is the geometric factor derived above

<u>*Effective Buried Length* LM</u>

The effective buried length L_M is found as follows:

- For grids with few or no earthing electrodes (and none on corners or along the perimeter):

$$L_M = L_c + L_R$$

Where L_c is the total length of horizontal grid conductors (m)

L_R is the total length of earthing electrodes / rods (m)

- For grids with earthing electrodes on the corners and along the perimeter:

$$L_M = L_c + \left[1.55 + 1.22\left(\frac{L_r}{\sqrt{L_x^2 + L_y^2}}\right)\right] L_R$$

Where L_c is the total length of horizontal grid conductors (m)

L_R is the total length of earthing electrodes / rods (m)

L_r is the length of each earthing electrode / rod (m)

L_x and L_y are the maximum length of the grids in the x and y directions (m)

Step Voltage Calculation

The maximum allowable step voltage is calculated from IEEE Std 80 Equation 92:

$$E_s = \frac{\rho_s K_s K_i I_G}{L_S}$$

Where :: ρ_s is the soil resistivity (Ω.m)

I_G is the maximum grid current found earlier in Step 4 (A)

K_s is the geometric spacing factor (see below)

K_i is the irregularity factor (as derived above in the mesh voltage calculation)

L_S is the effective buried length of the grid (see below)

Geometric Spacing Factor Ks

The geometric spacing factor K_s based on IEEE Std 80 Equation 81 is applicable for burial depths between 0.25m and 2.5m:

$$K_s = \frac{1}{\pi}\left[\frac{1}{2h} + \frac{1}{D+h} + \frac{1}{D}\left(1 - 0.5^{n-2}\right)\right]$$

Where D is the spacing between parallel grid conductors (m)

h is the depth of buried grid conductors (m)

n is a geometric factor (as derived above in the mesh voltage calculation)

Effective Buried Length LS

The effective buried length L_S for all cases can be calculated by IEEE Std 80 Equation 93:

$$L_S = 0.75L_c + 0.85L_R$$

Where L_c is the total length of horizontal grid conductors (m)

L_R is the total length of earthing electrodes / rods (m)

What Now?

Now that the mesh and step voltages are calculated, compare them to the maximum tolerable touch and step voltages respectively. If:

- $E_m < E_{touch}$, and
- $E_s < E_{step}$

Then the earthing grid design is safe.

If not, however, then further work needs to be done. Some of the things that can be done to make the earthing grid design safe:

- Redesign the earthing grid to lower the grid resistance (e.g. more grid conductors, more earthing electrodes, increasing cross-sectional area of conductors, etc). Once this is done, re-compute the earthing grid resistance (see Step 3) and re-do the touch and step potential calculations.

- Limit the total earth fault current or create alternative earth fault return paths

- Consider soil treatments to lower the resistivity of the soil

- Greater use of high resistivity surface layer materials

Worked Example

In this example, the touch and step potential calculations for an earthing grid design will be performed. The proposed site is a small industrial facility with a network connection via a transmission line and a delta-wye connected transformer.

Step 1: Soil Resistivity

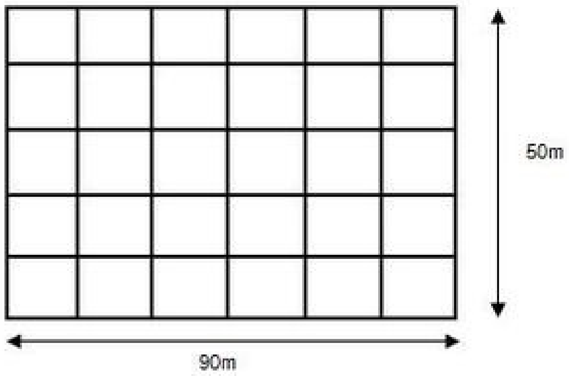
The soil resistivity around the site was measured with a Wenner four-pin probe and found to be approximately 300 Ω.m.

Step 2: Surface Layer Materials

A thin 100mm layer of blue metal (3,000 Ω.m) is proposed to be installed on the site. The surface layer derating factor is:

$$
\begin{aligned}
C_s &= 1 - \frac{0.09\left(1 - \frac{\rho}{\rho_s}\right)}{2h_s + 0.09} \\
&= 1 - \frac{0.09\left(1 - \frac{300}{3,000}\right)}{2 \times 0.1 + 0.09} \\
&= 0.7207
\end{aligned}
$$

Step 3: Earthing Grid Resistance



Proposed rectangular earthing grid

A rectangular earthing grid (see the figure right) with the following parameters is proposed:

- Length of 90m and a width of 50m
- 6 parallel rows and 7 parallel columns
- Grid conductors will be 120 mm^2 and buried at a depth of 600mm
- 22 earthing rods will be installed on the corners and perimeter of the grid
- Each earthing rod will be 3m long

Using the simplified equation, the resistance of the earthing grid with respect to remote earth is:

$$R_g = \rho \left[\frac{1}{L_T} + \frac{1}{\sqrt{20A}} \left(1 + \frac{1}{1 + h\sqrt{20/A}} \right) \right]$$

$$= 300 \left[\frac{1}{996} + \frac{1}{\sqrt{20 \times 4,500}} \left(1 + \frac{1}{1 + 0.6\sqrt{20/4,500}} \right) \right]$$

$$= 2.2627\Omega$$

Step 4: Maximum Grid Current

Suppose that the maximum single phase to earth fault at the HV winding of the transformer is 3.1kA and that the current division factor is 1 (all the fault current flows back to remote earth).

The X/R ratio at the fault is approximately 15, the maximum fault duration 150ms and the system nominal frequency is 50Hz. The DC time offset is therefore:

$$T_A = \frac{X}{R} \cdot \frac{1}{2\pi f}$$

$$= 15 \times \frac{1}{2\pi 50}$$

$$= 0.04774$$

The decrement factor is then:

$$D_f = \sqrt{1 + \frac{T_a}{t_f}\left(1 - e^{\frac{-2t_f}{T_a}}\right)}$$

$$= \sqrt{1 + \frac{0.04774}{0.15}\left(1 - e^{\frac{-2\times 0.15}{0.04774}}\right)}$$

$$= 1.1479$$

Finally, the maximum grid current is:

$$I_G = I_g D_f$$

$$= 3.1 \times 1.1479$$

$$= 3.559 \text{ kA}$$

Step 5: Touch and Step Potential Criteria

Based on the average weight of the workers on the site, a body weight of 70kg is assumed for the maximum touch and step potential. A maximum fault clearing time of 150ms is also assumed.

The maximum allowable touch potential is:

$$E_{touch,70} = (1000 + 1.5C_s\rho_s)\frac{0.157}{\sqrt{t_s}}$$

$$= (1000 + 1.5 \times 0.7207 \times 3,000)\frac{0.157}{\sqrt{0.15}}$$

$$= 1,720.04 \text{ V}$$

The maximum allowable step potential is:

$$E_{step,70} = (1000 + 6C_s\rho_s)\frac{0.157}{\sqrt{t_s}}$$

$$= (1000 + 6 \times 0.7207 \times 3,000)\frac{0.157}{\sqrt{0.15}}$$

$$= 5,664.03 \text{ V}$$

Step 6: Ground Potential Rise (GPR)

The maximum ground potential rise is:

$$GPR = I_G R_g$$

$$= 3,559 \times 2.2627$$

$$= 8,052 \text{ V}$$

The GPR far exceeds the maximum allowable touch and step potentials, and further analysis of mesh and step voltages need to be performed.

Step 7: Earthing Grid Design Verification

Mesh Voltage Calculation

The components of the geometric factor n_a , n_b , n_c and n_d for the rectangular grid are:

$$n_a = \frac{2L_c}{L_p}$$

$$= \frac{2 \times 930}{280} = 6.643$$

$$n_b = \sqrt{\frac{L_p}{4\sqrt{A}}}$$

$$= \sqrt{\frac{280}{4\sqrt{4500}}} = 1.022$$

$$n_c = n_d = 1$$

Therefore the geometric factor n is:

$$n = n_a \times n_b \times n_c \times n_d$$

$$= 6.643 \times 1.022 \times 1 \times 1$$

$$= 6.7858$$

The geometric spacing factor K_m is:

$$K_m = \frac{1}{2\pi}\left[\ln\frac{D^2}{16h \times d} + \frac{(D+2h)^2}{8D \times d} - \frac{h}{4d}\right] + \frac{K_{ii}}{K_h}\ln\left[\frac{8}{\pi(2n-1)}\right]$$

$$K_m = \frac{1}{2\pi}\left[\ln\frac{13.17^2}{16 \times 0.6 \times 0.0124} + \frac{(13.17 + 2 \times 0.6)^2}{8 \times 13.17 \times 0.0124} - \frac{0.6}{4 \times 0.0124}\right] + \frac{1}{1.26}\ln\left[\frac{8}{\pi(2 \times 6.7858 - 1)}\right]$$

$$= 0.9740$$

The irregularity factor K_i is:

$$K_i = 0.644 + 0.148n$$

$$= 0.644 + 0.148 \times 6.7858$$

$$= 1.6483$$

The effective buried length L_M is:

$$L_M = L_c + \left[1.55 + 1.22\left(\frac{L_r}{\sqrt{L_x^2 + L_y^2}}\right)\right] L_R$$

$$= 930 + \left[1.55 + 1.22\left(\frac{66}{\sqrt{90^2 + 50^2}}\right)\right] \times 66$$

$$= 1,034.65 \text{ m}$$

Finally, the maximum mesh voltage is:

$$E_m = \frac{\rho_s K_m K_i I_G}{L_M}$$

$$= \frac{300 \times 0.9740 \times 1.6483 \times 3,559}{1,034.65}$$

$$= 1,657 \text{ V}$$

The maximum allowable touch potential is 1,720V, which exceeds the mesh voltage calculated above and the earthing system passes the touch potential criteria (although it is quite marginal).

Step Voltage Calculation

The geometric spacing factor K_s is:

$$K_s = \frac{1}{\pi}\left[\frac{1}{2h} + \frac{1}{D+h} + \frac{1}{D}\left(1 - 0.5^{n-2}\right)\right]$$

$$= \frac{1}{\pi}\left[\frac{1}{2 \times 0.6} + \frac{1}{13.17 + 0.6} + \frac{1}{13.17}\left(1 - 0.5^{6.7857-2}\right)\right]$$

$$= 0.3117$$

The effective buried length L_S is:

$$L_S = 0.75L_c + 0.85L_R$$

$$= 0.75 \times 930 + 0.85 \times 66$$

$$= 753.6 \text{ m}$$

Finally, the maximum allowable step voltage is:

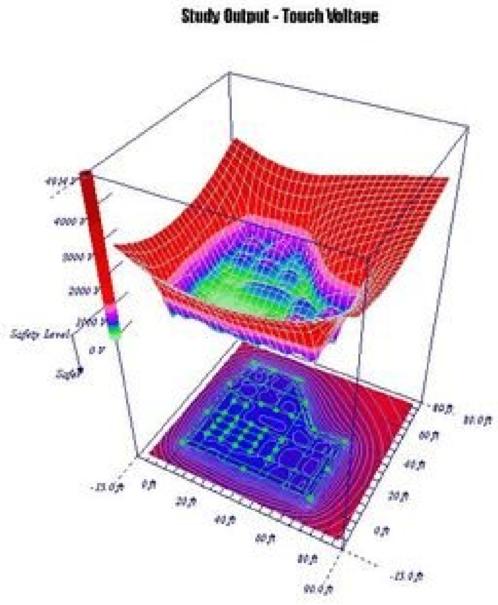
$$E_s = \frac{\rho_s K_s K_i I_G}{L_S}$$

$$= \frac{300 \times 0.3117 \times 1.6483 \times 3,559}{753.6}$$

$$= 728 \text{ V}$$

The maximum allowable step potential is 5,664V, which exceeds the step voltage calculated above and the earthing system passes the step potential criteria. Having passed both touch and step potential criteria, we can conclude that the earthing system is safe.

Computer Based Tools



PTW GroundMat software output (courtesy of SKM Systems Analysis Inc)

As can be seen from above, touch and step potential calculations can be quite a tedious and laborious task, and one that could conceivably be done much quicker by a computer. Even IEEE Std 80 recommends the use of computer software to calculate grid resistances, and mesh and step voltages, and also to create potential gradient visualizations of the site.

Computer software packages can be used to assist in earthing grid design by modeling and simulation of different earthing grid configurations. The tools either come as standalone packages or plug-in modules to power system analysis software (such as PTW's GroundMat or ETAP's Ground Grid Design Assessment. Examples of standalone packages include SES Autogrid and SafeGrid.

What next?

The minimum size for the earthing grid conductors can be used to specify the earthing grid conductor sizes in the material take-offs and earthing drawings. The touch and step potential calculations (where necessary) verify that the earthing grid design is safe for the worst earth faults to remote earth. The earthing drawings can therefore be approved for the next stage of reviews.

AC UPS Sizing

Contents

Introduction

This calculation deals with the sizing of an AC uninterruptible power supply (UPS) system (i.e. rectifier, battery bank and inverter). In this calculation, it is assumed that the AC UPS is a double conversion type with a basic system topology as shown in Figure 1.

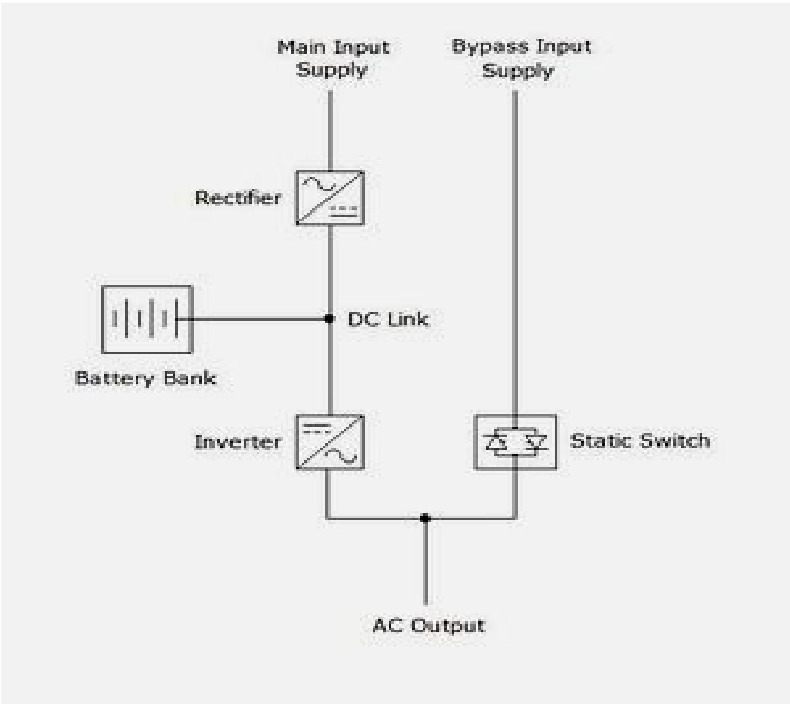


Figure 1 - AC UPS basic system topology

An external maintenance bypass switch and galvanic isolation transformers are other common additions to the basic topology, but these have been omitted from the system as they are irrelevant for the sizing calculation.

Why do the calculation?

An AC UPS system is used to support critical / sensitive AC loads. It is typically a battery-backed system which will continue to operate for a specified amount of time (called the autonomy) after a main power supply interruption. AC UPS systems are also used as stable power supplies that provide a reasonably constant voltage and frequency output, independent of voltage input. This is particularly useful for sensitive electrical equipment on main power supplies that are prone to voltage / frequency fluctuations or instability.

The AC UPS sizing calculation determines the ratings for the main AC UPS system components: 1) rectifier, 2) battery banks and 3) inverter.

In some cases, the manufacturer will independently size the system and it is only necessary to construct the AC UPS load schedule and load profile. However the calculation results will also help determine the indicative dimensions of the equipment (e.g. size of battery banks) for preliminary layout purposes.

When to do the calculation?

The AC UPS sizing calculation can be done when the following prerequisite information is known:

- UPS loads that need to be supported
- Input / Output AC voltage
- Autonomy time(s)
- Battery type

Calculation Methodology

The calculation procedure has four main steps:

1) Determine and collect the prospec ve AC UPS load

2) Construct a load profile and determine the UPS design load (VA) and design energy (VAh)

3) Calculate the size of the sta onary ba ery (number of cells in series and Ah capacit

4) Determine the size of the inverter, rectifier/ charger and static switch

Step 1: Collect the AC UPS Loads

The first step is to determine the type and quantity of loads that the AC UPS system will be expected to support. For industrial facilities, this will typically be critical instrumentation and control loads such as the DCS and ESD processor and marshalling hardware, critical workstations and HMI's, telecommunications equipment and sensitive electronics. The necessary load data should be available from the instrumentation and control engineers.

For commercial facilities, UPS loads will mainly be server, data / network and telecommunications hardware.

Step 2: Load Profile, Design Load and Design Energy

Refer to the Load Profile Calculation for details on how to construct a load profile, calculate the design load (S_d) and design energy (E_d). The "Autonomy method" for constructing load profiles is typically used for AC UPS systems.

The autonomy time is often specified by the Client (i.e. in their standards). Alternatively, IEEE 446, "IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications" has some guidance (particularly Table 3-2) for autonomy times. Sometimes a single autonomy time is used for the entire AC UPS load, which obviously makes the construction of the load profile easier to compute.

Step 3: Battery Sizing

Refer to the Battery Sizing Calculation for details on how to size the battery for the AC UPS system. The following sections provide additional information specific to battery sizing for AC UPS applications.

Nominal Battery (or DC Link) Voltage

The nominal battery / DC link voltage is often selected by the AC UPS manufacturer. However, if required to be selected, the following factors need to be considered:

- DC output voltage range of the rectifier – the rectifier must be able to output the specified DC link voltage
- DC input voltage range of the inverter – the DC link voltage must be within the input voltage tolerances of the inverter. Note that the battery end of discharge voltage should be within these tolerances.
- Number of battery cells required in series – this will affect the overall dimensions and size of the battery rack. If physical space is a constraint, then less batteries in series would be preferable.
- Total DC link current (at full load) – this will affect the sizing of the DC cables and inter-cell battery links. Obviously the smaller the better.

In general, the DC link voltage is usually selected to be close to the nominal output voltage.

Number of Cells in Series

The number of battery cells required to be connected in series must be between the two following limits:

$$N_{max} = \frac{V_{dc}(1 + V_{i,max})}{V_f} \quad (1)$$

$$N_{min} = \frac{V_{dc}(1 - V_{i,min})}{V_{eod}} \quad (2)$$

where N_{max} is the maximum number of battery cells

N_{min} is the minimum number of battery cells

V_{dc} is the nominal battery / DC link voltage (Vdc)

$V_{i,max}$ is the inverter maximum input voltage tolerance (%)

$V_{i,min}$ is the inverter minimum input voltage tolerance (%)

V_f is the nominal cell float (or boost) voltage (Vdc)

V_{eod} is the cell end of discharge voltage (Vdc)

The limits are based on the input voltage tolerance of the inverter. As a maximum, the battery at float voltage (or boost if applicable) needs to be within the maximum input voltage range of the inverter. Likewise as a minimum, the battery at its end of discharge voltage must be within the minimum input voltage range of the inverter.

Select the number of cells in between these two limits (more or less arbitrary, though somewhere in the middle of the min/max values would be appropriate).

Step 4: UPS Sizing

Overall UPS Sizing

Most of the time, all you need to provide is the overall UPS kVA rating and the UPS vendor will do the rest. Given the design load (S_d in VA or kVA) calculated in Step 2, select an overall UPS rating that exceeds the design load. Vendors typically have standard UPS ratings, so it is possible to simply select the first standard rating that exceeds the design load. For example, if the design load 12kVA, then the next size unit (e.g. 15kVA UPS) would be selected.

Rectifier / Charger Sizing

The rectifier / charger should be sized to supply the inverter at full load and also charge the batteries (at the maximum charge current). The design DC load current can be calculated by:

$$I_{L,dc} = \frac{S}{V_{dc}}$$

where $I_{L,dc}$ is the design DC load current (full load) (A)

S is the selected UPS rating (kVA)

V_{dc} is the nominal battery / DC link voltage (Vdc)

The maximum battery charging current can be computed as follows:

$$I_c = \frac{C k_l}{t_c}$$

where I_c is the maximum DC charge current (A)

C is the selected battery capacity (Ah)

k_l is the ba ery recharge efficiency / loss factor (typically 1.1) (pu

t_c is the minimum battery recharge time (hours)

The total minimum DC rectifier / charger current is therefore:

$$I_{dc} = I_{L,dc} + I_c$$

Select the next standard rectifier / charger rating that exceeds the total minimum DC current above.

Inverter Sizing

The inverter must be rated to continuously supply the UPS loads. Therefore, the inverter can be sized using the design AC load current (based on the selected UPS kVA rating).

For a three-phase UPS:

$$I_L = \frac{S}{\sqrt{3}V_o}$$

For a single-phase UPS:

$$I_L = \frac{S}{V_o}$$

where I_L is the design AC load current (full load) (A)

S is the selected UPS rating (kVA)

V_o is the nominal output voltage (line-to-line voltage for a three phase UPS) (Vac)

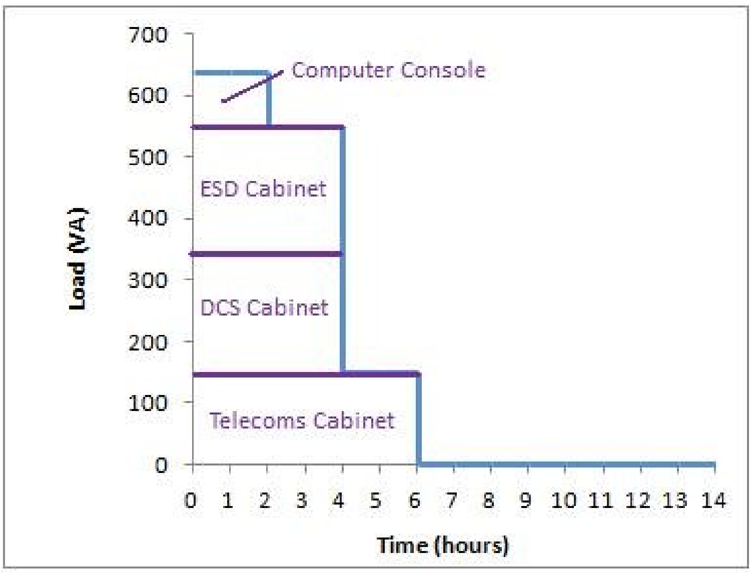
Select the next standard inverter rating that exceeds the design AC load current.

Static Switch Sizing

Like the inverter, the static switch must be rated to continuously supply the UPS loads. Therefore, the static switch can be sized using the design AC load current (as above for the inverter sizing).

Worked Example

Step 1 and 2: Collect the AC UPS Loads and Construct Load Profile



Load profile for this example

For this example, we shall use the same loads and load profile detailed in the Energy Load Profile Calculation example. The load profile is shown in the figure right and the following quantities were calculated:

- Design load S_d = 768 VA
- Design energy demand E_d = 3,216 VAh

Step 3: Battery Sizing

For this example, we shall use the same battery sizes calculated in the Battery Sizing Calculation worked example. The selected number of cells in series is 62 cells and the minimum battery capacity is 44.4 Ah. A battery capacity of 50 Ah is selected.

Step 4: UPS Sizing

Overall Sizing

Given the design load of 768 VA, then a 1 kVA UPS would be appropriate.

Rectifier Sizing

Given a nominal dc link voltage of 120Vdc, the design DC load current is:

$$I_{L,dc} = \frac{S}{V_{dc}}$$

$$= \frac{1,000}{120} = 8.33 \text{ A}$$

Suppose the minimum battery recharge time is 2 hours and a recharge efficiency factor of 1.1 is used. The maximum battery charging current is:

$$I_c = \frac{C k_l}{t_c}$$

$$= \frac{50 \times 1.1}{2} = 27.5 \text{ A}$$

Therefore the total minimum DC rectifier / charger current is:

$$I_{dc} = I_{L,dc} + I_c$$

$$= 8.33 + 27.5 = 35.83 \text{ A}$$

A DC rectifier rating of 40A is selected.

Inverter and Static Switch Sizing

Suppose the nominal output voltage is 240Vac. The design AC load current is:

$$I_L = \frac{S}{\sqrt{3} V_o}$$

$$= \frac{1,000}{\sqrt{3} \times 240} = 2.406 \text{ A}$$

An inverter and static switch rating of 5A is selected.

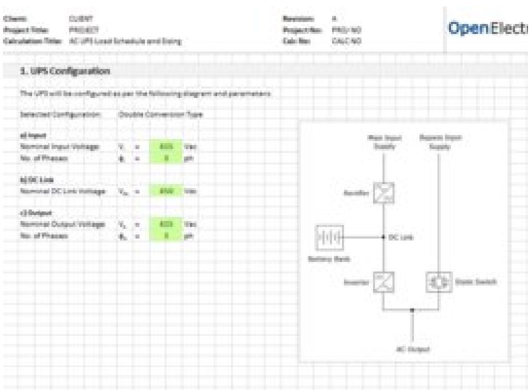
Template

A professional, fully customizable Excel spreadsheet template of the AC UPS calculation can be purchased from Lulu.

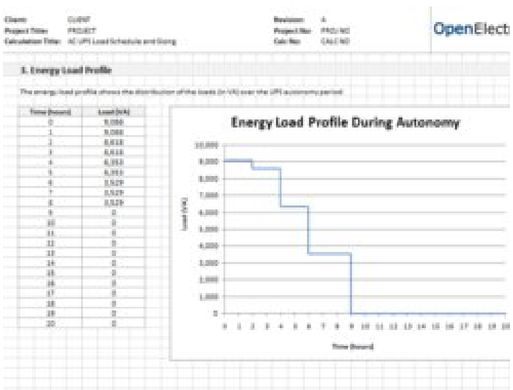
The template is based on the calculation procedure described in this page and includes the following features:

- Load schedule and automatic load profile generation
- Battery sizing
- UPS component sizing (e.g. rectifier, inverter, etc)

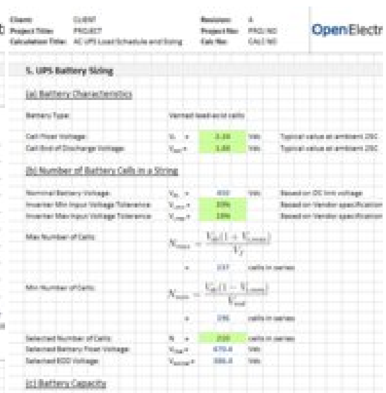
Screenshots from AC UPS Template



UPS Configuration



Load Profile



Battery Sizing

Computer Software

Preliminary sizing is normally done manually. Notwithstanding this, many AC UPS manufacturers provide sizing tools as part of their service package (for example, see the APC online UPS selector tool).

What next?

Using the results of the UPS sizing calculation, the approximate dimensions of the batteries and UPS cabinet can be estimated based on typical vendor information. This will assist in developing the equipment / room layouts. Preliminary budget pricing can also be estimated based on the calculation results.

Battery Sizing

Contents

Introduction

Stationary batteries on a rack (courtesy of Power Battery)

This article looks at the sizing of batteries for stationary applications (i.e. they don't move). Batteries are used in many applications such as AC and DC uninterruptible power supply (UPS) systems, solar power systems, telecommunications, emergency lighting, etc. Whatever the application, batteries are seen as a mature, proven technology for storing electrical energy. In addition to storage, batteries are also used as a means for providing voltage support for weak power systems (e.g. at the end of small, long transmission lines).

Why do the calculation?

Sizing a stationary battery is important to ensure that the loads being supplied or the power system being supported are adequately catered for by the battery for the period of time (i.e. autonomy) for which it is designed. Improper battery sizing can lead to poor autonomy times, permanent damage to battery cells from over-discharge, low load voltages, etc.

When to do the calculation?

The calculation can typically be started when the following information is known:

- Battery loads that need to be supported
- Nominal battery voltage
- Autonomy time(s)

Calculation Methodology

The calculation is based on a mixture of normal industry practice and technical standards IEEE Std 485 (1997, R2003) "Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications" and IEEE Std 1115 (2000, R2005) "Recommended Practice for Sizing Nickel-Cadmium Batteries for Stationary Applications". The calculation is based on the ampere-hour method for sizing battery capacity (rather than sizing by positive plates).

The focus of this calculation is on standard lead-acid or nickel-cadmium (NiCd) batteries, so please consult specific supplier information for other types of batteries (e.g. lithium-ion, nickel-metal hydride, etc). Note also that the design of the battery charger is beyond the scope of this calculation.

There are five main steps in this calculation:

1) Collect the loads that the battery needs to support
2) Construct a load profile and calculate the design energy (VAh)
3) Select the battery type and determine the characteristics of the cell
4) Select the number of battery cells to be connected in series
5) Calculate the required Ampere-hour (Ah) capacity of the battery

Step 1: Collect the battery loads

The first step is to determine the loads that the battery will be supporting. This is largely specific to the application of the battery, for example an AC UPS System or a Solar Power System.

Step 2: Construct the Load Profile

Refer to the Load Profile Calculation for details on how to construct a load profile and calculate the design energy, E_d, in VAh.

The autonomy time is often specified by the Client (i.e. in their standards). Alternatively, IEEE 446, "IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications" has some guidance (particularly Table 3-2) for autonomy times. Note that IEEE 485 and IEEE 1115 refer to the load profile as the "duty cycle".

Step 3: Select Battery Type

The next step is to select the battery type (e.g. sealed lead-acid, nickel-cadmium, etc). The selection process is not covered in detail here, but the following factors should be taken into account (as suggested by IEEE):

- Physical characteristics, e.g. dimensions, weight, container material, intercell connections, terminals
- application design life and expected life of cell
- Frequency and depth of discharge
- Ambient temperature
- Charging characteristics
- Maintenance requirements
- Ventilation requirements
- Cell orientation requirements (sealed lead-acid and NiCd)
- Seismic factors (shock and vibration)

Next, find the characteristics of the battery cells, typically from supplier data sheets. The characteristics that should be collected include:

- Battery cell capacities (Ah)
- Cell temperature
- Electrolyte density at full charge (for lead-acid batteries)
- Cell float voltage

- Cell end-of-discharge voltage (EODV).

Battery manufacturers will often quote battery Ah capacities based on a number of different EODVs. For lead-acid batteries, the selection of an EODV is largely based on an EODV that prevents damage of the cell through over-discharge (from over-expansion of the cell plates). Typically, 1.75V to 1.8V per cell is used when discharging over longer than 1 hour. For short discharge durations (i.e. <15 minutes), lower EODVs of around 1.67V per cell may be used without damaging the cell.

Nickel-Cadmium (NiCd) don't suffer from damaged cells due to over-discharge. Typical EODVs for Ni-Cd batteries are 1.0V to 1.14V per cell.

Step 4: Number of Cells in Series

The most common number of cells for a specific voltage rating is shown below:

Rated Voltage	Lead-Acid	Ni-Cd
12V	6	9-10
24V	12	18-20
48V	24	36-40
125V	60	92-100
250V	120	184-200

However, the number of cells in a battery can also be calculated to more accurately match the tolerances of the load. The number of battery cells required to be connected in series must fall between the two following limits:

(1) $$N_{max} = \frac{V_{dc}(1 + V_{l,max})}{V_c}$$

(2) $$N_{min} = \frac{V_{dc}(1 - V_{l,min})}{V_{eod}}$$

where N_{max} is the maximum number of battery cells

N_{min} is the minimum number of battery cells
V_{dc} is the nominal battery voltage (Vdc)
$V_{l,max}$ is the maximum load voltage tolerance (%)
$V_{l,min}$ is the minimum load voltage tolerance (%)
V_c is the cell charging voltage (Vdc)
V_{eod} is the cell end of discharge voltage (Vdc)

The limits are based on the minimum and maximum voltage tolerances of the load. As a maximum, the battery at float voltage (or boost voltage if applicable) needs to be within the maximum voltage range of the load. Likewise as a minimum, the battery at its end of discharge voltage must be within the minimum voltage range of the load. The cell charging voltage depends on the type of charge cycle that is being used, e.g. float, boost, equalizing, etc, and the maximum value should be chosen.

Select the number of cells in between these two limits (more or less arbitrary, though somewhere in the middle of the min/max values would be most appropriate).

Step 5: Determine Battery Capacity

The minimum battery capacity required to accommodate the design load over the specified autonomy time can be calculated as follows:

$$C_{min} = \frac{E_d(k_a \times k_t \times k_c)}{V_{dc} \times k_{dod}}$$

where C_{min} is the minimum battery capacity (Ah)

E_d is the design energy over the autonomy time (VAh)
V_{dc} is the nominal battery voltage (Vdc)
k_a is a battery ageing factor (%)
k_t is a temperature correction factor (%)
k_c is a capacity rating factor (%)
k_{dod} is the maximum depth of discharge (%)

Select a battery Ah capacity that exceeds the minimum capacity calculated above. The battery discharge rate (C rating) should also be specified, approximately the duration of discharge (e.g. for 8 hours of discharge, use the C8 rate). The selected battery specification is therefore the Ah capacity and the discharge rate (e.g. 500Ah C10).

Electrolyte temperature		Cell size correction factor
(°F)	(°C)	
25	−3.9	1.520
30	−1.1	1.430
35	1.7	1.350
40	4.4	1.300
45	7.2	1.250
50	10.0	1.190
55	12.8	1.150
60	15.6	1.110
65	18.3	1.080
66	18.9	1.072
67	19.4	1.064
68	20.0	1.056
69	20.6	1.048
70	21.1	1.040
71	21.7	1.034
72	22.2	1.029
73	22.8	1.023
74	23.4	1.017
75	23.9	1.011
76	24.5	1.006
77	25.0	1.000

Electrolyte temperature		Cell size correction factor
(°F)	(°C)	
78	25.6	0.994
79	26.1	0.987
80	26.7	0.980
81	27.2	0.976
82	27.8	0.972
83	28.3	0.968
84	28.9	0.964
85	29.4	0.960
86	30.0	0.956
87	30.6	0.952
88	31.1	0.948
89	31.6	0.944
90	32.2	0.940
95	35.0	0.930
100	37.8	0.910
105	40.6	0.890
110	43.3	0.880
115	46.1	0.870
120	48.9	0.860
125	51.7	0.850

NOTE—This table is based on vented lead-acid nominal 1.215 specific gravity. However, it may be used for vented cells with up to a 1.300 specific gravity. For cells of other designs, refer to the manufacturer.

Temperature correction factors for vented lead-acid cells (from IEEE 485)

An explanation of the different factors:

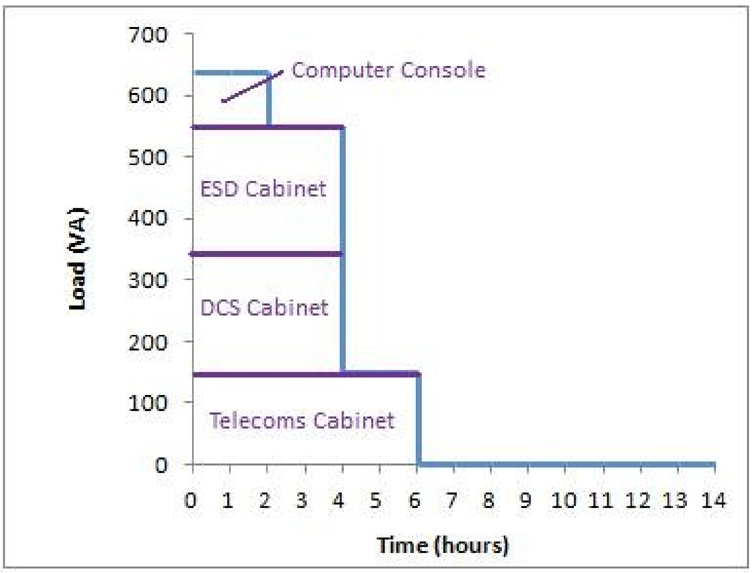
- **Ageing factor** captures the decrease in battery performance due to age.

The performance of a lead-acid battery is relatively stable but drops markedly at latter stages of life. The "knee point" of its life vs performance curve is approximately when the battery can deliver 80% of its rated capacity. After this point, the battery has reached the end of its useful life and should be replaced. Therefore, to ensure that battery can meet capacity throughout its useful life, an ageing factor of 1.25 should be applied (i.e. 1 / 0.8). There are some exceptions, check with the manufacturer.
For Ni-Cd batteries, the principles are similar to lead-acid cells. Please consult the battery manufacturer for suitable ageing factors, but generally, applying a factor of 1.25 is standard. For applications with high temperatures and/or frequent deep discharges, a higher factor of 1.43 may be used. For more shallower discharges, a lower factor of 1.11 can be used.

- **Temperature correction factor** is an allowance to capture the ambient installation temperature. The capacity for battery cells are typicall quoted for a standard operating temperature of 25C and where this differs with the installation temperature, a correction factor must be applied. IEEE 485 gives guidance for vented lead-acid cells (see figure right), however for sealed lead-acid and Ni-Cd cells, please consult manufacturer recommendations. Note that high temperatures lower battery life irrespective of capacity and the correction factor is for capacity sizing only, i.e. you CANNOT increase battery life by increasing capacity.

- **Capacity rating factor** accounts for voltage depressions during battery discharge. Lead-acid batteries experience a voltage dip during the early stages of discharge followed by some recovery. Ni-Cds may have lower voltages on discharge due to prolonged float charging (constant voltage). Both of these effects should be accounted for by the capacity rating factor - please see the manufacturer's recommendations. For Ni-Cd cells, IEEE 1115 Annex C suggests that for float charging applications, K_t = rated capacity in Ah / discharge current in Amps (for specified discharge time and EODV).

Worked Example



Load profile for this example

Step 1 and 2: Collect Battery Loads and Construct Load Profile

The loads and load profile from the simple example in the Energy Load Profile Calculation will be used (see the figure right). The design energy demand calculated for this system is E_d = 3,242.8 VAh.

Step 3: Select Battery Type

Vented lead acid batteries have been selected for this example.

Step 4: Number of Cells in Series

Suppose that the nominal battery voltage is V_{dc} = 120Vdc, the cell charging voltage is V_c = 2.25Vdc/cell, the end-of-discharge voltage is V_{eod} = 1.8Vdc/cell, and the minimum and maximum load voltage tolerances are $V_{l,min}$ = 10% and $V_{l,max}$ = 20% respectively.

The maximum number of cells in series is:

$$N_{max} = \frac{V_{dc}(1 + V_{l,max})}{V_c} = \frac{120 \times (1 + 0.2)}{2.25} = 64$$ cells

The minimum number of cells in series is:

$$N_{min} = \frac{V_{dc}(1 - V_{l,min})}{V_{eod}} = \frac{120 \times (1 - 0.1)}{1.8} = 60$$ cells

The selected number of cells in series is 62 cells.

Step 5: Determine Battery Capacity

Given a depth of discharge k_{dod} = 80%, battery ageing factor k_a = 25%, temperature correction factor for vented cells at 30 deg C of k_t = 0.956 and a capacity rating factor of k_c = 10%, the minimum battery capacity is:

$$C_{min} = \frac{E_d \times k_a \times k_c \times k_t}{V_{dc} \times k_{dod}} = \frac{3,242.8 \times 1.25 \times 1.1 \times 0.956}{120 \times 0.8} = 44.4$$ Ah

Computer Software

Some battery manufacturers (such as Alcad) also provide software programs to size batteries using basic input data such as load profiles, autonomies, etc. The software will size the batteries and will often also provide details regarding different battery rack (or enclosure) dimensions.

What Next?

Using the results of the battery sizing calculation, the approximate dimensions of the batteries can be estimated based on typical vendor information. This will assist in determining the size, number and dimensions of the battery racks or cabinets required, which can then be used as input into the equipment / room layouts. Preliminary budget pricing can also be estimated based on the calculation results.

Solar System Sizing

Contents

Introduction

Solar PV array

This calculation outlines the sizing of a standalone solar photovoltaic (PV) power system. Standalone PV systems are commonly used to supply power to small, remote installations (e.g. telecoms) where it isn't practical or cost-efficient to run a transmission line or have alternative generation such as diesel gensets.

Although this calculation is biased towards standalone solar PV systems, it can also be used for hybrid systems that draw power from mixed sources (e.g. commercial PV, hybrid wind-PV systems, etc). Loads must be adjusted according to the desired amount that the solar PV system will supply.

This calculation is based on crystalline silicon PV technology. The results may not hold for other types of solar PV technologies and the manufacturer's recommendations will need to be consulted.

Why do the calculation?

This calculation should be done whenever a solar PV power system is required so that the system is able to adequately cater for the necessary loads. The results can be used to determine the ratings of the system components (e.g. PV array, batteries, etc).

When to do the calculation?

The following pre-requisite information is required before performing the calculation:

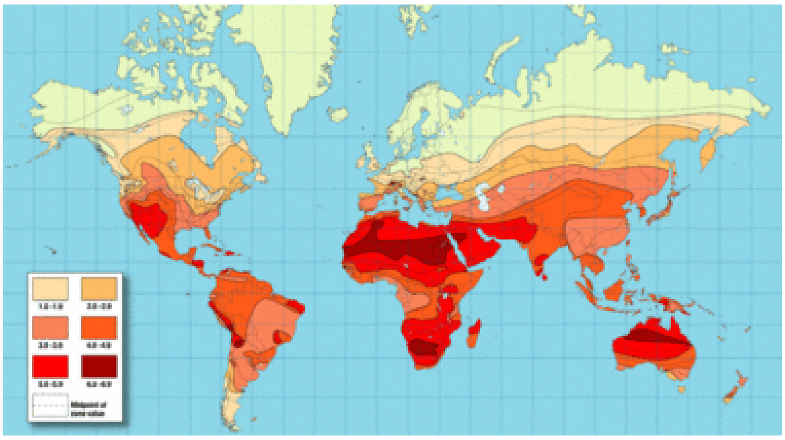
- Loads required to be supported by the solar PV system
- Autonomy time or minimum tolerable downtime (i.e. if there is no sun, how long can the system be out of service?)
- GPS coordinates of the site (or measurements of the solar insolation at the site)
- Output voltage (AC or DC)

Calculation Methodology

The calculation is loosely based on AS/NZS 4509.2 (2002) "Standalone power systems - System design guidelines". The methodology has the following six steps:

- Step 1: Es mate the solar irradia on available at the site (based on GPS coordinates or measurement)
- Step 2: Collect the loads that will be supported by the system
- Step 3: Construct a load profile and calculate design load and design energy
- Step 4: Calculate the required ba ery capacity based on the design loads
- Step 5: Es mate the output of a single PV module at the proposed site loca on
- Step 6: Calculate size of the PV array

Step 1: Estimate Solar Irradiation at the Site



World solar irradiation map

The first step is to determine the solar resource availability at the site. Solar resources are typically discussed in terms of solar radiation, which is more or less the catch-all term for sunlight shining on a surface. Solar radiation consists of three main components:

- **Direct or beam radiation** is made up of beams of unscattered and unreflected light reaching the surface in a straight line directly from the sun
- **Diffuse radiation** is scattered light reaching the surface from the whole sky (but not directly from the sun)
- **Albedo radiation** is light reflected onto the surface from the ground

Solar radiation can be quantitatively measured by irradiance and irradiation. Note that the terms are distinct - "irradiance" refers to the density of the **power** that falls on a surface (W / m^2) and "irradiation" is the density of the **energy** that falls on a surface over some period of time such as an hour or a day (e.g. Wh / m^2 per hour/day).

In this section, we will estimate the solar radiation available at the site based on data collected in the past. However, it needs to be stressed that solar radiation is statistically random in nature and there is inherent uncertainty in using past data to predict future irradiation. Therefore, we will need to build in design margins so that the system is robust to prediction error.

Baseline Solar Irradiation Data

The easiest option is to estimate the solar irradiation (or solar insolation) by inputting the GPS coordinates of the site into the NASA Surface Meteorology and Solar Resource website.

For any given set of GPS coordinates, the website provides first pass estimates of the monthly minimum, average and maximum solar irradiation (in $kWh / m^2 / day$) at ground level and at various tilt angles. Collect this data, choose an appropriate tilt angle and identify the best and worst months of the year in terms of solar irradiation. Alternatively, for US locations data from the National Solar Radiation Database can be used.

The minimum, average and maximum daytime temperatures at the site can also be determined from the public databases listed above. These temperatures will be used later when calculating the effective PV cell temperature.

Actual solar irradiation measurements can also be made at the site. Provided that the measurements are taken over a long enough period (or cross-referenced / combined with public data), then the measurements would provide a more accurate estimate of the solar irradiation at the site as they would capture site specific characteristics, e.g. any obstructions to solar radiation such as large buildings, trees, mountains, etc.

Solar Irradiation on an Inclined Plane

Most PV arrays are installed such that they face the equator at an incline to the horizontal (for maximum solar collection). The amount of solar irradiation collected on inclined surfaces is different to the amount collected on a horizontal surface. It is theoretically possible to accurately estimate the solar irradiation on any inclined surface given the solar irradiation on an horizontal plane and the tilt angle (there are numerous research papers on this topic, for example the work done by Liu and Jordan in 1960).

However, for the practical purpose of designing a solar PV system, we'll only look at estimating the solar irradiation at the **optimal tilt angle**, which is the incline that collects the most solar irradiation. The optimal tilt angle largely depends on the latitude of the site. At greater latitudes, the optimal tilt angle is higher as it favours summertime radiation collection over wintertime collection. The Handbook of Photovoltaic Science and Engineering suggests a linear approximation to calculating the optimal tilt angle:

$$\beta_{opt} = 3.7 + 0.69|\phi|$$

Where β_{opt} is the optimal tilt angle (deg)

ϕ is the latitude of the site (deg)

The handbook also suggests a polynomial approximation for the solar irradiation at the optimal tilt angle:

$$G(\beta_{opt}) = \frac{G(0)}{1 - 4.46 \times 10^{-4} \times \beta_{opt} - 1.19 \times 10^{-4} \times \beta_{opt}^2}$$

Where $G(\beta_{opt})$ is the solar irradiation on a surface at the optimal tilt angle (Wh / m^2)

$G(0)$ is the solar irradiation on the horizontal plane (Wh / m^2)

β_{opt} is the optimal tilt angle (deg)

Alternatively, the estimated irradiation data on tilted planes can be sourced directly from the various public databases listed above.

Solar Trackers

Solar trackers are mechanical devices that can track the position of the sun throughout the day and orient the PV array accordingly. The use of trackers can significantly increase the solar irradiation collected by a surface. Solar trackers typically increase irradiation by 1.2 to 1.4 times (for 1-axis trackers) and 1.3 to 1.5 times (for 2-axis trackers) compared to a fixed surface at the optimal tilt angle.

Non-Standard Applications

A solar irradiation loss factor should be used for applications where there are high tilt angles (e.g. vertical PV arrays as part of a building facade) or very low tilt angles (e.g. North-South horizontal trackers). This is because the the solar irradiation is significantly affected (detrimentally) when the angle of incidence is high or the solar radiation is mainly diffuse (i.e. no albedo effects from ground reflections). For more details on this loss factor, consult the standard ASHRAE 93, "Methods of testing to determine the thermal performance of solar collectors".

Step 2: Collect the Solar Power System Loads

The next step is to determine the type and quantity of loads that the solar power system needs to support. For remote industrial applications, such as metering stations, the loads are normally for control systems and instrumentation equipment. For commercial applications, such as telecommunications, the loads are the telecoms hardware and possibly some small area lighting for maintenance. For rural electrification and residential applications, the loads are typically domestic lighting and low-powered appliances, e.g. computers, radios, small tv's, etc.

Step 3: Construct a Load Profile

Refer to the Load Profile Calculation for details on how to construct a load profile and calculate the design load (S_d) and design energy (E_d). Typically, the "24 Hour Profile" method for constructing a load profile is used for Solar Power Systems.

Step 4: Battery Capacity Sizing

In a solar PV power system, the battery is used to provide backup energy storage and also to maintain output voltage stability. Refer to the Battery Sizing Calculation for details on how to size the battery for the solar power system.

Step 5: Estimate a Single PV Module's Output

It is assumed that a specific PV module type (e.g. Suntech STP070S-12Bb) has been selected and the following parameters collected:

- Peak module power, P_{stc} (W-p)
- Nominal voltage V_n (Vdc)

- Open circuit voltage V_{oc} (Vdc)
- Optimum operating voltage V_{mp} (Vdc)
- Short circuit current I_{sc} (A)
- Optimum operating current I_{mp} (A)
- Peak power temperature coefficient γ (% per deg C)
- Manufacturer's power output tolerance f_{man} (%)

Manufacturers usually quote these PV module parameters based on Standard Test Conditions (STC): an irradiance of 1,000 W / m^2, the standard reference spectral irradiance with Air Mass 1.5 (see the NREL site for more details) and a cell temperature of 25 deg C. Standard test conditions rarely prevail on site and when the PV module are installed in the field, the output must be de-rated accordingly.

Effective PV Cell Temperature

Firstly, the average effective PV cell temperature at the installation site needs to be calculated (as it will be used in the subsequent calculations). It can be estimated for each month using AS\NZS 4509.2 equation 3.4.3.7:

$$T_{cell,eff} = T_{a,day} + 25$$

Where $T_{cell,eff}$ is the average effective PV cell temperature (deg C)

$T_{a,day}$ is the average daytime ambient temperature at the site (deg C)

Standard Regulator

For a solar power system using a standard switched charge regulator / controller, the derated power output of the PV module can be calculated using AS\NZS 4509.2 equation 3.4.3.9(1):

$$P_{mod} = V_{ave} I_{T,V} \times f_{man} \times f_{dirt}$$

Where P_{mod} is the derated power output of the PV module using a standard switched charge controller (W)

V_{ave} is the daily average operating voltage (Vdc)

$I_{T,V}$ is the module output current based on the daily average operating voltage, at the effective average cell temperature and solar irradiance at the site - more on this below (A)

f_{man} is the manufacturer's power output tolerance (pu)

f_{dirt} is the dera ng factor for dirt / soiling (Clean: 1.0, Lov: 0.98, Med: 0.97, High: 0.92)

To estimate $I_{T,V}$, you will need the IV characteristic curve of the PV module at the effective cell temperature calculated above. For a switched regulator, the average PV module operating voltage is generally equal to the average battery voltage less voltage drops across the cables and regulator.

MPPT Regulator

For a solar power system using a Maximum Power Point Tracking (MPPT) charge regulator / controller, the derated power output of the PV module can be calculated using AS\NZS 4509.2 equation 3.4.3.9(2):

$$P_{mod} = P_{stc} \times f_{temp} \times f_{man} \times f_{dirt}$$

Where P_{mod} is the derated power output of the PV module using an MPPT charge controller (W)

P_{stc} is the nominal module power under standard test conditions (W)

f_{man} is the manufacturer's power output tolerance (pu)

f_{dirt} is the derating factor for dirt / soiling (Clean: 1.0, Low: 0.98, Med: 0.97, High: 0.92)

f_{temp} is the temperature derating factor - see below (pu)

The temperature derating factor is determined from AS\NZS 4509.2 equation 3.4.3.9(1):

$$f_{temp} = 1 - \gamma \left(T_{cell.eff} - T_{stc} \right)$$

Where f_{temp} is temperature derating factor (pu)

γ is the Power Temperature Coefficient (% per deg C)

$T_{cell.eff}$ is the average effective PV cell temperature (deg C)

T_{stc} is the temperature under standard test condi ons (typically 25 deg C

Step 6: Size the PV Array

The sizing of the PV array described below is based on the method outlined in AS/NZS 4509.2. There are alternative sizing methodologies, for example the method based on reliability in terms of loss of load probability (LLP), but these methods will not be further elaborated in this article. The fact that there is no commonly accepted sizing methodology reflects the difficulty of performing what is an inherently uncertain task (i.e. a prediction exercise with many random factors involved).

MPPT Controller

The number of PV modules required for the PV array can be found by using AS\NZS 4509.2 equation 3.4.3.11(2):

$$N = \frac{E_d \times f_o}{P_{mod} \times G \times \eta_{pvss}}$$

Where N is the number of PV modules required

P_{mod} is the derated power output of the PV module (W)

E_d is the total design daily energy (VAh)

f_o is the oversupply coefficient (pu)

G is the solar irradiation after all factors (e.g. tilt angle, tracking, etc) have been captured (*kWh* / *m*^{2} / *day*)

η_{pvss} is the efficiency of the PV sub-system (pu)

The oversupply coefficient f_o is a design contingency factor to capture the uncertainty in designing solar power systems where future solar irradiation is not deterministic. AS/NZS 4509.2 Table 1 recommends oversupply coefficients of between 1.3 and 2.0.

The efficiency of the PV sub-system η_{pvss} is the combined efficiencies of the charge regulator / controller, battery and transmission through the cable between the PV array and the battery. This will depend on specific circumstances (for example, the PV array a large distance from the battery), though an efficiency of around 90% would be typically used.

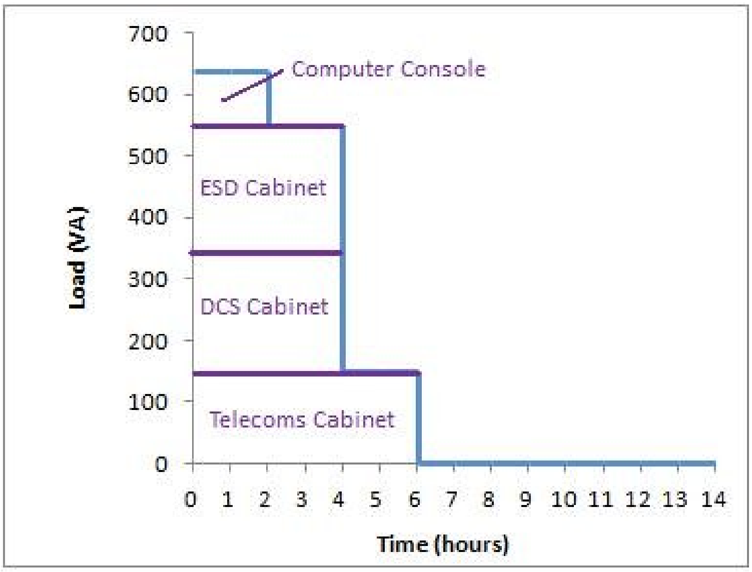
Worked Example

A small standalone solar power system will be designed for a telecommunications outpost located in the desert.

Step 1: Estimate Solar Irradiation at the Site

From site measurements, the solar irradiation at the site during the worst month at the optimal title angle is 4.05 kWh/m^2/day.

Step 2 and 3: Collect Loads and Construct a Load Profile



Load profile for this example

For this example, we shall use the same loads and load profile detailed in the Energy Load Profile Calculation example. The load profile is shown in the figure right and the following quantities were calculated:

- Design load S_d = 768 VA
- Design energy demand E_d = 3,216 VAh

Step 4: Battery Capacity Sizing

For this example, we shall use the same battery sizes calculated in the Battery Sizing Calculation] worked example. The selected number of cells in series is 62 cells and the minimum battery capacity is 44.4 Ah.

Step 5: Estimate a Single PV Module's Output

A PV module with the following characteristics is chosen:

- Peak module power, $P_{stc} = 120$ W-p
- Nominal voltage $V_n = 12$ Vdc
- Peak power temperature coefficient $\gamma = 0.38$ % per deg C
- Manufacturer's power output tolerance $f_{man} = 5$ %

Suppose the average daytime ambient temperature is 40C. The effective PV cell temperature is:

$$T_{cell,eff} = T_{a,day} + 25$$

$$= 40 + 25 = 65 \text{ deg C}$$

An MPPT controller will be used. The temperature derating factor is therefore:

$$f_{temp} = 1 - \gamma (T_{cell,eff} - T_{stc})$$

$$= 1 - 0.0038 \times (65 - 25) = 0.848$$

Given a medium dirt derating factor of 0.97, the derated power output of the PV module is:

$$P_{mod} = P_{stc} \times f_{temp} \times f_{man} \times f_{dirt}$$

$$= 120 \times 0.848 \times 0.95 \times 0.97 = 93.77 \text{ W}$$

Step 6: Size the PV Array

Given an oversupply coefficient of 1.1 and a PV sub-system efficiency of 85%, the number of PV modules required for the PV array is:

$$N = \frac{E_d \times f_o}{P_{mod} \times G \times \eta_{pcss}}$$

$$\frac{3.216 \times 1.1}{93.77 \times 4.05 \times 0.85} =$$ 10.9588 modules

For this PV array, 12 modules are selected.

Standard Regulator

The number of PV modules required for the PV array can be found by using AS\NZS 4509.2 equation 3.4.3.11(1):

$$N = \frac{E_d \times f_o}{P_{mod} \times G \times \eta_{coul}}$$

Where N is the number of PV modules required

P_{mod} is the derated power output of the PV module (W)

E_d is the total design daily energy (VAh)

f_o is the oversupply co-efficient (pu)

G is the solar irradiation after all factors (e.g. tilt angle, tracking, etc) have been captured ($kWh / m^2 / day$)

η_{coul} is the coulombic efficiency of the battery (pu)

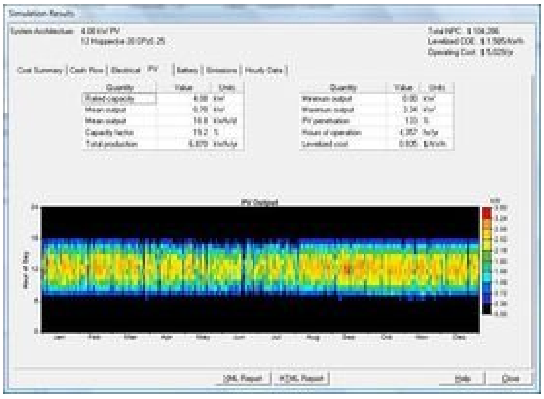
The oversupply coefficient f_o is a design contingency factor to capture the uncertainty in designing solar power systems where future solar irradiation is not deterministic. AS/NZS 4509.2 Table 1 recommends oversupply coefficients of between 1.3 and 2.0.

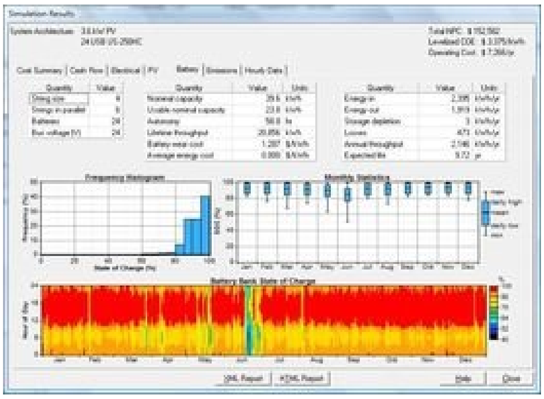
A battery coulombic efficiency of approximately 95% would be typically used.

Computer Software

It is recommended that the solar PV system sized in this calculation is simulated with computer software. For example, HOMER is a free software package for simulating and optimizing a distributed generation (DG) system originally developed by the National Renewable Energy Laboratory (NREL).

Screenshots from HOMER software





PV Output Battery Output

What Next?

With the sizing calculation completed, the solar PV equipment (PV array, batteries, charge controllers, etc) can be specified and a cost estimate or budget enquiry / requisition package issued. The approximate dimensions of the equipment (especially the PV array and batteries) can also be estimated and a design layout can be produced.

Guide to Electrical Cables

This guide is a structured directory of internal links on the subject of insulated electrical power, instrumentation and control cables ranging from very low (e.g. 24V) to high voltages (e.g. 115kV).

Contents

Construction

The overview of cable construction covers how typical low voltage, high voltage and instrumentation cables are put together and outlines the different constituent parts that make up a cable.

For details on the common types of materials used in cables, refer to the following links:

- Conductor materials
- Insulation materials
- Sheathing materials

Design / Sizing

Cable design and sizing resources:

- Cable sizing calculation presents a detailed methodology for sizing electrical cables based on international standards. The methodology outlines four main considerations that should be examined when designing and sizing cables - 1) current ra ng (or ampacity), 2) voltage drop, 3) short circuit temperature rise, and 4) earth fault loop impedance.

- Cablesizer is a free online cable sizing tool based on IEC standards.

- Cable impedance calculations provide details on how to calculate the dc resistance, ac resistance and inductive reactance of a cable.

- Low voltage cable reference pages give typical data on cable current ratings, derating factors, impedances, etc.

Specification

The construction of a cable is often described in a shorthand notation, which specifies the materials used in the cable layer by layer from the conductor up. For example, Cu/XLPE/PVC/SWA/PVC refers to copper conductors, XLPE insulation, PVC inner sheath, SWA armouring and PVC outer sheath.

Refer to following pages for details on:

- Cable Terminology for a description of commonly used cable abbreviations (e.g. EPR, XLPE, FR, GSWB, etc)
- NEC Cable Types for a list of the cable types for fixed wiring used in NFPA 70 (NEC) Ar cle 310.104
- Cable Color Codes for the common power cable insulation colour codes used in different regions around the world

Installation and Testing

Field testing of cables:

- Low voltage cable commissioning tests

Special Applications

Cables used in special applications tend to have different characteristics:

- Subsea power cables are cables installed fully-immersed in water. They are used commonly in offshore oil and gas facilities, and subsea power links between islands and offshore wind turbines.
- VSD / VFD cables for use in variable speed / frequency drives, which have special considerations and characteristics.

LV Cable Commissioning

Visual Inspection

- Check cable mechanical connections
- Check that cable colour codes conform to project specifications and/or national standards
- Verify cable tags / numbers

Electrical Testing

- For each test, record the testing instrument make / model and serial number.

- Perform insulation-resistance test (megger) on each conductor with respect to earth and adjacent conductors. For 0.6/1kV cables, an applied voltage of 1,000 Vdc for 1 minute is appropriate, with acceptance levels of 100 MΩ for new cables and 1 MΩ for aged cables.

- Perform continuity (point-to-point) tests to ensure proper cable connection and continuity. Where applicable, perform continuity tests on each phase to neutral and each phase to phase and record the readings in Ohms.

Guide to Electrical Testing

Under Construction

Types of Tests

Insulation tests:

- Insulation resistance test (Megger)
- Dielectric absorption test
- Dielectric withstand test (Hipot)
- High voltage tests
- Dissolved gas analysis
- Dielectric loss angle test
- Partial discharge test

Other tests:

- Contact resistance test (Ductor)
- Thermographic imaging surveys
- Frequency response analysis

Tests for Specific Equipment

- Dry-type transformer testing

Standards

- ANSI/NETA ATS, "Standard for Acceptance Testing Specifications for Electrical Power Equipment and Systems", 2009

Standard IEC Ratings

Contents

Introduction

Most IEC rated equipment have standard sizes that correspond to full sets or subsets of Reynard numbers, especially from the four preferred series of Reynard numbers outlined in ISO-3: R5, R10, R20 and R40.

Transformers

For transformer ratings under 10MVA, IEC 60076-1 suggest preferred values based on the R10 series: 10, 12.5, 16, 20, 25, 31.5, 40, 50, 63, 80, 100, and multiples of 10^n. For example, the preferred transformer sizes from 500kVA to 4000kVA are: 500, 630, 800, 1000, 1250, 1600, 2000, 2500, 3150, and 4000.

Motors and Generators

IEC 60072-1 Table 7 suggests the following preferred ratings (based on a subset of the R40 series)
For motors (in KW) and generators (in kVA):

0.06	0.09	0.12	0.18	0.25	0.37	0.55	0.75	1.1	1.5	1.8*	2.2	3*	3.7	4*	5.5	6.3*	7.5	10*	11	13*	15	17*	18.5
20*	22	25*	30	32*	37	40*	45	50*	55	63*	75	80*	90	100*	110	125*	132	150	160	185	200	220	250
280	300	315	335	355	375	400	425	450	475	500	530	560	600	630	670	710	750	800	850	900	950	1000	

(*) Note that these are "secondary series" ratings and are only to be used in cases of special need.

Cables

Standard cable sizes (in mm^2) are as follows:

0.5	0.75	1	1.5	2.5	4	6	10	16	25	35	50	70	95	120	150	185	240	300	400	500	630	800	1000

LV Cable Data

These pages provide reference data for low voltage 0.6/1kV cables. The data should be used as a rough guide in the absence of more specific information.

Base Current Ratings

- Cable Reference Installation Methods
- Copper Conductors:
  - PVC Current Ratings (Copper)
  - EPR or XLPE Current Ratings (Copper)
- Aluminum Conductors
  - PVC Current Ratings (Aluminum)
  - EPR or XLPE Current Ratings (Aluminum)

Derating Factors

- Above Ground:
  - Ambient Temperature Derating Factors
  - Grouping Derating Factors (Single Layer)
  - Grouping Derating Factors (Multiple Layers
- Below Ground:
  - Soil Temperature Derating Factors
  - Soil Thermal Resistivity Derating Factors
  - Grouping Derating Factors - Buried Direct
  - Grouping Derating Factors - Buried in Conduit

Cable Impedances

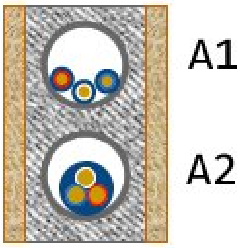
- AC Reactance of insulated conductors operating at 50Hz
- AC Resistance of insulated conductors operating at 50Hz
- DC Resistance of copper and aluminum conductors at 20°C

Refer also to the Cable Impedance Calculations article, which provides details on how the cable impedances are determined.

Cable Reference Installation Methods

Contents

Method A



- A1 - Insulated single core conductors in conduit in a thermally insulated wall
- A2 – Multi-core cable in conduit in a thermally insulated wall

This method also applies to single core or multi-core cables installed directly in a thermally insulated wall (use methods A1 and A2 respectively), conductors installed in mouldings, architraves and window frames.

Method B

- B1 - Insulated single core conductors in conduit on a wall
- B2 - Multicore cable in conduit on a wall

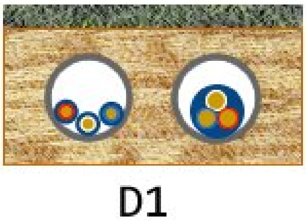
This method applies when a conduit is installed inside a wall, against a wall or spaced less than 0.3 x D (overall diameter of the cable) from the wall. Method B also applies for cables installed in trunking / cable duct against a wall or suspended from a wall and cables installed in building cavities.

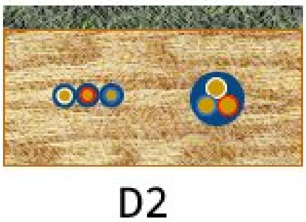
Method C

- C - Single core or multi-core cable on a wooden wall

This method also applies to cables fixed directly to walls or ceilings, suspended from ceilings, installed on unperforated cable trays (run horizontally or vertically) and installed directly in a masonry wall (with thermal resistivity less than 2 K.m/W).

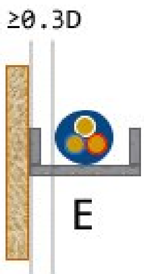
Method D





- D1 - Multicore or single core cables installed in conduit buried in the ground
- D2 - Multicore or single core cables buried directly in the ground

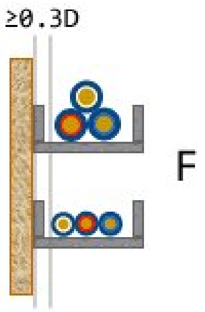
Method E



- E - Multicore cable in free-air

This method applies to cables installed on cable ladder, perforated cable tray or cleats provided that the cable is spaced more than 0.3 x D (overall diameter of the cable) from the wall. Note that cables installed on unperforated cable trays are classified under Method C.

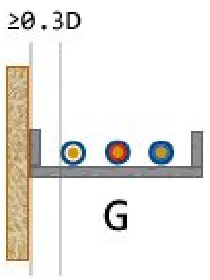
Method F



- F - Single core cables touching in free-air

This method applies to cables installed on cable ladder, perforated cable tray or cleats provided that the cable is spaced more than 0.3 x D (overall diameter of the cable) from the wall. Note that cables installed on unperforated cable trays are classified under Method C.

Method G



- G - Single-core cables laid flat and spaced in free-air

This method applies to cables installed on cable ladder, perforated cable tray or cleats provided that the cable is spaced more than 0.3 x D (overall diameter of the cable) from the wall and with at least 1 x D spacing’s between cables. Note that cables installed on un-perforated cable trays are classified under Method C. This method also applies to cables installed in air supported by insulators.

PVC Current Ratings (Copper)

Current ratings are based on values given in IEC 60364-5-52 (2009), with a reference conductor temperature of 70°C, ambient temperature of 30°C and soil temperature of 20°C.

Two Loaded Conductors

Size (mm^2)	Current Rating for 2 x PVC Insulated Copper Conductors								
	Reference Installation Method								
	A1	A2	B1	B2	C	D1	D2	E	F
1.5	14.5	14	17.5	16.5	19.5	22	22	22	–
2.5	19.5	18.5	24	23	27	29	28	30	–
4	26	25	32	30	36	37	38	40	–
6	34	32	41	38	46	46	48	51	–
10	46	43	57	52	63	60	64	70	–
16	61	57	76	69	85	78	83	94	–
25	80	75	101	90	112	99	110	119	131
35	99	92	125	111	138	119	132	148	162
50	119	110	151	133	168	140	156	180	196
70	151	139	192	168	213	173	192	232	251
95	182	167	232	201	258	204	230	282	304
120	210	192	269	232	299	231	261	328	352
150	240	219	300	258	344	261	293	379	406
185	273	248	341	294	392	292	331	434	463
240	321	291	400	344	461	336	382	514	546
300	367	334	458	394	530	379	427	593	629
400	–	–	–	–	–	–	–	–	754
500	–	–	–	–	–	–	–	–	868
630	–	–	–	–	–	–	–	–	1005

Three Loaded Conductors

Size (mm^2)	Current Rating for 3 x PVC Insulated Copper Conductors											
	Reference Installation Method											
	A1	A2	B1	B2	C	D1	D2	E	F		G	
									Trefoil	Laid Flat	Horizontal	Vertical
1.5	13.5	13	15.5	15	17.5	18	19	18.5	–	–	–	–
2.5	18	17.5	21	20	24	24	24	25	–	–	–	–
4	24	23	28	27	32	30	33	34	–	–	–	–
6	31	29	36	34	41	38	41	43	–	–	–	–
10	42	39	50	46	57	50	54	60	–	–	–	–
16	56	52	68	62	76	64	70	80	–	–	–	–
25	73	68	89	80	96	82	92	101	110	114	146	130
35	89	83	110	99	119	98	110	126	137	143	181	162
50	108	99	134	118	144	116	130	153	167	174	219	197
70	136	125	171	149	184	143	162	196	216	225	281	254
95	164	150	207	179	223	169	193	238	264	275	341	311
120	188	172	239	206	259	192	220	276	308	321	396	362
150	216	196	262	225	299	217	246	319	356	372	456	419
185	245	223	296	255	341	243	278	364	409	427	521	480
240	286	261	346	297	403	280	320	430	485	507	615	569
300	328	298	394	339	464	316	359	497	561	587	709	659
400	–	–	–	–	–	–	–	–	656	689	852	795
500	–	–	–	–	–	–	–	–	749	789	982	920
630	–	–	–	–	–	–	–	–	855	905	1138	1070

EPR/XLPE Current Ratings (Copper)

Current ratings are based on values given in IEC 60364-5-52 (2009), with a reference conductor temperature of 70^{o}C, ambient temperature of 30^{o}C and soil temperature of 20^{o}C.

Two Loaded Conductors

Size (mm^2)	Current Rating for 2 x EPR or XLPE Insulated Copper Conductors								
	Reference Installation Method								
	A1	A2	B1	B2	C	D1	D2	E	F
1.5	19	18.5	23	22	24	25	27	26	–
2.5	26	25	31	30	33	33	35	36	–
4	35	33	42	40	45	43	46	49	–
6	45	42	54	51	58	53	58	63	–
10	61	57	75	69	80	71	77	86	–
16	81	76	100	91	107	91	100	115	–
25	106	99	133	119	138	116	129	149	161
35	131	121	164	146	171	139	155	185	200
50	158	145	198	175	209	164	183	225	242
70	200	183	253	221	269	203	225	289	310
95	241	220	306	265	328	239	270	352	377
120	278	253	354	305	382	271	306	410	437
150	318	290	393	334	441	306	343	473	504
185	362	329	449	384	506	343	387	542	575
240	424	386	528	459	599	395	448	641	679
300	486	442	603	532	693	446	502	741	783
400	–	–	–	–	–	–	–	–	940
500	–	–	–	–	–	–	–	–	1083
630	–	–	–	–	–	–	–	–	1254

Three Loaded Conductors

Size (mm^2)	Current Rating for 3 x EPR or XLPE Insulated Copper Conductors											
	Reference Installation Method											
	A1	A2	B1	B2	C	D1	D2	E	F		G	
									Trefoil	Laid Flat	Horizontal	Vertical
1.5	17	16.5	20	19.5	22	21	23	23	–	–	–	–
2.5	23	22	28	26	30	28	30	32	–	–	–	–
4	31	30	37	35	40	36	39	42	–	–	–	–
6	40	38	48	44	52	44	49	54	–	–	–	–
10	54	51	66	60	71	58	65	75	–	–	–	–
16	73	68	88	80	96	75	84	100	–	–	–	–
25	95	89	117	105	119	96	107	127	135	141	182	161
35	117	109	144	128	147	115	129	158	169	176	226	201
50	141	130	175	154	179	135	153	192	207	216	275	246
70	179	164	222	194	229	167	188	246	268	279	353	318
95	216	197	269	233	278	197	226	298	328	342	430	389
120	249	227	312	268	322	223	257	346	383	400	500	454
150	285	259	342	300	371	251	287	399	444	464	577	527
185	324	295	384	340	424	281	324	456	510	533	661	605
240	380	346	450	398	500	324	375	538	607	634	781	719
300	435	396	514	455	576	365	419	621	703	736	902	833
400	–	–	–	–	–	–	–	–	823	868	1085	1008
500	–	–	–	–	–	–	–	–	946	998	1253	1169
630	–	–	–	–	–	–	–	–	1088	1151	1454	1362

PVC Current Ratings (Aluminum)

Current ratings are based on values given in IEC 60364-5-52 (2009), with a reference conductor temperature of 70°C, ambient temperature of 30°C and soil temperature of 20°C.

Two Loaded Conductors

Size (mm^2)	Current Rating for 2 x PVC Insulated Aluminum Conductors								
	Reference Installation Method								
	A1	A2	B1	B2	C	D1	D2	E	F
2.5	15	14.5	18.5	17.5	21	22	–	23	–
4	20	19.5	25	24	28	29	–	31	–
6	26	25	32	30	36	36	–	39	–
10	36	33	44	41	49	47	–	54	–
16	48	44	60	54	66	61	63	73	–
25	63	58	79	71	83	77	82	89	98
35	77	71	97	86	103	93	98	111	122
50	93	86	118	104	125	109	117	135	149
70	118	108	150	131	160	135	145	173	192
95	142	130	181	157	195	159	173	210	235
120	164	150	210	181	226	180	200	244	273
150	189	172	234	201	261	204	224	282	316
185	215	195	266	230	298	228	255	322	363
240	252	229	312	269	352	262	298	380	430
300	289	263	358	308	406	296	336	439	497
400	–	–	–	–	–	–	–	–	600
500	–	–	–	–	–	–	–	–	694
630	–	–	–	–	–	–	–	–	808

Three Loaded Conductors

Size (mm^2)	Current Rating for 3 x PVC Insulated Aluminum Conductors											
	Reference Installation Method											
	A1	A2	B1	B2	C	D1	D2	E	F		G	
									Trefoil	Laid Flat	Horizontal	Vertical
2.5	14	13.5	16.5	15.5	18.5	18.5	-	19.5	–	–	–	–
4	18.5	17.5	22	21	25	24	-	26	–	–	–	–
6	24	23	28	27	32	30	-	33	–	–	–	–
10	32	31	39	36	44	39	-	46	–	–	–	–
16	43	41	53	48	59	50	53	61	–	–	–	–
25	57	53	70	62	73	64	69	78	84	87	112	99
35	70	65	86	77	90	77	83	96	105	109	139	124
50	84	78	104	92	110	91	99	117	128	133	169	152
70	107	98	133	116	140	112	122	150	166	173	217	196
95	129	118	161	139	170	132	148	183	203	212	265	241
120	149	135	186	160	197	150	169	212	237	247	308	282
150	170	155	204	176	227	169	189	245	274	287	356	327
185	194	176	230	199	259	190	214	280	315	330	407	376
240	227	207	269	232	305	218	250	330	375	392	482	447
300	261	237	306	265	351	247	282	381	434	455	557	519
400	–	–	–	–	–	–	–	–	526	552	671	629
500	–	–	–	–	–	–	–	–	610	640	775	730
630	–	–	–	–	–	–	–	–	711	746	900	852

EPR/XLPE Current Ratings (Aluminum)

Current ratings are based on values given in IEC 60364-5-52 (2009), with a reference conductor temperature of 70°C, ambient temperature of 30°C and soil temperature of 20°C.

Two Loaded Conductors

Size (mm^2)	Current Rating for 2 x EPR or XLPE Insulated Aluminum Conductors								
	Reference Installation Method								
	A1	A2	B1	B2	C	D1	D2	E	F
2.5	20	19.5	25	23	26	26	–	28	–
4	27	26	33	31	35	33	–	38	–
6	35	33	43	40	45	42	–	49	–
10	48	45	59	54	62	55	–	67	–
16	64	60	79	72	84	71	76	91	–
25	84	78	105	94	101	90	98	108	121
35	103	96	130	115	126	108	117	135	150
50	125	115	157	138	154	128	139	164	184
70	158	145	200	175	198	158	170	211	237
95	191	175	242	210	241	186	204	257	289
120	220	201	281	242	280	211	233	300	337
150	253	230	307	261	324	238	261	346	389
185	288	262	351	300	371	267	296	397	447
240	338	307	412	358	439	307	343	470	530
300	387	352	471	415	508	346	386	543	613
400	–	–	–	–	–	–	–	–	740
500	–	–	–	–	–	–	–	–	856
630	–	–	–	–	–	–	–	–	996

Three Loaded Conductors

Size (mm^2)	Current Rating for 3 x EPR or XLPE Insulated Aluminum Conductors											
	Reference Installation Method											
	A1	A2	B1	B2	C	D1	D2	E	F		G	
									Trefoil	Laid Flat	Horizontal	Vertical
2.5	19	18	22	21	24	22	–	24	–	–	–	–
4	25	24	29	28	32	28	–	32	–	–	–	–
6	32	31	38	35	41	35	–	42	–	–	–	–
10	44	41	52	48	57	46	–	58	–	–	–	–
16	58	55	71	64	76	59	64	77	–	–	–	–
25	76	71	93	84	90	75	82	97	103	107	138	122
35	94	87	116	103	112	90	98	120	129	135	172	153
50	113	104	140	124	136	106	117	146	159	165	210	188
70	142	131	179	156	174	130	144	187	206	215	271	244
95	171	157	217	188	211	154	172	227	253	264	332	300
120	197	180	251	216	245	174	197	263	296	308	387	351
150	226	206	267	240	283	197	220	304	343	358	448	408
185	256	233	300	272	323	220	250	347	395	413	515	470
240	300	273	351	318	382	253	290	409	471	492	611	561
300	344	313	402	364	440	286	326	471	547	571	708	652
400	–	–	–	–	–	–	–	–	633	694	856	792
500	–	–	–	–	–	–	–	–	770	806	991	921
630	–	–	–	–	–	–	–	–	899	942	1154	1077

Temperature Derating Factors

Ambient Temperature

Derating factors for ambient air temperatures other than 30°C

°C	Ambient Temperature Derating Factor	
	PVC	EPR / XLPE
10	1.22	1.15
15	1.17	1.12
20	1.12	1.08
25	1.06	1.04
30	1	1
35	0.94	0.96
40	0.87	0.91
45	0.79	0.87
50	0.71	0.82
55	0.61	0.76
60	0.5	0.71
65	–	0.65
70	–	0.58
75	–	0.5
80	–	0.41
85	–	–
90	–	–
95	–	–

Soil Temperature

Derating factors for soil temperatures other than 20°C

°C	Soil Temperature Derating Factor	
	PVC	**EPR / XLPE**
10	1.1	1.07
15	1.05	1.04
20	1	1
25	0.95	0.96
30	0.89	0.93
35	0.84	0.89
40	0.77	0.85
45	0.71	0.8
50	0.63	0.76
55	0.55	0.71
60	0.45	0.65
65	–	0.6
70	–	0.53
75	–	0.46
80	–	0.38

Grouping Derating Factors

Contents

Above Ground

Single Layer

Installation	Above Ground Grouping on a Single Layer Derating Factor												Reference Method
	Number of Grouped Cables												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**12**	**16**	**20**	
Bunched in air, on a surface, embedded or enclosed	1.0	0.8	0.7	0.65	0.6	0.57	0.54	0.52	0.5	0.45	0.41	0.38	A to F
Single layer on wall, floor or unperforated cable tray systems	1.0	0.85	0.79	0.75	0.73	0.72	0.72	0.71	0.7	0.7	0.7	0.7	C
Single layer fixed directly under a wooden ceiling	0.95	0.81	0.72	0.68	0.66	0.64	0.63	0.62	0.61	0.61	0.61	0.61	C
Single layer on a perforated horizontal or vertical cable tray systems	1.0	0.88	0.82	0.77	0.75	0.73	0.73	0.72	0.72	0.72	0.72	0.72	E, F
Single layer on cable ladder systems or cleats etc.	1.0	0.87	0.82	0.8	0.8	0.79	0.79	0.78	0.78	0.78	0.78	0.78	E, F

Multiple Layers

Installation		No. of Layers	Above Ground Grouping on Multiple Layers Derating Factor											
			No. of Multicore Cables per Layer						No. of Single Core Three-Phase Circuits per Layer					
									Cables Laid Flat			Cables in Trefoil		
			1	2	3	4	6	9	1	2	3	1	2	3
Horizontal perforated cable tray systems (1)	Touching	1	1.0	0.88	0.82	0.79	0.76	0.73	0.98	0.91	0.87	1.0	0.98	0.96
		2	1.0	0.87	0.8	0.77	0.73	0.68	0.96	0.87	0.81	0.97	0.93	0.89
		3	1.0	0.86	0.79	0.76	0.71	0.66	0.95	0.85	0.78	0.96	0.92	0.86
		6	1.0	0.84	0.77	0.73	0.68	0.64	–	–	–	–	–	–
	Spaced (3)	1	1.0	1.0	0.98	0.95	0.91	–	–	–	–	–	–	–
		2	1.0	0.99	0.96	0.92	0.87	–	–	–	–	–	–	–
		3	1.0	0.98	0.95	0.91	0.85	–	–	–	–	–	–	–
Vertical perforated cable tray systems (2)	Touching	1	1.0	0.88	0.82	0.78	0.73	0.72	0.96	0.86	–	1.0	0.91	0.89
		2	1.0	0.88	0.81	0.76	0.71	0.7	0.95	0.84	–	1.0	0.9	0.86
	Spaced (1)	1	1.0	0.91	0.89	0.88	0.87	–	–	–	–	–	–	–
		2	1.0	0.91	0.88	0.87	0.85	–	–	–	–	–	–	–
Horizontal unperforated cable tray systems (1)	Touching	1	0.97	0.84	0.78	0.75	0.71	0.68	–	–	–	–	–	–
		2	0.97	0.83	0.76	0.72	0.68	0.63	–	–	–	–	–	–
		3	0.97	0.82	0.75	0.71	0.66	0.61	–	–	–	–	–	–
		6	0.97	0.81	0.73	0.69	0.63	0.58	–	–	–	–	–	–
Cable ladder systems. Cleats. etc	Touching	1	1.0	0.87	0.82	0.8	0.79	0.78	1	0.97	0.96	1.0	1.0	1.0
		2	1.0	0.86	0.8	0.78	0.76	0.73	0.98	0.93	0.89	0.97	0.95	0.93
		3	1.0	0.85	0.79	0.76	0.73	0.7	0.97	0.9	0.86	0.96	0.94	0.9
		6	1.0	0.84	0.77	0.73	0.68	0.64	–	–	–	–	–	–
	Spaced (1)	1	1.0	1.0	1.0	1.0	1.0	–	–	–	–	–	–	–
		2	1.0	0.99	0.98	0.97	0.96	–	–	–	–	–	–	–
		3	1.0	0.98	0.97	0.96	0.93	–	–	–	–	–	–	–

Notes

(1) Vertical spacing between layers is at least 300mm and there is at least 20mm horizontal clearance between the layer and wall
(2) Horizontal spacing between layers is at least 225mm with layers mounted back to back
(3) Cables are spaced at least one overall cable diameter apart

Below Ground

The below ground grouping factors apply to an installation depth of 0.7m and a soil thermal resistivity of 2.5 K·m/W. If a circuit comprises n parallel conductors per phase, then for the purpose of the derating factor, this circuit shall be considered as n circuits.

Buried Direct

No. of Circuits	Below Ground Grouping (Buried Direct) Derating Factor				
	Cable to Cable Clearance				
	Touching	One OD (1)	0.125m	0.25m	0.5m
2	0.75	0.8	0.85	0.9	0.9
3	0.65	0.7	0.75	0.8	0.85
4	0.6	0.6	0.7	0.75	0.8
5	0.55	0.55	0.65	0.7	0.8
6	0.5	0.55	0.6	0.7	0.8
7	0.45	0.51	0.59	0.67	0.76
8	0.43	0.48	0.57	0.65	0.75
9	0.41	0.46	0.55	0.63	0.74
12	0.36	0.42	0.51	0.59	0.71
16	0.32	0.38	0.47	0.56	0.38
20	0.29	0.35	0.44	0.53	0.66

Note (1): A clearance of one cable overall diameter

Buried in Conduit

No. of Cables	Below Ground Grouping (Buried in Conduit) Derating Factor							
	Conduit to Conduit Clearance (Multicore)				Conduit to Conduit Clearance (Single Core)			
	Touching	0.25m	0.5m	1.0m	Touching	0.25m	0.5m	1.0m
2	0.85	0.9	0.95	0.95	0.8	0.9	0.9	0.95
3	0.75	0.85	0.9	0.95	0.7	0.8	0.85	0.9
4	0.7	0.8	0.85	0.9	0.65	0.75	0.8	0.9
5	0.65	0.8	0.85	0.9	0.6	0.7	0.8	0.9
6	0.6	0.8	0.8	0.9	0.6	0.7	0.8	0.9
7	0.57	0.76	0.8	0.88	0.53	0.66	0.76	0.87
8	0.54	0.74	0.78	0.88	0.5	0.63	0.74	0.87
9	0.52	0.73	0.77	0.87	0.47	0.61	0.73	0.86
10	0.49	0.72	0.76	0.86	0.45	0.59	0.72	0.85
11	0.47	0.7	0.75	0.86	0.43	0.57	0.7	0.85
12	0.45	0.69	0.74	0.85	0.41	0.56	0.69	0.84
13	0.44	0.68	0.73	0.85	0.39	0.54	0.68	0.84
14	0.42	0.68	0.72	0.84	0.37	0.53	0.68	0.83
15	0.41	0.67	0.72	0.84	0.35	0.52	0.67	0.83
16	0.39	0.66	0.71	0.83	0.34	0.51	0.66	0.83
17	0.38	0.65	0.7	0.83	0.33	0.5	0.65	0.82
18	0.37	0.65	0.7	0.83	0.31	0.49	0.65	0.82
19	0.35	0.64	0.69	0.82	0.3	0.48	0.64	0.82
20	0.34	0.63	0.68	0.82	0.29	0.47	0.63	0.81

Soil Thermal Resistivity Derating Factors

Derating factors for installing cables in soil with thermal resistivity other than 2.5 K·m/W

Soil Thermal Resistivity (K·m/W)	Soil Thermal Resistivity Derating Factor	
	Buried Direct	Buried in Conduit
0.5	1.88	1.28
0.7	1.62	1.2
1	1.5	1.18
1.5	1.28	1.1
2	1.12	1.05
2.5	1	1
3	0.9	0.96

AC Reactance

Typical AC reactances for copper and aluminum insulated cables operating at 50Hz are based on values given in AS/NZS 3008.1.

Multicore Cables

Size (mm^2)	AC Reactance (Ω\km)				
	PVC		EPR	XLPE	
	Circular (1)	Shaped (1)		Circular (1)	Shaped (1)
1	0.139	0.119	-	0.114	-
1.5	0.129	0.111	-	0.107	-
2.5	0.118	0.102	-	0.0988	-
4	0.11	0.102	-	0.093	-
6	0.104	0.0967	-	0.0887	-
10	0.0967	0.0906	-	0.084	-
16	0.0913	0.0861	0.0794	0.0805	0.0742
25	0.0895	0.0853	0.0786	0.0808	0.0744
35	0.0863	0.0826	0.0761	0.0786	0.0725
50	0.0829	0.0797	0.0734	0.0751	0.0692
70	0.0798	0.077	0.071	0.0741	0.0683
95	0.079	0.0766	0.0706	0.0725	0.0668
120	0.0765	0.0743	0.0685	0.0713	0.0657
150	0.0765	0.0745	0.0687	0.0718	0.0662
185	0.0762	0.0744	0.0686	0.072	0.0663
240	0.0751	0.0735	0.0678	0.0709	0.0653
300	0.0746	0.0732	0.0675	0.0704	0.0649
400	0.074	0.0728	0.0671	0.0702	0.0647
500	0.0734	0.0723	0.0666	0.07	0.0645

Note (1): Circular or shaped refers to the conductor's cross-sectional shape

Single Core Cables

Size (mm^2)	AC Reactance (Ω\km)					
	PVC		EPR		XLPE	
	Flat (1)	Trefoil	Flat (1)	Trefoil	Flat (1)	Trefoil
1	0.184	0.168	0.194	0.179	0.181	0.166
1.5	0.172	0.157	0.183	0.167	0.17	0.155
2.5	0.159	0.143	0.168	0.153	0.156	0.141
4	0.152	0.137	0.157	0.142	0.146	0.131
6	0.143	0.128	0.148	0.133	0.138	0.123
10	0.134	0.118	0.138	0.123	0.129	0.114
16	0.126	0.111	0.13	0.114	0.122	0.106
25	0.121	0.106	0.125	0.109	0.118	0.102
35	0.117	0.101	0.12	0.104	0.113	0.0982
50	0.111	0.0962	0.114	0.0988	0.108	0.0924
70	0.107	0.0917	0.109	0.0941	0.104	0.0893
95	0.106	0.0904	0.108	0.0924	0.102	0.0868
120	0.102	0.087	0.104	0.0889	0.0996	0.0844
150	0.102	0.0868	0.104	0.0885	0.0996	0.0844
185	0.101	0.0862	0.103	0.0878	0.0988	0.0835
240	0.0999	0.0847	0.101	0.0861	0.097	0.0818
300	0.0991	0.0839	0.1	0.0852	0.0961	0.0809
400	0.0982	0.0829	0.0993	0.0841	0.0955	0.0802
500	0.0973	0.082	0.0983	0.083	0.0948	0.0796
630	0.0952	0.08	0.0961	0.0809	0.094	0.0787

Note (1): Single core cables are laid flat and touching

AC Resistance

Typical AC resistances for copper and aluminum insulated cables operating at 50Hz are based on values given in AS/NZS 3008.1.

Contents

Multicore Cables

Copper Conductors

Note that for tinned copper conductors, a scaling factor of 1.01 should be applied.

Size (mm^2)	AC Resistance (Ω\km) of Multicore Copper Cables								
	Circular Conductors					Shaped Conductors			
	45°C	60°C	75°C	90°C	110°C	45°C	60°C	75°C	90°C
1	23.3	24.5	25.8	27	28.7	-	-	-	-
1.5	14.9	15.7	16.5	17.3	18.4	-	-	-	-
2.5	8.14	8.57	9.01	9.45	10	-	-	-	-
4	5.06	5.33	5.61	5.88	6.24	-	-	-	-
6	3.38	3.56	3.75	3.93	4.17	-	-	-	-
10	2.01	2.12	2.23	2.33	2.48	-	-	-	-
16	1.26	1.33	1.4	1.47	1.56	1.26	1.33	1.4	1.47
25	0.799	0.842	0.884	0.927	0.984	0.799	0.842	0.884	0.927
35	0.576	0.607	0.638	0.669	0.71	0.576	0.607	0.638	0.669

50	0.426	0.449	0.471	0.494	0.524	0.426	0.448	0.471	0.494
70	0.295	0.311	0.327	0.343	0.364	0.295	0.311	0.327	0.342
95	0.214	0.225	0.236	0.248	0.262	0.213	0.224	0.236	0.247
120	0.17	0.179	0.188	0.197	0.209	0.17	0.179	0.187	0.196
150	0.139	0.146	0.153	0.16	0.17	0.138	0.145	0.153	0.16
185	0.112	0.118	0.123	0.129	0.136	0.111	0.117	0.123	0.128
240	0.087	0.0912	0.0955	0.0998	0.105	0.0859	0.0902	0.0945	0.0988
300	0.0712	0.0745	0.0778	0.0812	0.0852	0.0698	0.0732	0.0766	0.08
400	0.058	0.0605	0.063	0.0656	0.0685	0.0563	0.0589	0.0615	0.0641
500	0.0486	0.0506	0.0525	0.0544	0.0565	0.0465	0.0485	0.0508	0.0526

Aluminum Conductors

Size (mm^2)	AC Resistance (Ω\km) of Multicore Aluminum Cables							
	Circular Conductors				Shaped Conductors			
	45°C	60°C	75°C	90°C	45°C	60°C	75°C	90°C
16	2.1	2.22	2.33	2.45	2.1	2.22	2.33	2.45
25	1.32	1.39	1.47	1.54	1.32	1.39	1.47	1.54
35	0.956	1.01	1.06	1.11	0.956	1.01	1.06	1.11
50	0.706	0.745	0.784	0.822	0.706	0.745	0.783	0.822
70	0.488	0.515	0.542	0.569	0.488	0.515	0.542	0.568
95	0.353	0.373	0.392	0.411	0.353	0.372	0.392	0.411
120	0.28	0.295	0.31	0.325	0.279	0.295	0.31	0.325

150	0.228	0.241	0.253	0.265	0.228	0.24	0.253	0.265
185	0.182	0.192	0.202	0.212	0.182	0.192	0.202	0.211
240	0.14	0.148	0.155	0.162	0.139	0.147	0.154	0.162
300	0.113	0.119	0.125	0.131	0.112	0.118	0.124	0.13
400	0.0897	0.0943	0.0988	0.103	0.0886	0.0932	0.0978	0.102
500	0.073	0.0765	0.08	0.0835	0.0716	0.0752	0.0788	0.0824

Single Core Cables

Size (mm^2)	**AC Resistance (Ω\km) of Single Core Cables**								
	Aluminum Conductors				**Copper Conductors (1)**				
	45°C	**60°C**	**75°C**	**90°C**	**45°C**	**60°C**	**75°C**	**90°C**	**110°C**
1	-	-	-	-	23.3	24.5	25.8	27	28.7
1.5	-	-	-	-	14.9	15.7	16.5	17.3	18.4
2.5	-	-	-	-	8.14	8.57	9.01	9.45	10
4	-	-	-	-	5.06	5.33	5.61	5.88	6.24
6	-	-	-	-	3.38	3.56	3.75	3.93	4.17
10	-	-	-	-	2.01	2.12	2.23	2.33	2.48
16	2.1	2.22	2.33	2.45	1.26	1.33	1.4	1.47	1.56
25	1.32	1.39	1.47	1.54	0.799	0.842	0.884	0.927	0.984
35	0.956	1.01	1.06	1.11	0.576	0.607	0.638	0.668	0.71
50	0.706	0.745	0.783	0.822	0.426	0.448	0.471	0.494	0.524

70	0.488	0.515	0.542	0.568	0.295	0.311	0.327	0.342	0.363
95	0.353	0.372	0.392	0.411	0.213	0.225	0.236	0.247	0.262
120	0.279	0.295	0.31	0.325	0.17	0.179	0.188	0.197	0.208
150	0.228	0.24	0.253	0.265	0.138	0.145	0.153	0.16	0.169
185	0.182	0.192	0.202	0.212	0.111	0.117	0.123	0.129	0.136
240	0.14	0.147	0.155	0.162	0.0862	0.0905	0.0948	0.0991	0.105
300	0.113	0.119	0.125	0.13	0.0703	0.0736	0.077	0.0803	0.0846
400	0.089	0.0936	0.0981	0.103	0.0569	0.0595	0.062	0.0646	0.0677
500	0.0709	0.0744	0.0779	0.0813	0.0467	0.0487	0.0506	0.0525	0.0547
630	0.0571	0.0597	0.0623	0.0649	0.0389	0.0404	0.0418	0.0432	0.0448

Note (1): for tinned copper conductors, a scaling factor of 1.01 should be applied.

DC Resistance

Typical DC reactances for copper and aluminum conductors operating at 20^{o}C are based on values given in AS/NZS 1125.1.

Size (mm^2)	Maximum DC Resistance (Ω\km) at 20^{o}C								
	Copper							Aluminum	
	Stranded Conductors				Solid Conductors			Stranded Conductors	Solid Conductors
	Plain	Silver	Tinned	Nickel	Silver	Tinned	Nickel		
0.5	38.4	38.4	39.6		36	36.7	39.6	-	-
0.75	25.3	25.3	26		24.5	24.8	19.7	-	-
1	21.2	21.2	21.6	23.3	18.1	18.2	13.2	-	-
1.5	13.6	13.6	13.8	14.9	12.1	12.2	-	-	-
2.5	7.41	7.41	7.56	8.14	7.41	7.56	-	-	12.1
4	4.61	4.61	4.7	5.06	4.61	4.7	-	7.41	7.54
6	3.08	3.08	3.11	3.34	3.08	3.11	-	4.61	5.01
10	1.83	1.83	1.84	2	1.83	1.84	-	3.08	3.08
16	1.15	1.15	1.16	-	1.15	1.16	-	1.91	1.91
25	0.727	0.727	0.734	-	0.727	-	-	1.2	1.2
35	0.524	0.524	0.529	-	-	-	-	0.868	0.868
50	0.387	0.387	0.391	-	-	-	-	0.641	0.641
70	0.268	0.268	0.27	-	-	-	-	0.443	0.443
95	0.193	0.193	0.195	-	-	-	-	0.32	0.32
120	0.153	0.153	0.154	-	-	-	-	0.253	0.253
150	0.124	0.124	0.126	-	-	-	-	0.206	0.206
185	0.0991	0.0991	0.1	-	-	-	-	0.164	0.164
240	0.0754	0.0754	0.0762	-	-	-	-	0.125	0.125
300	0.0601	0.0601	0.0607	-	-	-	-	0.1	0.1
400	0.047	0.047	0.0475	-	-	-	-	0.0778	-
500 (1)	0.0366 / 0.037332	0.0366 / 0.037332	0.0369 / 0.037638	-	-	-	-	0.0605 / 0.06171	-
630 (1)	0.0283 / 0.028866	0.0283 / 0.028866	0.0286 / 0.029172	-	-	-	-	0.0469 / 0.047838	-

Note (1): resistance values are quoted for single core / Multicore cables

LV Motor Data (IEC)

The following typical low voltage motor characteristics can be used as a quick reference data set when specific information is not available. The data is based on Toshiba TEFC, heavy duty, high efficiency general purpose motors operating at 50Hz.

kW	RPM	Frame Size	Full Load Current (A)			No Load Current at 415V (A)	Locked Rotor Current (% F/L)	Torque (% F/L)			Efficiency (%)			Power Factor (PU)			Rotor GD ($kg.m^2$)	dB(A) at 1m
			At 415V	At 400V	At 380V			Locked Rotor	Pull Up	Break -down	Full Load	75%	50%	Full Load	75%	50%		
0.37	2870	D71M	1	1	0.95	0.7	580	300	290	345	72.7	70.3	64.6	0.75	0.65	0.52	0.002	54
0.37	1405	D71	1.2	1.2	1.2	0.9	458	395	360	385	70	67.6	60.6	0.65	0.56	0.44	0.004	46
0.37	935	D80	1.4	1.5	1.6	0.8	411	370	352	369	65.7	62.6	55.4	0.59	0.49	0.39	0.016	48
0.55	2805	D71	1.3	1.4	1.4	0.7	392	260	149	314	70.1	70.1	66.4	0.87	0.82	0.73	0.002	54
0.55	1410	D80	1.3	1.4	1.4	0.8	600	330	302	345	74.4	73.7	69.3	0.79	0.71	0.58	0.01	48
0.55	935	D80	1.9	1.9	1.9	1.6	474	345	320	330	72.1	69.7	63.5	0.58	0.48	0.37	TBA	50
0.75	2840	D80	1.8	1.8	1.8	1.1	771	414	387	440	76.5	75.3	69.3	0.8	0.71	0.59	0.007	64
0.75	1400	D80	1.8	1.8	1.9	1.1	543	295	280	310	74.5	74.4	70.6	0.8	0.72	0.59	0.011	48
0.75	935	D90S	2	2	2.1	1	490	248	228	258	78	78.4	75.5	0.69	0.6	0.48	0.022	49
0.75	700	100L	2.2	2.3	2.4	2	360	200	164	220	73	72.7	68.7	0.67	0.58	0.47	0.028	47
1.1	2830	D80	2.3	2.4	2.5	1	739	366	292	370	78.1	78	74.4	0.87	0.82	0.71	0.008	64
1.1	1425	D90S	2.5	2.6	2.6	1.4	620	301	245	310	81.4	81.9	79.7	0.77	0.7	0.57	0.019	50
1.1	940	D90L	3	3	3.2	2.1	540	298	276	308	78.9	78.7	75.3	0.66	0.57	0.44	0.028	48
1.1	705	D100L	3.4	3.5	3.7	2.4	440	230	205	230	74.6	73.4	69	0.62	0.53	0.42	0.034	51
1.5	2850	D90S	2.9	3	3.2	0.9	759	312	215	305	84.1	84.8	82.9	0.9	0.87	0.79	0.014	65
1.5	1420	D90L	3.3	3.4	3.5	1.7	636	310	303	340	81.7	82.3	80.4	0.79	0.72	0.59	0.022	50
1.5	940	D100L	3.6	3.6	3.7	2.1	583	295	270	310	81.9	82.3	80	0.73	0.65	0.52	0.052	51
1.5	690	D112M	4.5	4.7	4.9	2.6	420	240	170	230	74.3	74	70.1	0.62	0.53	0.42	0.076	53
2.2	2810	D90L	4	4.2	4.5	1.1	775	345	266	312	85	86.9	86.8	0.91	0.89	0.81	0.016	64
2.2	1415	D100L	4.5	4.6	4.8	2.3	656	288	246	297	82.8	83.6	81.9	0.82	0.75	0.63	0.041	53
2.2	940	D112M	5.2	5.4	5.6	3.5	654	315	280	330	81.6	81.6	78.6	0.71	0.62	0.5	0.07	55
2.2	710	D132S	5.4	5.6	5.9	4.1	520	200	200	250	79.8	79.3	75.8	0.73	0.65	0.52	0.132	57
3	2890	D100L	5.6	5.8	6	1.8	786	225	172	305	85.8	86.9	85.9	0.9	0.88	0.8	0.045	68
3	1420	D100L	6.3	6.4	6.6	3.4	762	390	370	394	85.1	85.5	83.8	0.79	0.72	0.59	0.059	52
3	960	D132S	7	7	7.2	4.6	529	220	212	275	82.2	81.7	78.9	0.73	0.64	0.52	0.123	53
3	710	D132M	7.2	7.5	7.9	5	510	260	250	320	81	80.7	77.7	0.74	0.66	0.53	0.207	58
4	2890	D112M	7.6	7.8	8	2.7	763	240	152	350	85.9	86.5	85.2	0.89	0.86	0.77	0.051	68
4	1420	D112M	7.8	8.1	8.5	3.7	769	310	252	345	85.5	86.3	85.3	0.83	0.77	0.65	0.072	56
4	960	D132M	8.8	9.1	9.5	5.3	591	245	225	290	84.7	84.7	82.6	0.75	0.67	0.54	0.148	54
4	705	D160M	9.6	10	10.5	5.4	480	180	195	280	82	81	79	0.71	0.66	0.59	0.372	57

5.5	2880	D132S	11	11.5	12	4.6	582	220	180	273	86.4	86	83.2	0.8	0.75	0.66	0.064	74
5.5	1440	D132S	11	11.5	12	5	600	254	230	268	86.1	86.3	84.6	0.82	0.77	0.67	0.129	61
5.5	965	D132M	11.5	12	12.5	5.7	678	240	215	252	87.2	87.8	87	0.77	0.7	0.59	0.255	53
5.5	710	D160M	11.9	12.4	13	6.9	500	170	190	260	84.1	84.4	82.5	0.79	0.73	0.61	0.57	60
7.5	2910	D132S	14.2	14.7	15.5	5.6	697	226	185	305	87.6	87.4	85.2	0.84	0.8	0.7	0.087	74
7.5	1445	D132M	14.5	15	15.5	6	648	296	269	318	87.2	87.3	85.1	0.84	0.8	0.7	0.179	61
7.5	960	D160M	17	17	17.5	9.3	565	255	240	305	86.1	86	84	0.74	0.67	0.54	0.575	64
7.5	715	D160L	16.1	16.7	17.6	10	550	180	195	280	83.9	83.7	81.1	0.79	0.73	0.62	0.9	61
11	2925	D160M	20	20.5	21	7.6	725	250	200	305	89.1	88.9	86.8	0.86	0.82	0.73	0.167	77
11	1460	D160M	21	22	23	9.5	714	295	240	330	88.4	87.9	85.7	0.83	0.78	0.67	0.346	67
11	965	D160L	24	24	25	15	600	327	232	336	88.6	88.4	86.4	0.71	0.62	0.5	0.86	66
11	720	D180L	24	24.9	26.2	17	520	230	210	280	87	87	85	0.75	0.7	0.62	1.42	62
15	2920	D160M	27	27.5	28.5	5.7	715	255	208	318	89.4	89.3	87.6	0.88	0.85	0.78	0.215	78
15	1455	D160L	27.5	28	29.5	11.1	727	295	225	315	89.5	89.6	88	0.86	0.81	0.72	0.485	68
15	975	D180L	29	30	31	21.1	638	216	175	265	88.5	88.9	88.1	0.82	0.77	0.67	1.53	66
15	730	D200L	30	31.4	32.8	18.9	530	195	180	240	89.4	89.8	88.4	0.78	0.74	0.62	1.84	65
18.5	2925	D160L	32	33	34	8.7	813	318	226	355	91.6	91.7	90.6	0.9	0.87	0.81	0.259	77
18.5	1465	D180M	34	35	37	10.4	676	242	196	258	90.3	91.2	90.8	0.87	0.84	0.77	0.676	75
18.5	975	D200L	37.5	38	38	17.8	688	225	220	310	89.9	90.1	89	0.79	0.73	0.61	1.133	70
18.5	735	D225S	35.4	36.7	38.7	23.3	460	184	148	214	91.7	91.7	91.2	0.79	0.76	0.67	2.515	64
22	2945	D180M	39	40	42	12.4	833	290	230	360	90.7	90.2	87.5	0.87	0.84	0.76	0.504	84
22	1460	D180L	40	41	43	12.7	725	255	208	272	90.3	90.7	89.7	0.87	0.84	0.76	0.856	76
22	970	D200L	42	43	45	16	643	230	200	270	90.4	91.1	90.8	0.83	0.79	0.69	1.333	71
22	735	D225M	45.2	45.8	48.2	28.5	510	230	205	250	91.6	91.8	88.9	0.75	0.71	0.62	3.02	66
30	2945	D200L	52	54	56	13.1	748	242	167	315	91.5	91.2	89.5	0.88	0.87	0.82	0.758	88
30	1460	D200L	52	54	57	14.5	708	250	179	273	91.6	92.4	92.3	0.88	0.85	0.79	1.09	77
30	975	D225M	55	58	60	19.9	682	223	144	242	91.4	91.9	91.4	0.84	0.8	0.71	2.16	71
30	736	D250S	61	63	67	32	585	210	180	230	91	90.6	89.2	0.75	0.69	0.66	4	70
37	2940	D200L	62.5	65	68	15.5	744	250	185	295	92.3	92.3	91.2	0.89	0.88	0.83	0.902	85
37	1470	D225S	65	67	70.5	21	715	265	195	288	92.3	92.6	91.9	0.86	0.83	0.76	1.682	79
37	980	D250S	67	69	72.5	25.7	627	255	190	285	91.5	92.2	91.8	0.85	0.81	0.72	3.18	74
37	735	D250M	70	73	77	39	560	210	160	210	92.2	92	91.2	0.8	0.76	0.66	4.7	72
45	2950	D225M	76	79	82	19.1	750	274	194	296	92.9	92.7	91.2	0.9	0.88	0.83	1.18	83
45	1470	D225M	80	82	86	25.5	731	262	194	315	92.6	92.9	92.4	0.86	0.82	0.75	2	80
45	980	D250M	82	84	88	34	645	258	182	305	92.3	92.6	92	0.83	0.79	0.69	3.6	74
45	730	D280S	87	90	95	54	560	170	160	230	92.1	92.1	90.8	0.81	0.76	0.66	7.1	72
55	2950	D250S	91	95	99	20.5	791	235	207	320	93.3	93.2	91.5	0.91	0.9	0.85	2.32	88
55	1475	D250S	99	100	105	35.1	833	280	183	350	93.2	93.3	92.6	0.83	0.81	0.72	2.95	83

55	980	D280S	100	103	108	42.8	715	295	207	315	92.7	92.8	91.9	0.83	0.78	0.68	7.45	76
55	730	D280M	104	108	114	62	560	170	155	240	92	91.8	90.1	0.81	0.74	0.67	9.8	74
75	2955	D250M	125	129	135	23.9	824	273	236	385	93.9	93.8	92.2	0.89	0.87	0.81	2.67	86
75	1475	D250M	134	137	141	50.3	705	232	202	305	93.5	93.7	93	0.84	0.79	0.7	4.12	81
75	985	D280M	132	136	142	51.2	659	270	203	302	93.5	93.8	92.9	0.85	0.81	0.71	9.42	76
75	730	D315S	138	143	151	86.9	610	185	165	230	92.1	92	91.1	0.82	0.76	0.69	18.4	74
90	2955	D280S	154	158	165	44.5	692	235	188	315	94.3	94.3	93.4	0.87	0.84	0.77	4.65	83
90	1470	D280S	150	156	164	42.8	763	260	202	296	94.4	94.6	93.9	0.89	0.86	0.81	6.86	87
90	987	D315S	156	156	156	52.2	510	150	134	230	94.4	94.5	93.9	0.86	0.83	0.75	12.6	75
90	730	D315M	165	171	181	98	610	160	150	240	93	92.4	91.7	0.82	0.76	0.68	23.2	74
110	2970	D280M	194	196	201	71.1	773	269	220	322	95.1	95	94	0.83	0.79	0.7	5.92	85
110	1470	D280M	184	189	198	54.9	796	250	180	298	94.7	94.9	94.3	0.88	0.86	0.79	8.23	87
110	986	D315M	196	203	214	71	588	188	160	260	95	95.1	94.5	0.85	0.82	0.73	15.1	75
110	730	D315M	197	205	215	110	615	155	140	230	93.8	93.6	92.8	0.83	0.78	0.69	26	74
132	2955	D315S	220	220	240	46.3	625	222	188	285	95	95.1	94.2	0.92	0.91	0.87	9.05	83
132	1485	D315S	227	231	239	79.8	758	210	178	290	95.3	95.2	94.6	0.85	0.82	0.73	15.2	83
132	2965	D315M	240	249	263	41	629	156	123	275	95.5	95.7	95.3	0.92	0.91	0.87	10.3	85
150	1480	D315M	246	255	269	58.5	587	232	197	237	95	95.1	93.8	0.9	0.89	0.84	17.5	82.5
150	980	D315M	260	273	287	101	692	208	166	275	95	95.2	94.9	0.84	0.8	0.71	20	81

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Adiabatic Short Circuit Temperature Rise

Adiabatic short circuit temperature rise normally refers to the temperature rise in a cable due to a short circuit current. During a short circuit, a high amount of current can flow through a cable for a short time. This surge in current flow causes a temperature rise within the cable.

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Derivation

An "adiabatic" process is a thermodynamic process in which there is no heat transfer. In the context of cables experiencing a short circuit, this means that the energy from the short circuit current contributes only to raising the temperature of the cable conductor (e.g. copper) without any heat loss through the cable (i.e. through resistive effects). This is obviously a simplifying assumption as in reality, there would be heat lost during a short circuit, but it is a conservative one and yields a theoretical temperature rise higher than that found in practice.

The derivation of the short circuit temperature rise is based on a simple application of specific heat capacity. The specific heat capacity of a body (for instance the solid conductor in a cable) is the amount of energy required to change the temperature of the body, and is given by the following basic formula:

$$c_p = \frac{E}{m \Delta T}$$

Where E is the energy dissipated by the body (in Joules), m is the mass of the body (in grams), and ΔT is the change in temperature (in Kelvins).

The energy from a current flowing through a cable is based on the SI definition for electrical energy:

$$E = QV = i^2 Rt$$

Where i is the current (in Amps), R is the resistance of the body which the current is flowing through (in Ω) and t is the duration of the current flow (in seconds).

The mass and resistance of an arbitrary conductive body is proportional to the dimensions of the body and can be described in general terms by the following pair of equations:

$$m = \rho_d A l$$

$$R = \frac{\rho_r l}{A}$$

Where ρ_d is the density of the body (in g mm^{-3}), ρ_r is the resistivity of the body (in Ω mm), A is the cross-sectional area of the body (in mm^2) and l is the length of the body (in mm)

Putting all of these equations together and re-arranging, we get the final result for adiabatic short circuit temperature rise:

$$\Delta T = \frac{i^2 t \rho_r}{A^2 c_p \rho_d}$$

Alternatively, we can re-write this to find the cable conductor cross-sectional area required to dissipate a short circuit current for a given temperature rise is:

$$A = \frac{\sqrt{i^2 t}}{k}$$

With the constant term $k = \sqrt{\frac{c_p \rho_d \Delta T}{\rho_r}}$

Where A is the minimum cross-sectional area of the cable conductor (mm^2)

$i^2 t$ is the energy of the short circuit ($A^2 s$)

c_p is the specific heat capacity of the cable conductor ($J\ g^{-1} K^{-1}$)

ρ_d is the density of the cable conductor material ($g\ mm_{-3}$)

ρ_r is the resistivity of the cable conductor material (Ω mm)

ΔT is the maximum temperature rise allowed (°K)

In practice, it is common to use an $i^2 t$ value that corresponds to the let-through energy of the cable's upstream protective device (i.e. circuit breaker or fuse). The manufacturer of the protective device will provide let-through energies for different prospective fault currents.

Worked Example

This example is illustrative and is only intended to show how the equations derived above are applied. In practice, the IEC method outlined below should be used.

Suppose a short circuit with let-through energy of $1.6x10^7$ occurs on a cable with a copper conductor and PVC insulation. Prior to the short circuit, the cable was operating a temperature of 75°C. The temperature limit for PVC insulation is 160°C and therefore the maximum temperature rise is 85°K.

The specific heat capacity of copper at 25°C is c_p = 0.385 $J\ g^{-1} K^{-1}$. The density of copper is ρ_d = 0.00894 $g\ mm^{-3}$ and the resistivity of copper at 75°C is ρ_r = 0.0000204 Ω mm.

The constant is calculated as k = 119.74. The minimum cable conductor cross-sectional area is calculated as 33.4 mm^2. It should be stressed that the calculated value of k is probably inaccurate because the specific heat capacity of copper is subject to change at different temperatures.

Effects of Short Circuit Temperature Rise

High temperatures can trigger unwanted reactions in the cable insulation, sheath materials and other components, which can prematurely degrade the condition of the cable. Cables with larger cross-sectional areas are less sensitive to short circuit temperature rises as the larger amount of conductor material prevents excessive temperature rises.

The maximum allowable short circuit temperature rise depends on the type of insulation (and other materials) used in the construction of the cable. The cable manufacturer will provide specific details on the maximum temperature of the cable for different types of insulation materials, but typically, the maximum temperatures are 160°C for PVC and 250°C for EPR and XLPE insulated cables.

Treatment by International Standards

IEC 60364 (Low voltage electrical installations) contains guidance on the sizing of cables with respect to adiabatic short circuit temperature rise. The minimum cable conductor cross-sectional area is given by IEC 60364-5-54 Clause 543.1.2:

$$A = \frac{\sqrt{i^2 t}}{k}$$

Where A is the minimum cross-sectional area of the cable conductor (mm^2)

$i^2 t$ is the energy of the short circuit ($A^2 s$)

k is a constant that can be calculated from IEC 60364-5-54 Annex A. For example, for copper conductors:

$$k = 226 \sqrt{\ln \left(1 + \frac{\theta_f - \theta_i}{234.5 + \theta_i} \right)}$$

Where θ_i and θ_f are the initial and final conductor temperatures respectively.

The National Electricity Code (NEC) does not have any specific provisions for short circuit temperature rise.

Arc Fault

Contents

Arc Fault Hazards

An arc fault is an electrical discharge between two or more conductors, where the insulating atmosphere (air or gas) has been broken down by the electric field between the conductors. Whenever there is an arc fault, the gases and vapors that make up the atmosphere between the conductors become ionized.

The magnitude of an arc fault is highly variable. The instantaneous arc fault current may be high, approaching the bolted short circuit current, or reasonably low, comparable to the load current. An arc will continue until it becomes unstable and extinguishes itself or until it is interrupted by a protection device (i.e. fuse or circuit breaker).

Arc fault explosion on a 480V switchboard with 23kA upstream fault capacity

Arc faults are characterized by extreme temperatures that can cause severe burns depending on the distance of the operator to the arc. Neal et al [1] in Table IV determined that a 600V, 40kA arc fault with duration of 0.5s has enough energy to cause second-degree burns at a distance of 77 inches (1.96m).

Additionally, arc faults tend to melt terminals that can potentially shower the immediate vicinity with molten metal. The extreme temperatures produced by an arc fault can also lead to fires, causing major damage to equipment.

Damage caused by arc faults

Annex C of IEEE Std 1584 [2] outlines case histories of real life arc fault incidents. The majority of incidents occurred during energisation and switching operations or lives electrical installation work. The potential causes of arc faults include contamination / pollution ingress, equipment failure, rodents / vermin and accidental contact with tools.

Arc Fault Mitigation in Switchgear

Annex ZC6 of AS 3439.1 [3] provides guidelines for the minimization, detection and containment of internal arc faults in switchgear. These are summarized below:

- Insulation of live conductors (in addition to clearances in air)
- Arrangement of busbar sand functional units in separate vented compartments, for more rapid extinguishing of the arc and to contain an arc fault in a single compartment
- Use of protection devices to limit magnitude and duration of arcing current
- Use of devices sensitive to energy radiated from an arc to initiate protection and interrupt arcing current
- Use of earth current detection devices for interruption of arc faults to earth
- Combinations of the above

It should be noted that uncontained arc faults can spread to other parts of the switchboard and develop into larger faults (e.g. functional unit arc fault spreading to busbars).

Arc Fault PPE

Typical arc flash suit

As a general guideline, Neal et al [1] recommends the following personal protection equipment to safeguard against arc faults:

- Clothing consisting of outer layer(s) of loose fitting flame-resistant fabric without openings and inner layers of non-melt able fibers
- Switchman’s hood or face shield with 0.08 inch thick polycarbonate viewing window
- Heavy duty flame-resistant work gloves
- Heavy duty work boots

Annex C of IEEE Std 1584 [2] illustrates a case study (No. 42) of a 2.3kV switching operation that ultimately ended in an arc fault. The operator was wearing a full arc flash suit, safety glasses and fire resistant shirt and pants. The PPE prevented any burn injuries from the arc flash. Other case studies where the operators were not wearing appropriate PPE resulted in severe burns or death.

Arc flash PPE is normally rated to an Arc Thermal Performance exposure Value (ATPV), which specifies the maximum incident arc fault energy that can protect the wearer (measured in calories per cm^2).

By way of example, the results of an arc flash hazard calculation based on IEEE Std 1584 follows to determine the appropriate ATPV rating of PPE. The prospective fault current used was 25kA. A fault clearing time of 0.5s was chosen, which is suitably onerous for a worst-case incident.

The calculation concluded that to protect against injury from an arc fault of this magnitude, PPE with an ATPV rating of over 50 cal/cm^2) is required. The ATPV rating is typically quoted on commonly available arc flash PPE.

Typical arc fault PPE is available from vendors such as Oberon.

References

1. Neal, T., Bingham, A., Doughty, R.L, "Protec ve Clothing for Electric Arc Exposure", IEEE, July / Aug 1997
2. IEEE Std 1584, "Arc Flash Hazard Calcula ons", 2002
3. AS 3439.1, "Low-voltage switchgear and control gear assemblies – Part 1: Type-tested and partially type tested assemblies", 2002

Cable Color Code

Power cable insulation is normally colour coded so that phase, neutral and earth conductors can be easily identified. These colour codes vary with region and / or country:

Country / Region	Three Phase				Single Phase		DC		Protective Earth	Code Reference
	Phase A	Phase B	Phase C	Neutral	Active	Neutral	Positive	Negative		
European Union	Brown	Black	Purple [1]	Light Blue	Black or Brown	Light Blue	- [2]	- [2]	Green / Yellow (with blue markings at ends) [3]	IEC 60445 (2010) [4]
United States	Black or Brown	Red, Orange (delta) or Violet (wyes)	Blue or Yellow	White or Grey	Black (120V), Red (208V) or Blue (240V)	White or Grey	-	-	Green or Green / Yellow	NFPA 70 (NEC) [5]
Australian / New Zealand	Red [6]	White [6]	Dark Blue [6]	Black [6]	Red	Black	Red	Black	Green / Yellow	AS/NZS 3000 (2007)
People's Republic of China	Yellow	Green	Red	Light Blue	-	Light Blue	-	-	Green / Yellow	GB 50303 (2002)
Canada and Japan	Brown	Black	Purple	White or Natural Grey	Black or Brown	Light Blue	- [2]	- [2]	Green or Green / Yellow	IEC 60445 (2010) [4]
Russia	Brown	Black	Purple	Blue	Brown	Blue	Brown	Grey	Green / Yellow	IEC 60445 (2010) [4]

Notes

(1) In the UK, grey can be also be used

(2) No recommenda ons given

(3) In Denmark, Italy and Poland, light blue along the en re length with green / yellow markings at the ends

(4) In 2007, IEC 60446 was merged with IEC 60445 (2010), "Basic and safety principles for man-machine interface, marking and identification – Identification of equipment terminals, conductor terminations and conductors". IEC 60446 is no longer used.

(5) Since 1975, NFPA 70, "The Na onal Electricity Code (NEC)" has not prescribed colors for active conductors (except for orange for earthed delta). Local regulations take precedence.

(6) These are preferred colors. Ac ve conductors can be any colour except for green / yellow, green, yellow, black or light blue

Cable Conductor Materials

In order to transmit electrical current with as few losses as possible, a cable conductor needs to be of low resistivity (or high conductivity). There are two main cable conductor materials used in practice, copper and aluminum, because of their low resistivity characteristics, coupled with their relatively low cost. Silver has better resistivity characteristics than either copper or aluminum, but being a precious metal, is far too costly.

Copper

The resistivity of [copper] is in the order of 1.7 - 1.8 $\times 10^{-6}$ $\Omega mm^2 / m$. Copper is a denser material than aluminum and has a higher melting point, hence has better performance under short circuit conditions and is mechanically stronger. However the high density of copper makes it less flexible than aluminum. Copper conductors also need to be very pure, and small traces of impurities (e.g. phosphorous) can significantly affect conductivity.

Copper is typically used more commonly in industrial plants, generating stations and portable equipment because of its mechanical properties. Furthermore, it is used in applications where space restrictions abound, e.g. offshore platforms and aircraft

Aluminum

The resistivity of [aluminum] is around 2.8 $\times 10^{-6}$ $\Omega mm^2 / m$, which makes it roughly 60% less conductive than copper. Therefore, aluminum conductors need to be oversized by a factor of 1.6 in order to have the equivalent resistance of copper conductors. However aluminum is also 50% lighter in mass than copper so it has a weight advantage. Additionally, it is more malleable and flexible than copper.

Aluminum is inherently corrosion resistant due to the thin oxide layer that is formed when aluminum is exposed to the air. Aluminum also performs better than copper in sulfur laden environments (in terms of corrosion resistance).

Aluminum is typically used for overhead aerial lines because of its light weight and high conductivity. It is also used in applications where space restrictions are not a large factor, e.g. underground cables

Summary

The table below summarizes the pros and cons of copper and aluminum as conductor materials:

	Copper	**Aluminum**
Advantages	• High conductivity • High mechanical strength • Good short circuit performance	• Lower weight • Flexible and malleable • Corrosion resistant
Disadvantages	• Heavier and less flexible • Impurities have large effects on conductivity	• Lower conductivity than copper • Low mechanical strength

Cable Construction

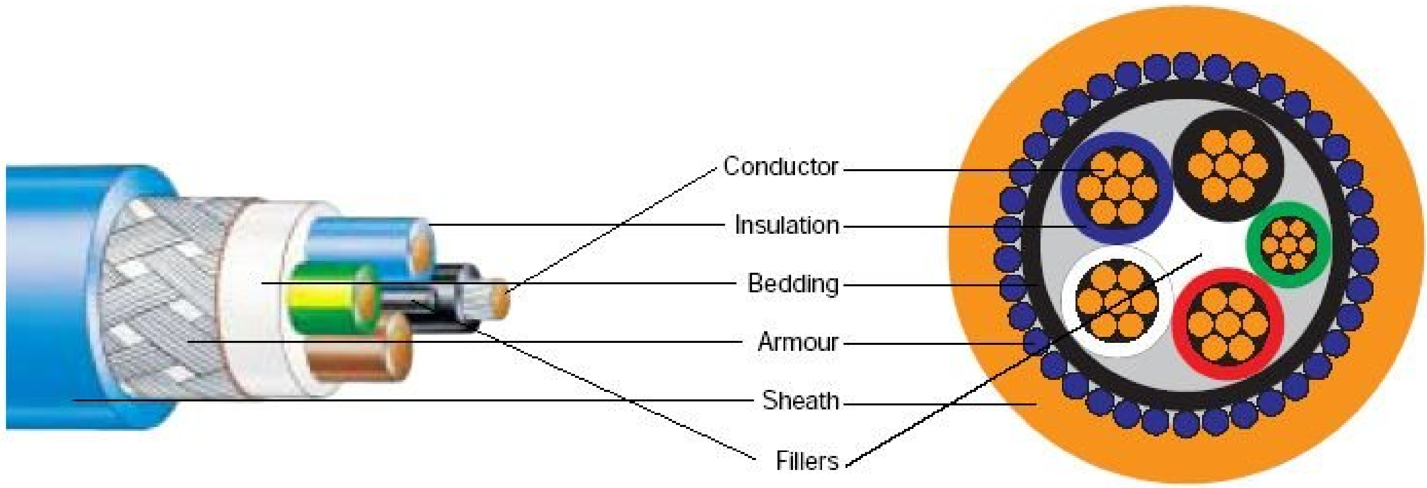
Contents

Introduction

This article gives a brief exposition on the construction of typical low voltage, medium / high voltage and instrumentation cables. The focus is on thermoplastic and thermosetting insulated cables, however the construction of other cables are similar. Although there is more than one way to construct a cable and no one standard to which all vendors will adhere, most cables tend to have common characteristics.

Low Voltage Power and Control Cables

Low voltage power and control cables pertain to electrical cables that typically have a voltage grade of 0.6/1kV or below.



Conductor

Usually stranded copper or aluminum, Copper is denser and heavier, but more conductive than aluminum. Electrically equivalent aluminum conductors have a cross-sectional area approximately 1.6 times larger than copper, but are half the weight (which may save on material cost).

Annealing – is the process of gradually heating and cooling the conductor material to make it more malleable and less brittle.

Coating – surface coating (e.g. tin, nickel, silver, lead alloy) of copper conductors is common to prevent the insulation from attacking or adhering to the copper conductor and prevents deterioration of copper at high temperatures. Tin coatings were used in the past to protect against corrosion from rubber insulation, which contained traces of the sulfur used in the vulcanizing process.

Insulation

Commonly thermoplastic (e.g. PVC) or thermosetting (e.g. EPR, XLPE) type materials, Mineral insulation is sometimes used, but the construction of MI cables is entirely different to normal plastic / rubber insulated cables.

Filler

The interstice of the insulated conductor bundle is sometimes filled, usually with a soft polymer material.

Termite Protection

For underground cables, a nylon jacket can be applied for termite protection, although sometimes a phosphor bronze tape is used.

Bedding / Inner Sheath

Typically a thermoplastic (e.g. PVC) or thermosetting (e.g. CSP) compound, the inner sheath is there to keep the bundle together and to provide a bedding for the cable armour.

Armour

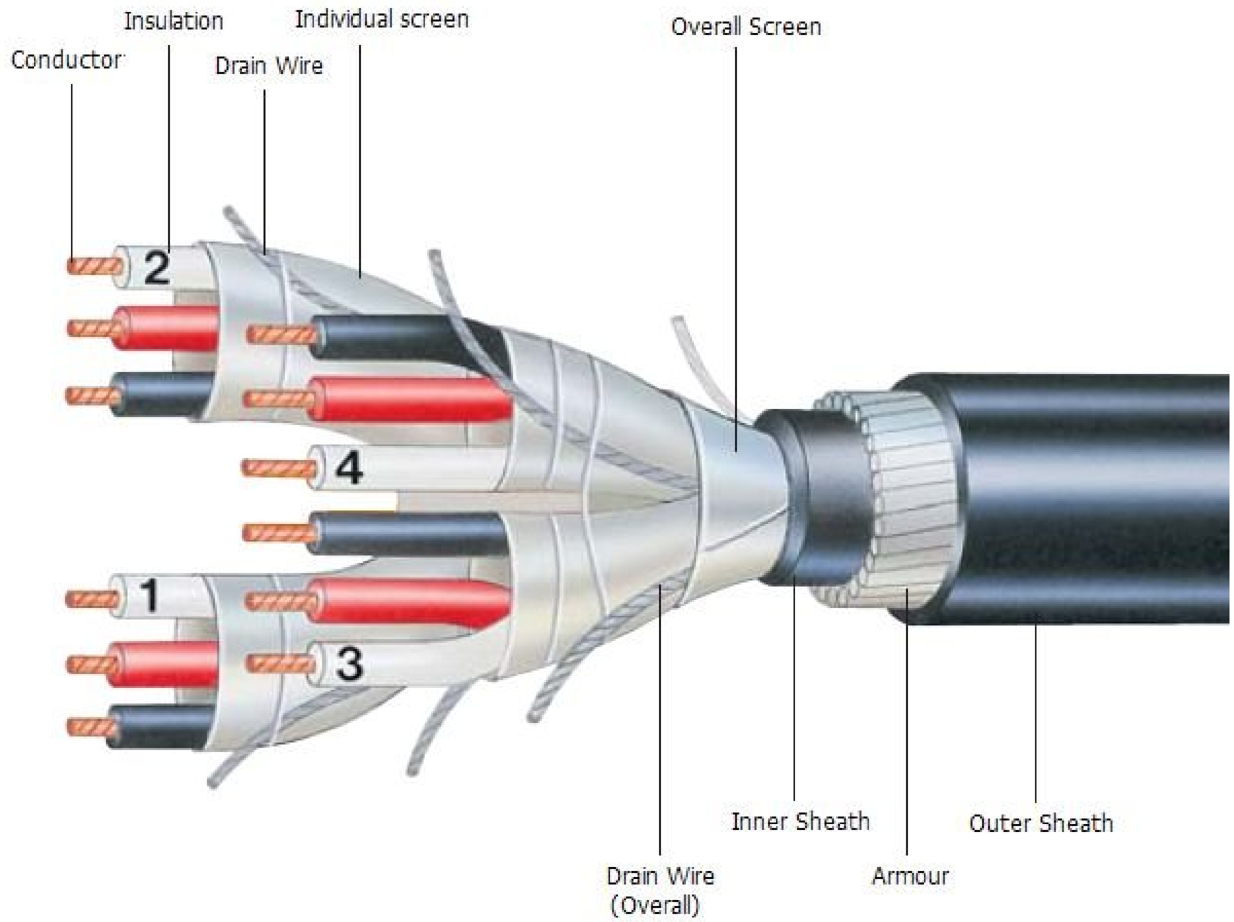
For mechanical protection of the conductor bundle, Steel wire armour or braid (Tape) is typically used. Tinning or galvanizing is used for rust prevention.

Outer Sheath

Applied over the armour for overall mechanical, weather, chemical and electrical protection, Typically a thermoplastic (e.g. PVC) or thermosetting (e.g. CSP) compound, and often the same material as the bedding, Outer sheath is normally colour coded to differentiate between LV, HV and instrumentation cables. Manufacturer's markings and length markings are also printed on the outer sheath.

Low Voltage Instrumentation Cables

Low voltage instrumentation cables pertain to cables for use in instrument applications and typically have a voltage grade of 450/750V or below.



Conductor

Usually stranded copper or Aluminum, Copper is denser and heavier, but more conductive than Aluminum. Electrically equivalent Aluminum conductors have a cross-sectional area approximately 1.6 times larger than copper, but are half the weight (which may save on material cost).

Annealing – is the process of gradually heating and cooling the conductor material to make it more malleable and less brittle.

Coating – surface coating (e.g.. tin, nickel, silver, lead alloy) of copper conductors is common to prevent the insulation from attacking or adhering to the copper conductor and prevents deterioration of copper at high temperatures. Tin coatings were used in the past to protect against corrosion from rubber insulation, which contained traces of the sulfur used in the vulcanizing process.

Insulation

Commonly thermoplastic (e.g. PVC) or thermosetting (e.g. EPR, XLPE) type materials are used. Insulated conductors are bundled in groups (e.g. pairs, triples, quads, etc).

Individual Screen

An individual screen is occasionally applied over each insulated conductor bundle for shielding against noise / radiation and interference from other conductor bundles. Screens are usually a metallic (copper, Aluminum) or semi-metallic (PETP/Al) tape or braid.

Drain Wire

Each screen has an associated drain wire, which assists in the termination of the screen.

Overall Screen

An overall screen is applied over all the insulated conductor bundles for shielding against noise / radiation, interference from other cables and surge / lightning protection. Screens are usually a metallic (copper, Aluminum) or semi-metallic (PETP/Al) tape or braid.

Termite Protection

For underground cables, a nylon jacket can be applied for termite protection, although sometimes a phosphor bronze tape is used.

Bedding / Inner Sheath

Typically a thermoplastic (e.g. PVC) or thermosetting (e.g. CSP) compound, the inner sheath is there to keep the bundle together and to provide bedding for the cable armour.

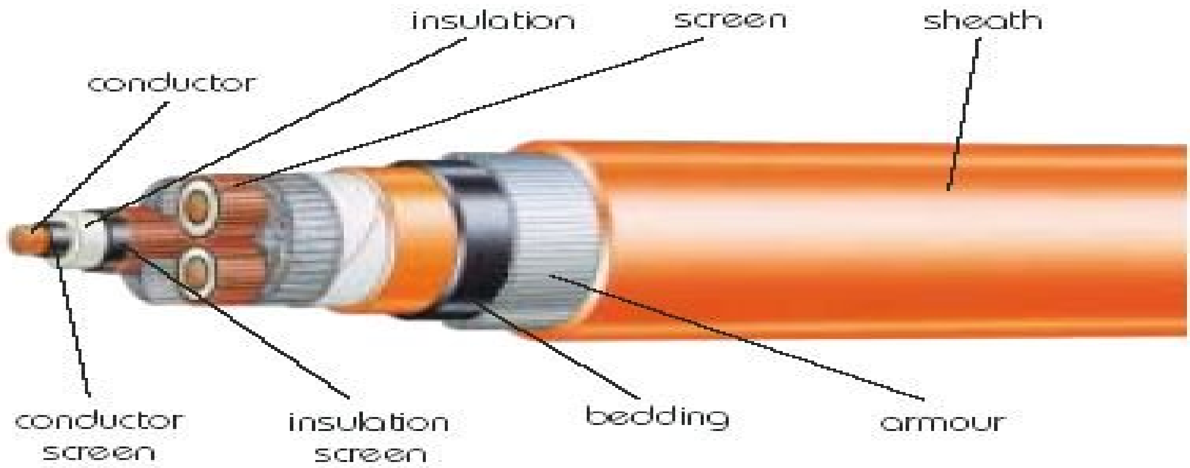
Armour

For mechanical protection of the conductor bundle, Steel wire armour or braid (Tape) is typically used. Tinning or galvanizing is used for rust prevention. Phosphor bronze or tinned copper braid is also used when steel armour is not allowed.

Outer Sheath

Applied over the armour for overall mechanical, weather, chemical and electrical protection, typically a thermoplastic (e.g. PVC) or thermosetting (e.g. CSP) compound, and often the same material as the bedding. Outer sheath is normally colour coded to differentiate between LV, HV and instrumentation cables. Manufacturer’s markings and length markings are also printed on the outer sheath.

Medium / High Voltage Power Cables



Conductor

Usually stranded copper or Aluminum, Copper is denser and heavier, but more conductive than Aluminum. Electrically equivalent Aluminum conductors have a cross-sectional area approximately 1.6 times larger than copper, but are half the weight (which may save on material cost).

Annealing – is the process of gradually heating and cooling the conductor material to make it more malleable and less brittle.

Coating – surface coating (e.g.. tin, nickel, silver, lead alloy) of copper conductors is common to prevent the insulation from attacking or adhering to the copper conductor and prevents deterioration of copper at high temperatures. Tin coatings were used in the past to protect against corrosion from rubber insulation, which contained traces of the sulfur used in the vulcanizing process.

Conductor Screen

A semi-conducting tape to maintain a uniform electric field and minimize electrostatic stresses

Insulation

Typically a thermosetting (e.g.. EPR, XLPE) or paper/lead insulation for cables under 22kV.

Paper-based insulation in combination with oil or gas-filled cables is generally used for higher voltages.

Insulation Screen

A semi-conducting material that has a similar function as the conductor screen (ie. control of the electric field).

Conductor Sheath

A conductive sheath / shield, typically of copper tape or sometimes lead alloy, is used as a shield to keep electromagnetic radiation in, and also provide a path for fault and leakage currents (sheaths are earthed at one cable end). Lead sheaths are heavier and potentially more difficult to terminate than copper tape, but generally provide better earth fault capacity.

Filler

The interstice of the insulated conductor bundle is sometimes filled, usually with a soft polymer material.

Termite Protection

For underground cables, a nylon jacket can be applied for termite protection, although sometimes a phosphor bronze tape is used.

Bedding / Inner Sheath

Typically a thermoplastic (e.g. PVC) or thermosetting (e.g. CSP) compound, the inner sheath is there to keep the bundle together and to provide a bedding for the cable armour.

Armour

For mechanical protection of the conductor bundle, Steel wire armour or braid (Tabe) is typically used. Tinning or galvanizing is used for rust prevention. Phosphor bronze or tinned copper braid is also used when steel armour is not allowed.

Outer Sheath

Applied over the armour for overall mechanical, weather, chemical and electrical protection, typically a thermoplastic (e.g. PVC) or thermosetting (e.g. CSP) compound, and often the same material as the bedding. Outer sheath is normally colour coded to differentiate between LV, HV and instrumentation cables. Manufacturer’s markings and length markings are also printed on the outer sheath.

Cable Impedance Calculations

This article provides details on the calculation of cable impedances - dc resistance, ac resistance and inductive reactance.

Contents

Cable Resistance

The dc and ac resistance of cable conductors can be calculated based on IEC 60287-1 Clause 2.1.

DC Resistance

The dc resistance of cable conductors is calculated as follows:

$$R_{dc} = \frac{1.02 \times 10^6 \times \rho_{20}}{S} \left[1 + \alpha_{20}(\theta - 20)\right]$$

Where R_{dc} is the dc resistance at the conductor operating temperature θ (Ω / *km*)

ρ_{20} is the resis vity of the conductor material at 20°C (Ω.*km*).

- For copper conductors, ρ_{20} = 1.7241 x 10^{-5}
- For aluminum conductors, ρ_{20} = 2.8264 x 10^{-5}

S is the cross-sectional area of the conductor (mm^2)

α_{20} is the temperature coefficient of the conductor material per K at 20°C.

- For copper conductors, α_{20} = 3.93 x 10^{-3}
- For aluminum conductors, α_{20} = 4.03 x 10^{-3}

θ is the conductor operating temperature (°C)

AC Resistance

The ac resistance of cable conductors is the dc resistance corrected for skin and proximity effects.

$$R_{ac} = R_{dc}\left(1 + y_s + y_p\right)$$

Where R_{ac} is the ac resistance at the conductor operating temperature θ (Ω / *km*)

R_{dc} is the dc resistance at the conductor operating temperature θ (Ω / *km*)

y_s is the skin effect factor (see below)

y_p is the proximity effect factor (see below)

The skin effect factor is calculated as follows:

$$y_s = \frac{x_s^4}{192 + 0.8x_s^4}$$

Where $$x_s^4 = \left(\frac{8\pi f}{R_{dc}} k_s \times 10^{-7} \right)^2$$

R_{dc} is the dc resistance at the conductor operating temperature θ (Ω / *km*)

f is the supply frequency (Hz)

k_s is a constant (see table below)

Note that the formula above is accurate provided that $x_s \leq$ 2.8.

The proximity effect factor varies depending on the conductor geometry. For round conductors, the following formulae apply.

For 2C and 2 x 1C cables:

$$y_p = \frac{x_p^4}{192 + 0.8x_p^4} \left(\frac{d_c}{s} \right)^2 \times 2.9$$

For 3C and 3 x 1C cables:

$$y_p = \frac{x_p^4}{192 + 0.8x_p^4} \left(\frac{d_c}{s} \right)^2 \left[0.312 \left(\frac{d_c}{s} \right)^2 + \frac{1.18}{\frac{x_p^4}{192+0.8x_p^4} + 0.27} \right]$$

Where $$x_p^4 = \left(\frac{8\pi f}{R_{dc}} \times 10^{-7} \right)^2$$

R_{dc} is the dc resistance at the conductor operating temperature θ (Ω / *km*)

f is the supply frequency (Hz)

d_c is the diameter of the conductor (mm)

s is the distance between conductor axes (mm)

k_p is a constant (see table below)

Note that the formula above is accurate provided that $x_s \leq$ 2.8.

For shaped conductors, the proximity effect factor is two-thirds the values calculated above, and with:

d_c Equal to the diameter of an equivalent circular conductor of equal cross-sectional area and degree of compaction (mm)

$s = d_c + t$ Where t is the thickness of the insulation between conductors (mm)

Type of Conductor	Dried and Impregnated?	k_s	k_p
Copper			
Round, stranded	Yes	1	0.8
Round, stranded	No	1	1
Round, segmental	-	0.435	0.37
Sector-shaped	Yes	1	0.8
Sector-shaped	No	1	1
Aluminum			
Round, stranded	Either	1	1
Round, 4 segment	Either	0.28	0.37
Round, 5 segment	Either	0.19	0.37
Round, 6 segment	Either	0.12	0.37

Cable Reactance

The series inductive reactance of a cable can be approximated by the following equation:

$$X_c = 2\pi f \left[K + 0.2 \ln \left(\frac{2s}{d_c} \right) \right] \times 10^{-3}$$

Where X_c is the conductor inductive reactance (Ω / *km*)

f is the supply frequency (Hz)

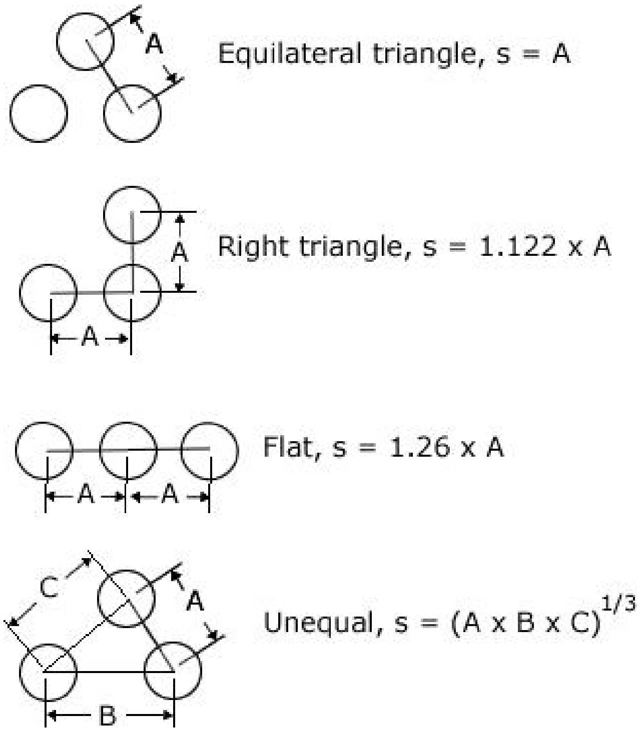
s is the axial spacing between conductors (mm)

d_c is the diameter of the conductor, or for shaped conductors, the diameter of an equivalent circular conductor of equal cross-sectional area and degree of compaction (mm)

K is a constant factor pertaining to conductor formation (see below for typical values)

No. of wire strands in conductor	K
3	0.0778
7	0.0642
19	0.0554
37	0.0528
>60	0.0514
1 (solid)	0.0500

For 3C and 3 x 1C cables, the axial spacing parameter s depends on the geometry of the conductors:



References

- IEC 60287-1-1, "Electric cables – Calculation of current rating – Part 1: Current ra ng equa ons (100% load factor) and calculation of losses – Sec on 1: General", 2006
- G.F. Moore, "Electric Cables Handbook", Third Edi on, 1997, an excellent reference book for cables

Cable Insulation Materials

The following materials are typically used for cable insulation:

Contents

Thermoplastic

Thermoplastic compounds are materials that go soft when heated and harden when cooled:

- PVC (Polyvinyl Chloride) – is the most commonly used thermoplastic insulator for cables. It is cheap, durable and widely available. However, the chlorine in PVC (a halogen) causes the production of thick, toxic, black smoke when burnt and can be a health hazard in areas where low smoke and toxicity are required (e.g. confined areas such as tunnels).

- PE (Polyethylene) – is part of a class of polymers called polyolefins. Polyethylene has lower dielectric losses than PVC and is sensitive to moisture under voltage stress (i.e. for high voltages only).

Thermosetting

Thermosetting compounds are polymer resins that are irreversibly cured (e.g. by heat in the vulcanization process) to form a plastic or rubber:

- XLPE (Cross-Linked Polyethylene) – has different polyethylene chains linked together ("cross-linking") which helps prevent the polymer from melting or separating at elevated temperatures. Therefore XLPE is useful for higher temperature applications. XLPE has higher dielectric losses than PE, but has better ageing characteristics and resistance to water treeing.

- EPR (Ethylene Propylene Rubber) – is a copolymer of ethylene and propylene, and commonly called an "elastomeric". EPR is more flexible than PE and XLPE, but has higher dielectric losses than both.

Paper Based

Paper Based insulation is the oldest type of power cable insulation and is still used mainly for high voltage cables. The paper insulation must be impregnated with a dielectric fluid (e.g. oil resin or a synthetic fluid). A lead sheath is commonly applied over the insulation to prevent water or moisture ingress into the paper insulation, which is sensitive to moisture.

Comparison of Materials

A comparison of common insulating materials is as follows:

Material	Advantages	Disadvantages
PVC	• Cheap • Durable • Widely available	• Highest dielectric losses • Melts at high temperatures • Contains halogens • Not suitable for MV / HV cables
PE	• Lowest dielectric losses • High initial dielectric strength	• Highly sensitive to water treeing • Material breaks down at high temperatures
XLPE	• Low dielectric losses • Improved material properties at high temperatures • Does not melt but thermal expansion occurs	• Medium sensitivity to water treeing
EPR	• Increased flexibility • Reduced thermal expansion (relative to XLPE) • Low sensitivity to water treeing	• Medium-High dielectric losses • Requires inorganic filler / additive
Paper / Oil	• Low-Medium dielectric losses • Not harmed by DC testing • Known history of reliability	• High weight • High cost • Requires hydraulic pressure / pumps for insulating fluid • Difficult to repair • Degrades with moisture

Cable Sheath Materials

The following materials are typically used for cable inner (bedding) and outer sheaths:

Thermoplastic

Thermoplastic compounds are materials that go soft when heated and harden when cooled:

- PVC (Polyvinyl Chloride) – as a sheath material, PVC is used extensively because of its low cost and good overall properties – high physical strength, good moisture resistance, adequate oil resistance, good flame resistance and excellent resistance to weathering and to soil environments. PVC contains halogens which produces thick, black toxic smoke when burnt. Most commonly used sheath material for LV cables.

- PE (Polyethylene) – is usually categorized under three different densities – 1) Low density (0.91 – 0.925 g/cm3), 2) Medium density (0.926 – 0.94 g/cm3), and 3) High density (0.941 – 0.965 g/cm3). PE sheaths have good physical strength, excellent moisture resistance, good ageing properties, but poor flame resistance. Like PVC, PE will melt at high temperatures. Does not contain halogens.

- CPE (Chlorinated Polyethylene) – similar to PVC, but with better high temperature properties. Contains halogens.

- TPE (Thermoplastic Elastomeric) – provides flame resistance, good low temperature performance, good abrasion resistance and good physical strength. Does not contain halogens.

- Nylon – provides good physical strength, reasonable abrasion resistance, very low friction when in contact with conduit materials which aids in pulling cables. Excellent resistance to oils and organic solvents, but very sensitive to strong acids and oxidizing agents.

Thermosetting

Thermosetting compounds are polymer resins that are irreversibly cured (e.g. by heat in the vulcanization process) to form a plastic or rubber:

- XLPE (Cross-Linked Polyethylene) – provides tough, moisture, chemical and weather resistant sheath material. Used mainly as an outer sheath material for “rugged” cables.

- PCP (Polychloroprene) or trade name "Neoprene" – provides good heat resistance, flame resistance, resistance to oil, sunlight and weathering, low temperature resistance and abrasion resistance. Due to its ruggedness, neoprene is used widely in the mining industry. Does not deform with high temperatures and does not contain halogens.

- CSP (Chloro-sulphanated Polyethylene) – similar properties to neoprene, though superior in resistance to heat, oxidizing chemicals, ozone and moisture, and has better dielectric properties. However CSP contains halogens.

- EPR (Ethylene Propylene Rubber) – not commonly used as a sheath material, but can be useful if increased cable flexibility is required (especially in low temperature applications).

Cable Terminology

List of electrical and instrumentation cable terminology and definitions

Contents

CPE (Chlorinated Polyethylene)

An oil, ozone and heat resistant thermoplastic sheathing material

CSP / CSPE (Chloro-sulphanated Polyethylene)

An oil, ozone and heat resistant elastomeric compound used as bedding and outer sheath material. DuPont manufacture this material under the registered trade name "Hypalon".

Dekoron®

Registered trade name for a range of instrumentation cables insulated and sheathed with flame retardant PVC. The standard range includes up to 50 pairs and up to 36 triples in either 0.5mm2 or 1.5mm2 conductors. Larger conductors may be specified, as can options of Lead Sheathing, SWA, or HF insulation and sheath materials.

EPR (Ethylene Propylene Rubber)

A water and ozone resistant, flexible, cross linked high grade insulation material and sometimes as a sheathing material

FR (Fire Resistant / Flame Retardant)

Fire Resistant - the property of cables to continue to function while under the influence of fire. Cables that are Fire Resistant tend to provide circuit integrity even when burned and maintains integrity after the fire has extinguished. In most cases, the cables will withstand a water spray and still provide circuit integrity.
Flame Retardant - the property of cables to retard or slow the progress of fire and flame along the cable. This is achieved through the use of materials that do not readily burn and will tend to self-extinguish.

GSWB (Galvanized Steel Wire Braid)

A type of cable armouring for mechanical protection

HDPE (High Density Polyethylene)

Generally used as a subsea cable sheathing material where it provides high resistance to water penetration, is very hard, has low coefficient of friction, and is abrasion resistant.

HF (Halogen Free)

Halogenated plastics (i.e. those that contain chlorine, fluorine, bromine, iodine and astatine) when ignited will tend to release toxic and corrosive gases, which has potential safety implications, e.g. obstruction of escape routes. Halogen free plastics, as the name suggests, do not contain halogens.

HOFR (Heat, Oil and Flame Retardant)

Refer to FR (flame retardant).

LSF (Low Smoke and Fumes)

Low smoke and fume emissions when the cable is on fire. Note that it may still contain halogens.

LSTA (Low Smoke, Toxicity and Acidity)
Uncommonly used term for bedding and sheathing materials with low smoke, toxicity and acidity properties, Halogen free materials such as SHF2 are more or less equivalent to LSTA materials.

LSZH / LS0H (Low Smoke, Zero Halogen)
Refer to HF (halogen free).

MGT (Mica Glass Tape)
A fire resistant tape usually wrapped around the insulated conductor bundle beneath the innear sheath.

Neoprene®
Refer to PCP (polychroloprene)

NYL (Nylon sheath)
A nylon sheath (or sometimes described as a sock) is typically used for termite protection in underground cables and also as a sheathing material.

PCP (Polychloroprene)
This is an oil resistant, tough sheathing material that is used mainly in mining cables as an outer sheath. DuPont registered trade name for this product is "Neoprene".

PE (Polyethylene)
Thermoplastic used as an insulation and sheathing material.

PETP (Polyethylene Terephthalate)
A polymer resin used in semi-metallic screens e.g. PETP/Al

PVC (Polyvinyl Chloride)
Commonly used thermoplastic insulation and sheathing material.

SCN (Screen)
A tape or braid, usually metallic (copper, aluminum) or semi-metallic (PETP/Al), wrapped around the cable cores to keep out or contain unwanted radiation / interference.

SHF2
Halogen free elastomeric compound commonly used for inner sheath / bedding and outer sheathing materials

SWA (Steel Wire Armour)
A type of cable armouring for mechanical protection

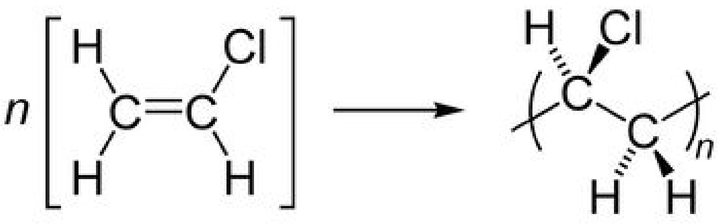
TAC (Tinned Annealed Copper)
Annealed copper conductors with surface tinning for rust prevention, Annealing refers to the process of gradually heating and cooling the copper making it more malleable and less brittle.

TCWB (Tinned Copper Wire Braid)
Typically used for flexible cable armouring of instrument cables.

TPE (Thermoplastic Elastomer)
A plastic material compounded so it displays characteristics like an elastomeric. TPE is normally tough, cut resistant, flexible, and smooth, with vibrant coloring.

XLPE (Cross-Linked Polyethylene)
High grade insulation material of cross-linked polyethylene chains giving good high temperature performance.

PVC



Basic PVC polymer chain (courtesy of Wikipedia)

Polyvinyl Chloride (PVC) is a thermoplastic material characterized by a polymer chain comprising of the basic unit in the figure right.

PVC is cheap to produce and quite durable. Many variations of PVC can be formulated for different applications based on the type of plasticizer that is added to the basic PVC polymer. For example, PVC can be made to be rigid or flexible based on the plasticizer used.

Electrical Applications

Cables

PVC is a commonly used material for electrical cable insulation and sheathing. Refer to IEC 60502 for the requirements on PVC (in terms of plasticizer additives) to be regarded suitable as an electric cable insulation and sheathing material. These requirements include the electric properties of the material such as permittivity, dielectric loss angle, etc.

Advantages:

- Cheap
- Durable
- Widely available

Disadvantages:

- Highest dielectric losses
- Melts at high temperatures
- Contains halogens
- Not suitable for MV / HV cables

Cross-linked polyethylene

Cross-linked polyethylene, commonly abbreviated **PEX** or **XLPE**, is a form of polyethylene with cross-links. It is formed into tubing, and is used predominantly in hydronic radiant heating systems, domestic water piping and insulation for high tension (high voltage) electrical cables. It is also used for natural gas and offshore oil applications, chemical transportation, and transportation of sewage and slurries.

Properties

Almost all PEX is made from high density polyethylene (HDPE). PEX contains cross-linked bonds in the polymer structure, changing the thermoplastic to a thermoset. Cross-linking is accomplished during or after the extrusion of the tubing. The required degree of cross-linking, according to ASTM Standard F 876-93, is between 65 and 89%. A higher degree of cross-linking could result in brittleness and stress cracking of the material.

The high-temperature properties of the polymer are improved. Adequate strength to 120-150°C is maintained by reducing the tendency to flow. Chemical resistance is enhanced by resisting dissolution. Low temperature properties are improved. Impact and tensile strength, scratch resistance, and resistance to brittle fracture are enhanced.

PEX- or XLPE-insulated cables have a rated maximum conductor temperature of 90°C and an emergency rating up to 140°C, depending on the standard used. They have a conductor short-circuit rating of 250°C.
XLPE has excellent dielectric properties, making it useful for medium voltage - 10 to 50 kV AC - and high voltage cables - up to 380 kV AC-voltage, and several hundred kV DC.

Numerous modifications in the basic polymer structure can be made to maximize productivity during the manufacturing process. For medium voltage applications, reactivity can be boosted significantly. This results in higher line speeds in cases where limitations in either the curing or cooling processes within the continuous vulcanization (CV) tubes used to cross-link the insulation. PEX insulations can be modified to limit the amount of by-product gases generated during the cross-linking process. This is particularly useful for high voltage cable and extra-high voltage cable applications, where degassing requirements can significantly lengthen cable manufacturing time

Columbic Efficiency

The columbic efficiency of a battery is defined as follows:

$$\eta_c = \frac{C_{in}}{C_{out}}$$

Where η_c is the columbic efficiency (PU)

C_{in} is the amount of charge that enters the battery during the charging cycle (C)

C_{out} is the amount of charge that exits the battery during the discharge cycle (C)

Columbic efficiency is not 100% because of losses in charge, largely because of secondary reactions, such as the electrolysis of water or other redox reactions in the battery. The columbic efficiency of a typical lead-acid battery is >95%.

Complex Impedance

Complex impedances are commonly used quantities in the analysis of AC power systems. Complex impedance is represented by the following relation:

$$Z = R + jX$$

Where Z is the complex impedance (Ω)

R is the resistance (Ω)

X is the reactance (Ω)

j is the complex component, i.e. $\sqrt{-1}$)

For more details about why complex quantities are used in electrical engineering, see the article on complex power.

Complex Arithmetic

The manipulation of complex impedances follows the rules of complex arithmetic

Series Impedances

Two impedances in series can be combined by simply adding the individual real and complex terms (i.e. resistance and reactance components). For example, given:

$$Z_1 = R_1 + jX_1$$

$$Z_2 = R_2 + jX_2$$

Then,

$$Z_1 + Z_2 = R_1 + R_2 + j\left(X_1 + X_2\right)$$

Parallel Impedances

Two impedances in parallel can be combined according to the following standard relation:

$$Z_1 || Z_2 = \frac{Z_1 Z_2}{Z_1 + Z_2}$$

However, note that the multiplication and division of complex numbers is more involved than simply multiplying or dividing the real and complex terms:

- **Multiplication:** involves multiplying cross-terms, i.e.

$$Z_1 \times Z_2 = \left(R_1 + jX_1\right)\left(R_2 + jX_2\right)$$
$$= R_1R_2 + j^2 X_1X_2 + j\left(R_1X_2\right) + j\left(X_1R_2\right)$$
$$= R_1R_2 - X_1X_2 + j\left(R_1X_2 + X_1R_2\right)$$

- **Division:** involves multiplying by the complex conjugate of the denominator, i.e

$$\frac{Z_1}{Z_2} = \frac{\left(R_1 + jX_1\right)}{\left(R_2 + jX_2\right)}$$
$$= \frac{\left(R_1 + jX_1\right)}{\left(R_2 + jX_2\right)} \times \frac{\left(R_2 - jX_2\right)}{\left(R_2 - jX_2\right)}$$
$$= \frac{R_1R_2 + X_1X_2 + j\left(R_1X_2 - X_1R_2\right)}{\left(R_2^2 + X_2^2\right)}$$

Contact Resistance Test

The contact resistance test (commonly known as the Ductor test) measures the resistance of electrical connections such as joints, terminations, connectors, etc. These can be connections between any two conductors, for instance busbar sections or cable connections. The test measures the resistance at the micro- or mille-ohm level and is used primarily to verify that electrical connections are made properly, and can detect the following problems:

- Loose connections
- Adequate tension on bolted joints
- Eroded contact surfaces
- Contaminated or corroded contacts

This is particularly important for contacts that carry large amounts of current (e.g. switchgear busbars) as higher contact resistance leads to higher losses and lower current carrying capacity.

Test Equipment

Contact resistance tests are normally performed using a micro/mille-ohmmeter or low resistance ohmmeter. "Ductor" was the name originally given to the low resistance ohmmeter manufactured by the Megger company, which became an industry standard.

Test Criteria

The criteria for evaluating the contact resistance of electrical connections largely depends on the type of connection (e.g. bolted, soldered, clamped, welded, etc), the metallic contact surface area, the contact pressure, etc. These will differ by equipment and manufacturer and there is no code or standard that mandates minimum contact resistances. As such, manufacturer recommendations need to be consulted. For example, manufacturers sometimes quote a maximum contact resistance of 10 micro-ohms for large bolted busbar joints.

International Standards

- ASTM B539-02 (R2008), "Standard Test Method for Measuring Resistance of Electrical Connec ons (Sta c Contacts)"

Dry-Type Transformer Testing

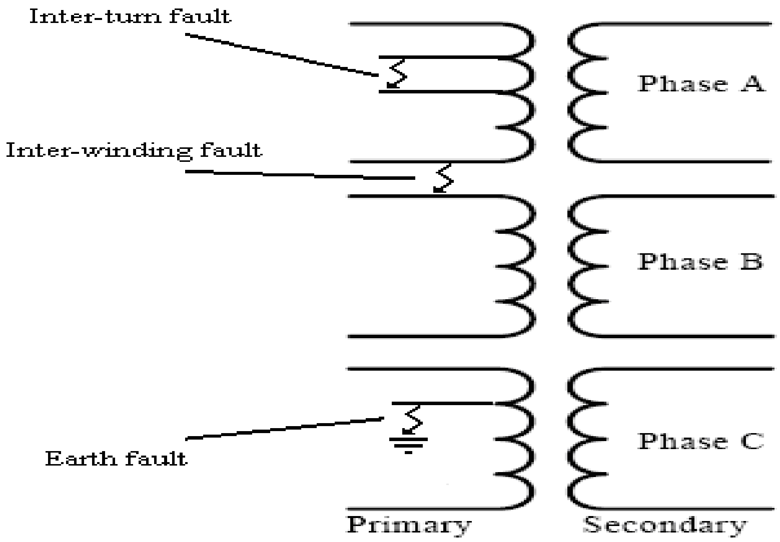
Contents

Introduction

The primary concern with all transformers (and also the key indicator of life expectancy) is the condition of the insulation system.

For dry type transformers, the insulation system consists of the cast resin winding and core insulation and the termination system insulation (e.g. bushings). The structural strength and insulating properties of materials used for these insulation systems degrade over time through normal ageing. They can also degrade prematurely as a result of overheating and mechanical and electrical stresses (e.g. faults, overvoltages, inrush currents, etc).

The initial breakdown of insulation around the windings can result in inter-turn faults, especially on the high voltage windings where the electric field strength is high enough to ionize air gaps and cause corona activity. Inter-turn faults are short circuits between coil turns on a single winding. Further degradation of the insulation could see inter-turn faults develop into more serious faults such as inter-winding and earth faults.



Testing

The most frequent mode of failure for dry type transformers is insulation breakdown resulting in inter-turn faults which leads to more severe faults such as phase to phase winding or earth faults. The insulation condition of component parts of the transformer (i.e. windings, core, bushings, etc) can be determined by a suite of tests.

Dissolved gas analysis is the most commonly used method for determining winding insulation condition in oil-type transformers, but is not possible for dry-type transformers.

The following tests are discussed further:

- Insulation resistance / polarization index tests
- Dielectric loss angle measurement tests
- Partial discharge tests
- Frequency response analysis
- Acoustic emission tests (in conjunction with partial discharge tests)
- Thermo-graphic surveys

Insulation Resistance Tests

Insulation resistance, measured by application of an impressed DC voltage (i.e. Megger), gives a general indication of the insulation condition between the phase windings and earth. The measurements are typically taken over time (i.e. 1 minute intervals over 10 minutes) to generate a curve, called the Dielectric Absorption curve.

The Polarization Index is the steepness of the curve at a given temperature and is defined as per the following equation [1]:

$$PI = \frac{R_{10}}{R_1}$$

Where

R_{10} = megohms insula on resistance at 10 minute

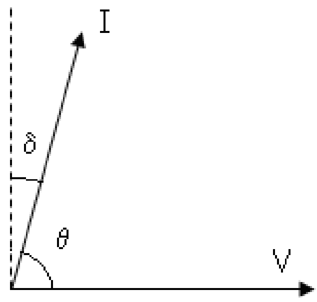
R_1 = megohms insula on resistance at 1 minute

The Polarization Index indicates the relative dryness and level of moisture ingress into the insulation.

Dielectric Loss Angle Measurement Tests

Dielectric loss angle tests, also called dissipation factor, power factor or tan delta tests, determine the insulation dielectric power loss by measurement of the power angle between an applied AC voltage and the resultant current. In the ideal insulator, the power angle would be 90°C as it is purely capacitive and non-conducting. However in real insulators, there is some leakage current and resistive losses through the dielectric.

Relative increases in dielectric power losses are indicative of insulation deterioration and may further accelerate degradation due to increased heating. Note that dielectric power loss does not translate to dielectric strength, though there are often common causes for increases in power loss and decreases in dielectric strength.



The cosine of the power angle (θ) is called the power factor. The complement of θ is denoted δ as shown in the diagram above. The power factor can be practically approximated by taking the tangent of δ (hence the name tan delta). This approximation is called the dissipation factor and is roughly equal to the power factor between values of 0 and 0.08, which covers the majority of tests.

The dissipation factor is essentially the ratio between the resistive and capacitive components of the insulation and can be measured directly (via a capacitance bridge circuit). The lower the quality of the insulation condition, the more resistive it will appear and the more power loss will be dissipated through it (in the form of heat).

The increase in the dissipation factor values as the test voltage is increased is called the "tip-up".

The technical literature on this subject has noted that this test is useful for detecting moisture ingress in the bushings and windings. About 90% of bushing failures may be attributed to moisture ingress evidenced by an increasing power factor from dielectric loss angle testing on a scheduled basis.

Partial Discharge Tests

Partial discharges are localized incipient electrical discharges that only partially bridge the insulation between conductors. Partial discharges can occur in any location where the local electrical field strength is sufficient to breakdown that portion of the dielectric material (whether it be deteriorated insulation or air). In dry-type transformers they can occur within air-filled voids where the solid insulation has degraded.

Partial discharge testing can detect the presence and location of partial discharge activity in a transformer. Partial discharges in transformers are typically measured by applying a pre-specified voltage to the transformer windings and measuring induced charges via a coupling device (e.g. coupling capacitors).

AS 60076.11 and AS 60270 set out the requirements, procedure, equipment and acceptance levels for partial discharge testing [3] [4] It should be noted that the partial discharge tests specified in AS 60076.11 are intended as routine tests for new transformers. This involves applying a "pre-stress" voltage of 1.8 times rated voltage to the windings. This may be excessive for transformers already in service for over 20 years.

Analysis of the partial discharge measurements gathered (i.e. pulse waveforms, magnitude, duration and intervals between pulses) can be used as a guide regarding the condition of the insulation. The results can be trended to chart the rate of insulation degradation between consecutive tests.

Frequency Response Analysis

Frequency response analysis is a diagnostic testing technique that measures the impedance of the transformer windings over a wide range of frequencies. The measurements are compared with a reference set and the differences are highlighted. The differences may indicate mechanical damage to the windings (e.g. winding displacement or loose winding) and electrical faults (e.g. interturn faults).

Frequency response analysis can be achieved by either injecting a low voltage impulse into the winding (i.e. impulse response method) or by making a frequency sweep using a sinusoidal signal (i.e. swept frequency method).

For frequency response analysis to be useful, a baseline reference set of measurements need to be determined and periodic tests need to be conducted to compare the differences

Refer to research by S. Tenbohlen et al at the University of Stuttgart [5].

Acoustic Emission Tests

Partial discharges in transformers can also be detected and localized via acoustic emission testing. Acoustic emission testing is based on the acoustic detection of the partial discharge pulses and conversion to an electrical signal. Sensors are coupled to the surface of the transformer and during operation of the transformer, the output of the sensors are fed into an electronic module. The signals are filtered to remove noise and processed to determine the presence and location of any partial discharges in the transformer.

Thermo-graphic Surveys

Infrared thermography is commonly used in preventative maintenance to detect hotspots, especially at joints and terminations. IR Thermography cameras measure surface temperatures and the resulting thermal image can be used to identify overheating at the transformer terminations.

For thermographic surveys to be conducted, thermographic windows need to be installed looking at the terminations and windings.

References

1. Facili es Instruc on, Standards and Techniques Volume 3-1, “Tes ng Solid Insula on of Electrical Equipment”, U.S Department of the Interior, Reclama on Branch, December 1991
2. Facilities Instruction, Standards and Techniques Volume 3-31, “Transformer Diagnos cs”, U.S Department of the Interior, Reclama on Branch, June 2003
3. AS 60076.11, “Power transformers Part 11: Dry-type transformers”, 2006
4. AS 60270, “High-voltage test techniques – Par al discharge measurements”, 2001
5. Research at University of Stuttgart (including Tenbohlen's papers)

Electrical Power

How do the various formulae for electrical power fit together? What is the difference between DC, AC and complex power and how do they harmonize with our physical conceptions of energy and power.

Contents

Definition

By formal definition, any form of power (e.g. electrical, mechanical, thermal, etc) is the rate at which energy or work is performed. The standard unit of power is the watt (or joules per second). Electrical power is the rate at which electrical energy is delivered to a load (via an electrical circuit) and converted into another form of energy (e.g. heat, light, sound, chemical, kinetic, etc). In terms of electrical quantities current and voltage, power can be calculated by the following standard formula:

$$P = VI$$

Where P is power in watts, V is potential difference in volts and I is current in amperes. But how did this relationship come about?

DC Power

Historical Derivation

19th century English physicist James Prescott Joule observed that the amount of heat energy (H) dissipated by a constant (DC) electrical current (I), through a material of resistance R, in time t, had the following proportional relationship:

$$H \propto I^2Rt$$

As power is the rate of change of energy over time, Joule's observation above can be restated in terms of electrical power:

$$P \propto I^2 R$$

Since P=ΔH/Δt. Now applying Ohm's law R=V/I we get:

$$P \propto VI$$

Alternative Derivation

The SI unit for energy is the joule. For electrical energy, one joule is defined as the work required to move an electric charge of one coulomb through a potential difference of one volt. In other words:

$$E = QV$$

Where E is electrical energy (in joules), Q is charge (in coulombs) and V is potential difference (in volts) Given that electric current is defined as the amount of charge flowing per unit time (I = Q/t), then

$$E = VIt$$

As power is the rate of change of energy over time, this reduces to:

$$P = VI$$

Which is the familiar equation for electrical power

AC Power

In its unaltered form, the power equation P=VI is only applicable to direct current (DC) waveforms. In alternating current (AC) waveforms, the instantaneous value of the waveform is always changing with time, so AC power is slightly different conceptually to DC power.

Derivation

AC waveforms in power systems are typically sinusoidal with the following general form, e.g. for a voltage waveform:

$$v(t) = V \cos(\omega t - \phi)$$

Where V is the amplitude of the voltage waveform (volts)

ω is the angular frequency = 2πf

ϕ is the phase displacement

v(t) is the instantaneous value of voltage at any time t (seconds)

If the current waveform i(t) had a similar form, then it can be clearly seen that the instantaneous power p(t)= v(t)i(t) also varies with time.

Suppose the current and voltage waveforms are both sinusoids and have a phase difference such that the current lags the voltage by a phase angle θ. Therefore we can write voltage and current as:

$$v(t) = V\cos(\omega t)$$

$$i(t) = I\cos(\omega t - \theta)$$

The instantaneous power is therefore:

$$p(t) = v(t)i(t)$$

$$p(t) = V\cos(t)I\cos(\omega t - \theta)$$

$$p(t) = \frac{VI}{2}(\cos + \cos(2\omega t - \theta))$$

$$p(t) = \frac{VI}{2}(\cos + \cos(2\omega t)\cos\theta + \sin(2\omega t)\sin\theta)$$

$$p(t) = \frac{VI}{2}(\cos(1 + \cos(2\omega t)) + \sin(2\omega t)\sin\theta)$$

$$V_{rms} = \frac{V}{\sqrt{2}} \qquad I_{rms} = \frac{I}{\sqrt{2}}$$

Since the root-mean-square (rms) values of voltage and current are and, then

$$p(t) = V_{rms}I_{rms}(\cos\theta(1 + \cos(2\omega t)) + \sin(2\omega t)\sin\theta)$$

We can simplify this equation further by defining the following terms:

$$P = V_{rms}I_{rms}\cos\theta$$

and

$$Q = V_{rms}I_{rms}\sin\theta$$

We then get the final AC instantaneous power equation:

$$p(t) = P(1 + \cos(2\omega t)) + Q\sin(2\omega t)$$

The term P is called the active (or real) power and the term Q is called the reactive power.

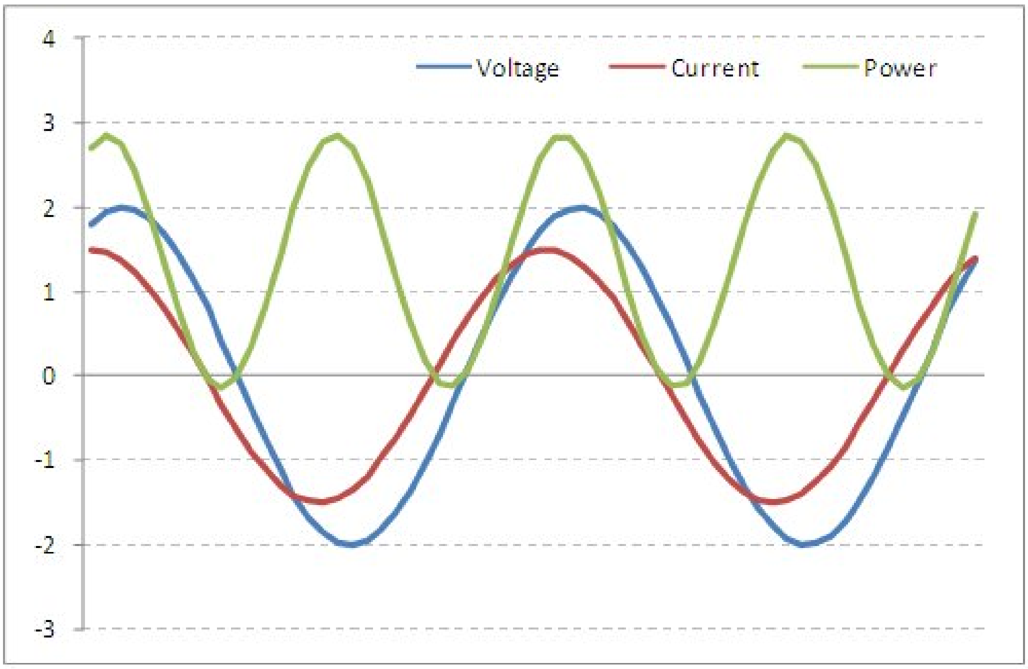
Note that the term cosθ is called the power factor and refers to the proportion of active or real component of AC power being delivered. The active power is the component of power that can do real work (e.g. be converted to useful forms of energy like mechanical, heat or light).

Physical Interpretation

From the basic power equation:

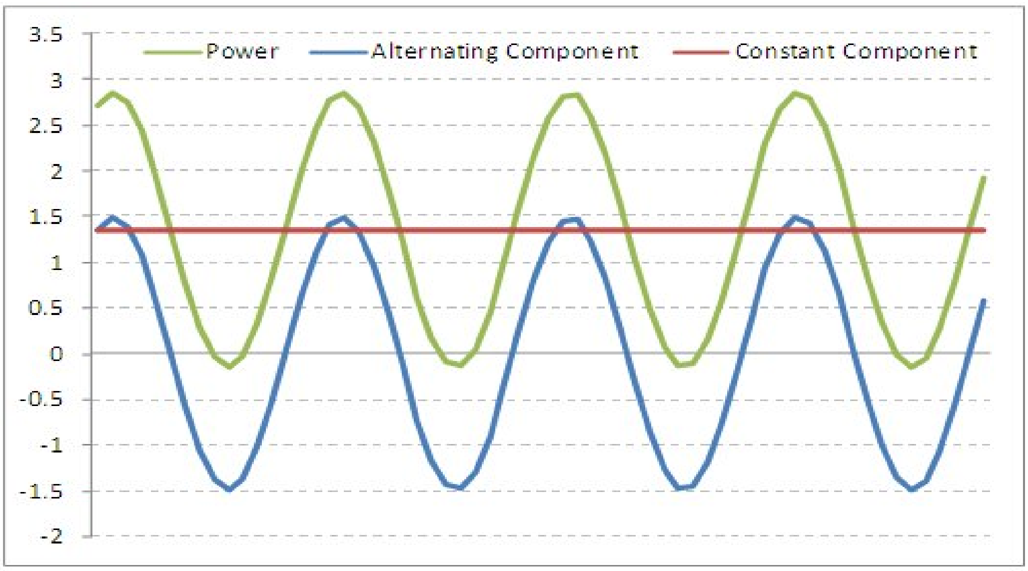
$$p(t) = \frac{VI}{2} \cos\theta + \cos(2\omega t - \theta)$$

We can see that power flow is a sinusoidal waveform with twice the frequency of voltage and current.



From the power equation, we can also break p(t) down into two components:

- A constant term (active power), $V_{rms} I_{rms} \cos\theta$
- An alternating term, $V_{rms} I_{rms} \cos(2\omega t - \theta)$



Notice that the alternating term fluctuates around zero and the constant term in the above example is positive. It turns out that the alternating term always fluctuates around zero and the constant term (active power) depends on the power factor cosθ. But what does the power factor represent?

Power Factor

Power factor is defined as the cosine of the power angle, the difference in phase between voltage and current. People will often refer to power factor as leading or lagging. This is because the power angle can only range between -90° and +90°, and the cosine of an angle in the fourth quadrant (between 0 and -90°) is always positive. Therefore the power factor is also always positive and the only way to distinguish whether the power angle is negative or positive from the power factor is to denote it leading or lagging.

- Lagging power factor: when the current lags the voltage, this means that the current waveform comes delayed after the voltage waveform (and the power angle is positive).
- Leading power factor: when the current leads the voltage, this means that the current waveform comes before the voltage waveform (and the power angle is negative).
- Unity power factor: refers to the case when the current and voltage are in the same phase.

The physical significance of power factor is in the load impedance. Inductive loads (e.g. coils, motors, etc) have lagging power factors, capacitative loads (e.g. capacitors) have leading power factors and resistive loads (e.g. heaters) have close to unity power factors.

Relation to Energy

By definition, power is the rate at which work is being done (or the rate at which energy is being expended). As AC power varies with time, the amount of energy delivered by a given power flow in time T is found by integrating the AC power function over the specified time:

$$E = \int_0^T p(t)dt$$

We can see that power is made up of a constant component $V_{rms}I_{rms}\cos\theta$ and an alternating component $V_{rms}I_{rms}\cos(2\omega t - \theta)$. The integration can therefore be broken up as follows:

$$E = \int_0^T V_{rms}I_{rms}\cos\theta dt + \int_0^T V_{rms}I_{rms}\cos(2\omega t - \theta)dt$$

Suppose we were to integrate over a single period of an AC power waveform (e.g. $T = \frac{\pi}{\omega}$). The alternating component drops out and the integration is solved as follows:

$$E = V_{rms}I_{rms}\cos\theta . \frac{\pi}{\omega}$$

From this we can see that work is done by the active power component only and the alternating component does zero net work, i.e. the positive and negative components cancel each other out.

Complex Power

Books often mention AC power in terms of complex quantities, mainly because it has attractive properties for analysis (i.e. use of vector algebra). But often, complex power is simply defined without being derived. So how do complex numbers follow from the previous definitions of power?

Derivation

Back in 1897, Charles Proteus Steinmetz first suggested representing AC waveforms as complex quantities in his book "Theory and Calculation of Alternating Current Phenomena". What follows is a sketch of Steinmetz's derivation, but specifically using AC power as the quantity under consideration.

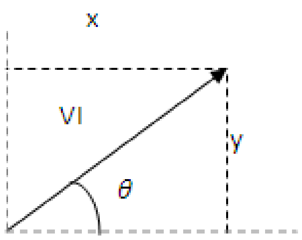
Previously, we found that AC power is a sinusoidal waveform with the general form:

$$p(t) = \frac{VI}{2} \cos\theta + \cos(2\omega t - \theta)$$

Where V and I are the rms values for voltage and current (A rms)

For a fixed angular frequency ω, this waveform can be fully characterized by two parameters: the rms voltage and current product VI and the phase angle θ.

Using these two parameters, we can represent the AC waveform p(t) as a two-dimensional vector S which can be expressed as a polar coordinate with magnitude VI and polar angle θ:



This vector S can be converted into a pair of rectangular coordinates (x, y) such that:

$$x = VI\cos\theta$$

$$y = VI\sin\theta$$

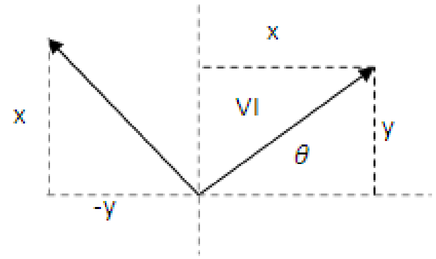
It can be shown trigonometrically that the addition and subtraction of AC power vectors follow the general rules of vector arithmetic, i.e. the rectangular components of two or more sinusoids can be added and subtracted (but not multiplied or divided!).

However working with each rectangular component individually can be unwieldy. Suppose we were to combine the rectangular components using a meaningless operator j to distinguish between the horizontal (x) and vertical (y) components. Our vector S now becomes:

$$S = x + jy$$

$$S = VI\cos\theta + jVI\sin\theta$$

Note that the addition sign does not denote a simple addition because x and y are orthogonal quantities in a two-dimensional space. At the moment, j is a meaningless operator to distinguish the vertical component of V. Now consider a rotation of the vector by 90°:



The rotated vector $S' = -y + jx$

Suppose we were to define the operator j to represent a 90° rotation so that multiplying a vector V by j rotates the vector by 90°. Therefore:

$$jS = S'$$

$$jx + j^2y = -y + jx$$

$$j^2 + 1 = 0$$

$$j = \sqrt{-1}$$

Therefore using our definition of j as a 90° rotation operator, j is actually an imaginary number and the vector S=x+jy is a complex quantity. Therefore our vector S

$$S = VI\cos\theta + jVI\sin\theta$$

Is referred to as “complex power” or “apparent power”. It is most commonly written in this form:

$$S = P + jQ$$

Where $P = VI\cos\theta$ and $Q = VI\sin\theta$ are the active (or real) and reactive power quantities defined earlier.

Complex Exponentials

Using Euler’s law, we can represent our complex power vector as a complex exponential using the original polar parameters:

$$S = VIe^{j\theta}$$

The use of complex exponentials gives us an alternative way to think about complex power. We have seen that the vector S rotates around the origin when we very the phase angle θ. The complex exponential $e^{j\theta}$ is actually a rotation operator used to rotate vectors around a circle in a two-dimensional space (there's a good explanation of this at Better Explained. Therefore $S = VI\exp^{j\theta}$ is a vector with magnitude VI rotated by angle *P* = θ.

In other words, complex power is a two-dimensional vector representation of AC power, which is more amenable for manipulation than the time-domain function of AC power p(t).

Apparent Power

In the previous section, we saw that complex power S is also called apparent power. However in practice, apparent power is often used to refer to the magnitude of S, which is $|S| = VI$.

Electrical Submersible Pump

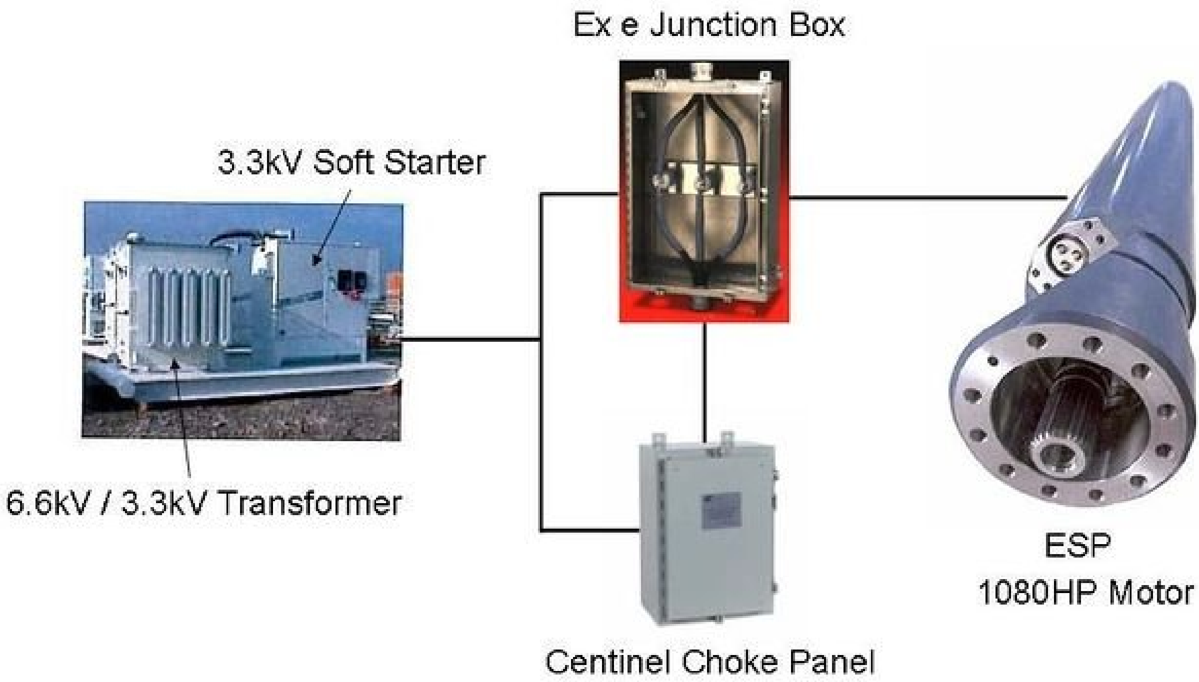
Contents

Introduction

An electrical submersible pump is a type of electrically driven pump designed to be lowered directly into the liquid to be pumped. It can be viewed as an artificial lift system which provides flexibility for various sizes and flow capacities.

ESP System Components

The entire ESP system typically consists of a number of components, as shown in the figure below:

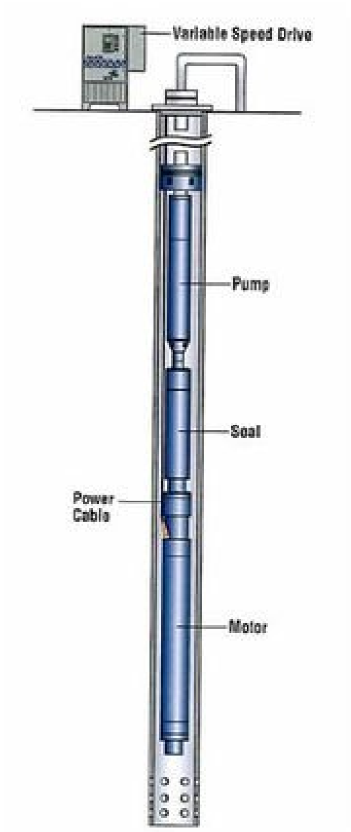


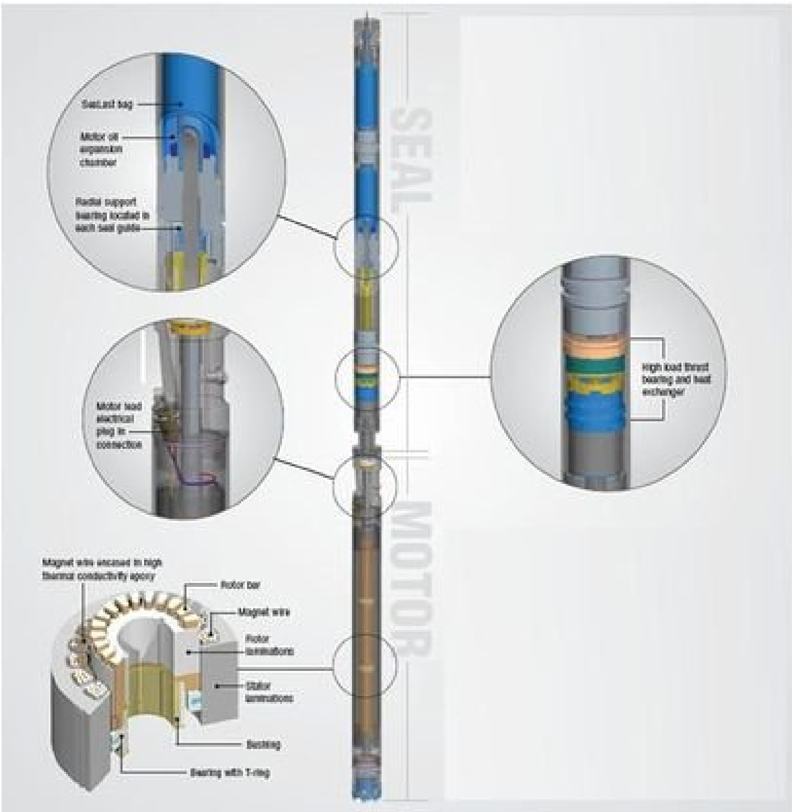
ESP System Topology (Centrilift example)

Electric Submersible Pump

The ESP string itself normally comprises the following sub-components:

- Pump - the guts of the ESP string is typically a series of staged centrifugal pumps
- Seal - the seal separates the pump from the motor, preventing pump fluid ingress into the motor and establishing the point of shaft coupling between motor and pump.
- Motor - hermetically sealed induc   on motor (typically 35kV)
- Power Cable - the motor power cable is typically a special type for ESP applications, connected to the motor via plug and socket.
- Down hole sensor (or gauge) - measures intake flow, temperature and pressure. In Centrilift designs, the data is transmitted digitally over the motor power cable.





Components of downhole electrical submersible pump

Surface Choke Panel

The surface choke panel is used where a downhole sensor is fitted on the ESP. It filters out the power signal from the motor power cable and demodulates the digitally transmitted signal from the downhole sensor. An electronic display shows the transmitted sensor data.

Junction Box

Junction box for connection of the surface power cable and downhole ESP cable

Variable Speed Drive / Soft Starter

Depending on the application, a variable speed drive or soft starter can be used. Variable speed drives can control the pump flow rates if required. Soft starters are typically used when a constant flow is sufficient.

Transformer

Transformer converts line voltage to suitable voltage for variable speed drive / soft starter. This particular voltage is somewhat subject to the whim of the manufacturer.

References

Refer to Baker Hughes Centrilift website for further information.

IP Rating

Contents

Introduction

IP Rating refers to the International Protection or Ingress Protection of electrical enclosures, against the intrusion of solid objects, water, dust and accidental contact to live parts, as defined by IEC 60529. The rating comprises the letters "IP" followed by two numbers (and an optional letter), where the numbers and letters refer to conformity to levels of protection.

The Wikipedia article gives a fairly detailed account of IP ratings. Therefore this page is only intended to be a summary of the ratings and more importantly, highlight some key points from IEC 60529 that are commonly overlooked.

Summary of IP Ratings

Level	First Number (Protected against solids of size:)	Second Number (Proection against water)
0	No protection against contact and ingress of objects	Not protected
1	>50 mm - Any large surface of the body, such as the back of a hand, but no protection against deliberate contact with a body part	Dripping water - Dripping water (vertically falling drops) shall have no harmful effect.
2	>12.5 mm - Fingers or similar objects	Dripping water when lted up to 15°- Vertically dripping water shall have no harmful effect when the enclosure is tilted at an angle up to 15° from its normal posi on.
3	>2.5 mm - Tools, thick wires, etc.	Spraying water - Water falling as a spray at any angle up to 60° from the vertical shall have no harmful effect.
4	>1 mm - Most wires, screws, etc.	Splashing water - Water splashing against the enclosure from any direction shall have no harmful effect.

5	Dust protected - Ingress of dust is not entirely prevented, but it must not enter in sufficient quantity to interfere with the satisfactory operation of the equipment; complete protection against contact	Water jets - Water projected by a nozzle (6.3mm) against enclosure from any direction shall have no harmful effects.
6	Dust tight - No ingress of dust; complete protection against contact	Powerful water jets - Water projected in powerful jets (12.5mm nozzle) against the enclosure from any direction shall have no harmful effects.
7	N/A	Immersion up to 1 m - Ingress of water in harmful quantity shall not be possible when the enclosure is immersed in water under defined condi ons of pressure and me (up to 1 m of submersion).
8	N/A	Immersion beyond 1 m - The equipment is suitable for continuous immersion in water under conditions which shall be specified by the manufacturer. Normally, this will mean that the equipment is hermetically sealed. However, with certain types of equipment, it can mean that water can enter but only in such a manner that produces no harmful effects.

Examples

An IP54 enclosure is dust protected (1st number = 5) and protected against splashing wayer (2nd number = 4).

An IP66/67 enclosure is dual protected, both for immersion up to 1m and powerful water jets. Note that it is not always true that an enclosure with a single rating such as IP68 is suitable for use in lower IP environments, such as IP66 (for more details, see the next section below).

Important Points from IEC 60529

Section 6 of IEC 60529 makes an important point about backward compliance of IP ratings for water protection, as per the extract below:

"Up to and including second characteris c numeral 6, the designa on implies compliance with the requirements for all lower characteristic numerals. However, the tests establishing compliance with any one of the lower degrees of protection need not necessarily be carried out provided that these tests obviously would be met if applied.

An enclosure designated with second characteris c numeral 7 or 8 only is considered unsuitable for exposure to water jets (designated by second characteris c numeral 5 or 6) and need not comply with requirements for numeral 5 or 6 unless it is dual coded."

Infinite Bus

The infinite bus concept is a simplifying assumption that is applied to buses or nodes with an infinite upstream fault capacity (or an equivalent upstream source impedance of zero). What this means is that the voltage at this bus or node is always constant and any downstream disturbances do not affect the voltage. Obviously, there is no such thing as an infinite bus in practice, but it is a useful approximation to make when modelling a connection to a large utility or grid network (that is, large relative to the downstream system). Such large networks are sometimes called "stiff" networks or systems.

Insulation Resistance Test

The insulation resistance (IR) test (also commonly known as a Megger) is a spot insulation test which uses an applied DC voltage (typically either 250Vdc, 500Vdc or 1,000Vdc for low voltage equipment <600V and 2,500Vdc and 5,000Vdc for high voltage equipment) to measure insulation resistance in either kΩ, MΩ or GΩ. The measured resistance is intended to indicate the condition of the insulation or dielectric between two conductive parts, where the higher the resistance, the better the condition of the insulation. Ideally, the insulation resistance would be infinite, but as no insulators are perfect, leakage currents through the dielectric will ensure that a finite (though high) resistance value is measured.

Because IR testers are portable, the IR test is often used in the field as the final check of equipment insulation and also to confirm the reliability of the circuit and that there are no leakage currents from unintended faults in the wiring (e.g. a shorted connection would be obvious from the test results).

One of the advantages of the IR test is its non-destructive nature. DC voltages do not cause harmful and/or cumulative effects on insulation materials and provided the voltage is below the breakdown voltage of the insulation, does not deteriorate the insulation. IR test voltages are all well within the safe test voltage for most (if not all) insulation materials.

Contents

Test Equipment

IR test set (courtesy of Megger)

The Megger company were the original manufacturers of IR test equipment over 100 years ago and have become synonymous with insulation resistance testing. Most modern IR testers are digital, portable / handheld units and some have multi-functional capabilities (e.g. built-in continuity testing).

Test Procedure

Firstly ensure that the equipment to be tested and the work area is safe, e.g. equipment is de-energized and disconnected, all the relevant work permits have been approved and all locks / tags in place.

Next, discharge capacitances on the equipment (especially for HV equipment) with static discharge sticks or an IR tester with automatic discharging capabilities.

The leads on the IR tester can then be connected to the conductive parts of the equipment. For example, for a three-core and earth cable, the IR test would be applied between cores (Core 1 to Core 2, Core 1 to Core 3 and Core 2 to Core 3) and between each core and earth. Similarly for three-phase motors, circuit breakers, switch-disconnectors, etc the IR test can be applied at the equipment terminals (and earth connection).

Note that when applying an IR test to earth, it is good practice to connect the positive pole of the IR tester to earth in order to avoid any polarization effects on the earth.

Once connected, the IR tester is energized for a typical test duration of 1 minute. The IR test measurements are recorded after 1 minute.

When the IR test is finished, discharge capacitances again for a period of 4-5 times the test duration.

Interpretation of Test Results

The minimum values for IR tests vary depending on the type of equipment and the nominal voltage. They also vary according to international standards. Some standards will define the minimum IR test values for the general electrical installations.

For example, for low voltage installations in the IEC world, IEC 60364-6 [1] Table 6A gives the minimum IR values and also suggests test voltage, i.e.

Nominal Circuit Voltage (Vac)	Test Voltage (Vdc)	Insulation Resistance (MΩ)
Extra low voltage	250	$\geq$ 0.5
Up to 500V	500	$\geq$ 1.0
Above 500V	1,000	$\geq$ 1.0

In the ANSI/NEC world, the standard ANSI/NETA ATS-2009 [2] provides test procedures and acceptance levels for most types of electrical equipment. Table 100.1 provides representative acceptance values for IR test measurements, which should be used in the absence of any other guidance (from the manufacturer or other standards):

Nominal Equipment Voltage (Vac)	Min Test Voltage (Vdc)	Min Insulation Resistance (MΩ)
250	500	25
600	1,000	100
1,000	1,000	100
2,500	1,000	500
5,000	2,500	1,000
8,000	2,500	2,000
15,000	2,500	5,000
25,000	5,000	20,000
34,500 and above	15,000	100,000

NFPA 70B [3] also provides some guidance on insulation resistance testing for different types of equipment.

Factors Affecting Test Results

There are two main factors that will affect IR test results:

Temperature

Electrical resistance has an inverse exponential relationship with temperature, i.e. as temperature increases, resistance will decrease and vice versa. Since the minimum acceptable IR test values are based on a fixed reference temperature (usually 20°C), the measured IR test values must be corrected to the reference temperature in order to make sense of them.

As a rule of thumb, the resistance halves for every 10°C increase in temperature (and vice versa). So if the measured IR test value was 2MΩ at 20°C, then it would be 1MΩ at 30°C or 4MΩ at 10°C.

ANSI/NETA ATS-2009 Table 100.14 provides correction factors for IR test measurements taken at temperatures other than 20°C or 40°C, which were in turn based on the correction factors in the freely available Megger book "A stitch in time..." [4].

Humidity

The presence (or lack) of moisture can also affect the IR test measurements, the higher the moisture content in the air, the lower the IR test reading. If possible, IR tests should not be carried out in very humid atmospheres (below the dew point). While there are no standard correction factors or guidance for humid conditions, it is good practice to record the relative humidity of each IR test so that they can be used for baseline comparisons in future tests. For example, having past data on the IR test values for dry and humid days will give you a foundation for evaluating future test values.

Related Tests

For equipment maintenance, the Dielectric Absorption Test is normally performed in conjunction with the IR test using the same testing equipment. The results are either in the form of a Dielectric Absorption Ratio (DAR) or a Polarization Index (PI). Refer to the Dielectric Absorption Test article for more details.

References

- 1. IEC 60364-6, "Low voltage electrical installa ons- Part 6: Verifica on", 2006
- 2. ANSI/NETA ATS, "Standard for Acceptance Tes ng Specifications for Electrical Power Equipment and Systems", 2009
- 3. NFPA 70B, "Recommended Prac ce for Electrical Equipment Maintenance", 2010
- 4. Megger, "A stitch in time - The Complete Guide to Electrical Insulation Testing", a free book which is an excellent resource on IR testing

Load Redundancy

Load redundancy is the duplication of load equipment so that an alternative can be used in case one fails or needs to be maintained. Redundancy is common in industrial plants where loads such as pumps, fans, compressors, etc need to operate continuously. In order for there to be minimal plant downtime, these loads are replicated to ensure some redundancy.

Most commonly, the use of duty and standby equipment ("A" and "B" loads) is used. In a scenario where the A/B loads are 100% redundant, the equipment can be referred to as "2 x 100%", meaning that there are 2 equipment items capable of delivering 100% output each.

Other examples of redundant (and semi-redundant) configurations:

- 2 x 50% - 2 equipment items capable of delivering 50% output each. If one fails, then output is reduced to 50%.
- 3 x 50% - 3 equipment items capable of delivering 50% output each. In this case, there is always one equipment item out of service / on standby
- 3 x 33% - 3 equipment items capable of delivering 33% output each. If one fails, then output is reduced to 66%.

Load factor

The load factor represents the operating / duty point of a load and is defined as the ratio of the absorbed power to the rated power, i.e.

$$LF \quad \frac{P_{abs}}{P_{rated}}$$

Where LF is the load factor (pu)

P_{abs} is the absorbed power of the load (kW)

P_{rated} is the rated power of the load (kW)

NEC Cable Types

The National Electricity Code (NEC or NFPA 70) includes a series of cable types for fixed wiring in Article 310.104. This page provides an outline of the cable types listed in the standard (based on NEC 2011 edition).

List of Cable Types

Cable Type	Max Operating Temperatures (°C / °F)	Description	Application
FEP / FEPB	90 / 194 200 / 392	Fluorinated etyhlene propylene (FEP) Fluorinated etyhlene propylene with braid (FEPB)	FEP: dry and damp locations FEPB: dry locations
MI	90 / 194 250 / 482	Mineral insulated (metal sheathed)	90°C: dry and wet locations 250°C: special applications
MTW	60 / 140 90 / 194	Moisture, heat and oil resistant thermoplastic	60°C: machine tool wiring in wet locations 90°C: machine tool wiring in dry locations
PFA / PFAH	90 / 194 200 / 392 250 / 482	Perfluoro-alkoxy (PFA) Perfluoro-alkoxy, high temperature (PFAH)	90°C: dry and damp locations 200 and 250 °C: dry locations - special applications
RHH	90 / 194	Thermoset rubber, heat resistant	Dry and damp locations
RHW / RHW-2	75 / 167 90 / 194	Thermoset rubber, moisture resistant	Dry and wet locations
SA	90 / 194 200 / 392	Silicone rubber	90°C: dry and damp locations 200°C: special applications
SIS	90 / 194	Thermoset	Switchboard wiring only
TBS	90 / 194	Thermoplastic with outer braid	Switchboard wiring only
TFE	250 / 482	Extruded polytetrafluoroethylene	Dry locations only

THHN	90 / 194	Thermoplastic, heat resistant, nylon jacket outer sheath	Dry and damp locations
THHW	75 / 167 90 / 194	Thermoplastic, heat and moisture resistant	75°C: wet locations 90°C: dry locations
THW / THW-2	75 / 167 90 / 194	Thermoplastic, heat and moisture resistant	THW - 75°C: wet loca ons 90°C: special applications (electric discharge lighting) THW-2 - dry and wet locations
THWN / THWN-2	75 / 167 90 / 194	Thermoplastic, moisture and heat resistant, nylon jacket outer sheath	Dry and wet locations
TW	60 / 140	Thermoplastic, moisture resistant	Dry and wet locations
UF	60 / 140 75 / 167	Underground feeder and branch circuit	Dry and wet locations (see Article 340.10 for provisions)
USE / USE-2	75 / 167 90 / 194	Underground service entrance cable	Dry and wet loca ons (see Ar cle 33 for provisions)
XHH	90 / 194	XLPE, heat resistant	Dry and damp locations
XHHW / XHHW-2	75 / 167 90 / 194	XLPE, heat and moisture resistant	XHHW - 75°C: wet loca ons, 90°C: dry and damp locations XHHW-2 - Dry and wet locations
Z	90 / 194 150 / 302	Modified ethylene tetrafluoroethylene	90°C: dry and damp locations 150°C: dry locations (special applications)
ZW / ZW-2	75 / 167 90 / 194 150 / 302	Modified ethylene tetrafluoroethylene, moisture resistant	ZW - 75°C: wet loca ons, 90°C: dry loca ons, 150°C: dry locations (special applications) ZW-2 - dry and wet locations

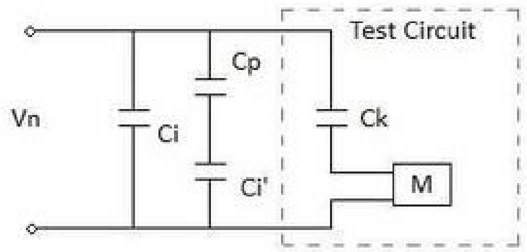
Partial Discharge

A partial discharge, as defined by IEC 60270, is a "localized electrical discharges that only partially bridge the insulation between conductors and which can or cannot occur adjacent to conductors". In other words, it is a partial breakdown in the insulation between two active conductors.

Partial discharges can occur in any location where the local electrical field strength is sufficient to breakdown that portion of the dielectric material (whether it be a deteriorated piece of insulation or an air cavity). The discharges generally appear as pulses with a typical duration of less than 1us. While very short in duration, the energy present in the discharge can interact with the surrounding dielectric material resulting in further insulation degradation and eventually if left unchecked, insulation failure.

Partial Discharge Testing

Partial discharge testing can detect the presence and location of partial discharge activity in electrical equipment. Suppose a piece of electrical equipment has a small air cavity in its insulation due to prolonged degradation and the cavity is subject to partial discharge. We want to test for partial discharge and so we connect a set of coupling capacitors in parallel to measure the charges caused by the partial discharge.



Partial discharge equivalent circuit with test circuit

The figure right shows a simplified equivalent circuit combined with a typical test circuit (as suggested in IEC 60270). The circuit elements are as follows:

- Vn is the voltage source
- Ci is the capacitance of the insulation system
- Cp is the capacitance of an air cavity in the insulation due to degradation
- Ci' is the capacitance of the rest of the insulation around the air cavity
- Ck is the capacitance of the coupling capacitor
- M is the measuring system hooked up in series

At some inception voltage, the electromagnetic field is strong enough to bridge the air cavity in the insulation and a partial discharge occurs. After the breakdown of the air gap, the rest of the insulation around the cavity (Ci) now sees the full voltage Vn and therefore the charge across Ci' increases.

This extra charge must be provided by all of the parallel capacitances around it (e.g. in this model Ci and Ck) or the voltage source (though it is usually too slow to react). So in a typical situation, the capacitances Ci and Ck discharge a short pulse into Ci' to provide the extra charge. However doing so reduces the voltage across all the capacitances and the voltage source Vn reacts by charging all of the capacitances in the system (including the air cavity) back to the normal voltage Vn.

Partial discharge testing is done by directly measuring the short pulse discharged into Ci' by the coupling capacitor Ck. In the equivalent circuit, the measuring system is represented by a single box M, but in practice, this includes the coupling device, connecting cables, measuring device, etc.

Now it's clear that any pulse measured by the measuring system **is not** the actual partial discharge, but an **apparent charge** caused by the real partial discharge (i.e. because the coupling capacitor Ck has to help provide the extra charge for Ci'). It's not possible to directly measure the partial discharge, but the apparent charges can be used to infer the level of partial discharge activity in the insulation system.

Test Circuit Calibration

Because only the apparent charges can be measured, it is important that the test circuit is properly calibrated. During calibration, a pulse of known magnitude is delivered into the system to simulate a partial discharge. The measuring system is then monitored to ensure that the test pulses are captured. The calibration process is done so that pulses with magnitudes of interest (i.e. that will damage the system) are reliably captured. A scaling factor can also be inferred based on the calibration tests.

References

1) IEC 60270 (2000) "High Voltage Test Techniques - Partial Discharge Measurements"

2) IEEE 400 (2001) "IEEE Guide for Field Tes ng and Evaluation of the Insulation of Shielded Power Cable Systems"

3) IEEE 1434 (2000) "IEEE Trial-Use Guide to the Measurement of Partial Discharges in Rotating Machinery"

Remote Earth

From Open Electrical

Jump to: navigation, search

Remote earth is a concept used to describe the resistance between one point in earth and an arbitrarily distant point (also in earth). The earth resistance between any two points typically increases proportional to the distance, however there comes a point after which the earth resistance no longer increases appreciably. Any point greater than this minimum distance is therefore referred to as remote earth.

For example, if the earth resistance is measured from a 10ft (~4.5m) earthing electrode, remote earth is typically any point further than 25ft (~11.4m) away.

Subsea Power Cable

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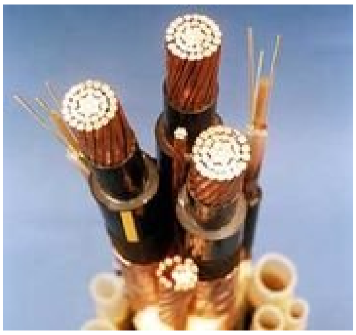


Composite subsea power and fiber optic cable

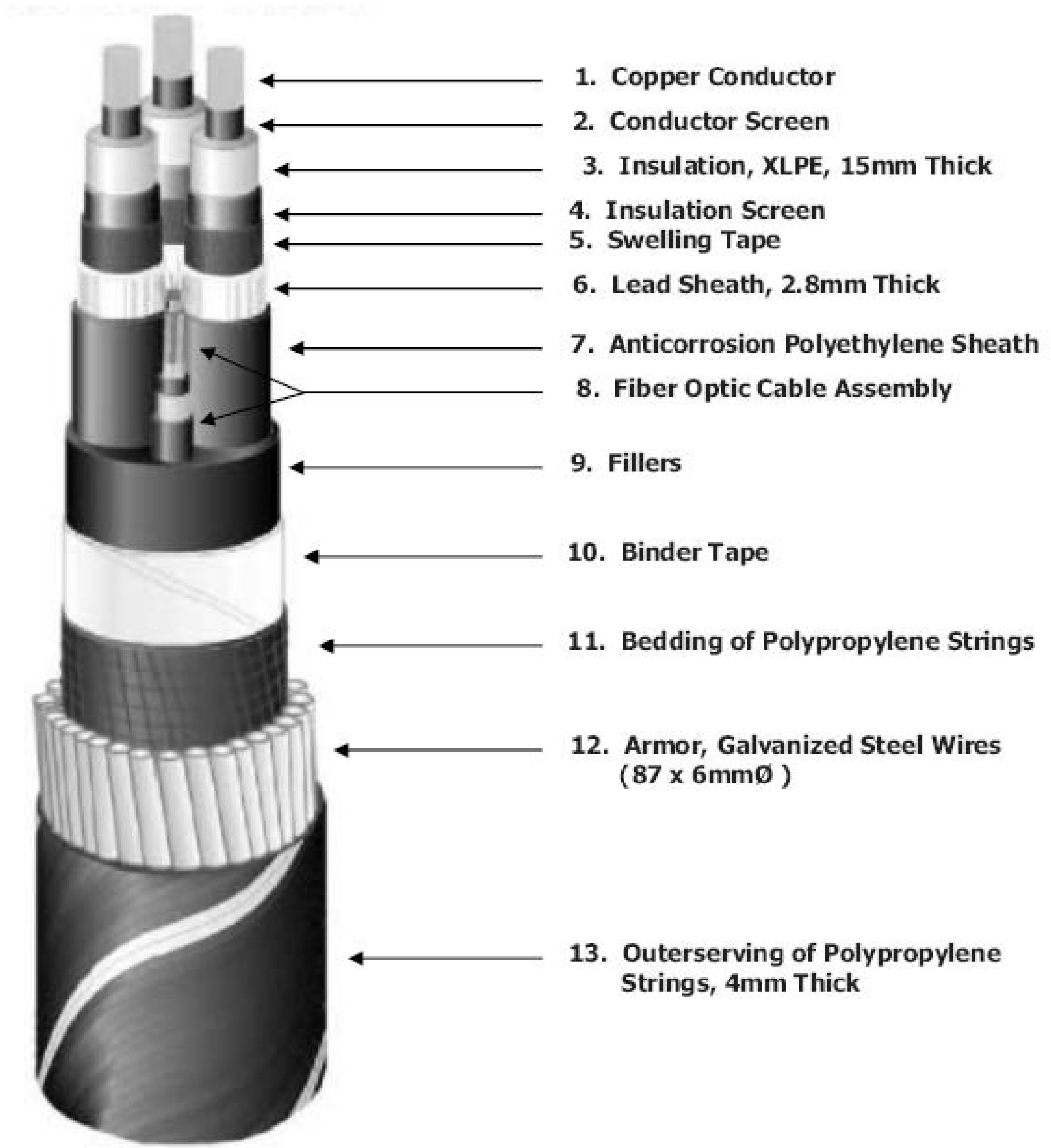
Subsea cables (or umbilicals) have been in use since the mid-19th century, initially for telegraphic communications (including the pioneering 1858 transatlantic telegraph cable), and later for power transmission.

The development of subsea power cables has been primarily driven by the HV power transmission and offshore oil and gas industries. One of the early major installations was a 138kV gas-filled cable run 25.3km from the British Columbia mainland to Vancouver Island (183m water depth) in 1958.

Subsea cables for oil and gas applications are typically composites, comprising multiple components such as HV/LV power cores, fiber optic bundles, hydraulic or instrument air hoses, etc. This article mainly deals with composite HV power and fiber-optic communications cables in offshore oil and gas applications. For this reason, the focus is on solid polymeric insulated cables, and oil-filled, gas-filled and paper insulated cables are not discussed.

Subsea Cable Design

There are many ways to manufacture a cable, and there is no standard design to which all vendors will necessarily adhere. However, composite subsea power and fibre optic cables will more or less be constructed with a combination of the following typical components (listed below from the inside out).



Power Conductors

Power conductors are typically high-conductivity stranded annealed copper. Actually this is a requirement of ISO 13628-5.

Conductor Screen (for HV cables)

The conductors are screened with an extruded semi-conducting tape to maintain a uniform electric field and minimize electrostatic stresses.

Insulation

The conductor insulation for solid polymeric cables are normally thermosetting materials, eg. XLPE or EPR.

Insulation Screen (for HV cables)

The insulation screen is typically an extruded semi-conducting material and has a similar function as the conductor screen (ie. control of the electric field).

Water Blocking Tape

Usually a helically wrapped swelling tape that serves as a longitudinal water and moisture barrier for the conductors

Conductor Sheath (for HV cables)

A conductive sheath / shield, typically of copper tape or sometimes lead alloy, is used to provide a path for fault and leakage currents (sheaths are earthed at one cable end). Lead sheaths are heavier and potentially more difficult to terminate than copper tape, but generally provide better earth fault capacity and water blocking.

Anti-Corrosion Sheath

A jacket over each insulated and sheathed conductor, typically of extruded polyethylene, is used to provide an impermeable barrier against water for corrosion protection of the metallic conductor sheath. The anti-corrosion sheath can also be extruded over the binder tape as opposed to over each individual conductor.

Filler

The interstices of the sub-bundle (ie. comprising power conductors, fibre optic bundle, hoses, etc) are normally filled with a soft polymer material such as polypropylene string or polyethylene.

Binder Tape

The binder tape is applied helically over the sub-bundle (ie. comprising power conductors, fibre optic bundle, hoses, etc) to "maintain stability after laying up of the sub-components" (ISO 13268-5 Clause 9.10).

Anti-Teredo Protection

One or more layers of copper or brass tape is applied over the taped bundle to protect against boring marine organisms such as the teredo (shipworm), pholads (mollusc) and limnoria (crustacean).

Note that anti-teredo protection is not shown on the typical cable arrangement diagram above.

Inner Sheath / Bedding

An inner sheath, typically a polymer like polypropylene or polyethylene, is applied over the taped bundle for "mechanical protection, bundle stability and to provide a bedding for the armour" (ISO 13268-5 Clause 9.11). For armoured cables, the inner sheath is a requirement of ISO 13268-5.

Continuously extruded thermoplastic (eg. polyethylene) in lieu of roving is required for dynamic applications.

Armour

One or more helically wrapped layers of armour wiring, usually of galvanised steel, provides mechanical protection and substantial weight for bottom stability. Cables that need to be torque balanced or require acceptance of high tensile loading can comprise two layers of contra-helically armouring (ie. wrapped in opposite directions). Contra-helical double wire armour cables cannot be coiled and it is necessary to use either a turntable or a drum.

Corrosion-resistant coatings can be applied on the steel wire armour to improve corrosion resistance characteristics. Stainless steel is not typically used, in part because of the potential for low oxygen levels in water (stainless steel depends on a self-repairing oxide coating for corrosion resistance).

Outer Sheath / Serving

Typically either a continuously extruded polymer sheath (such as polyethylene), or a covering of helically applied string rovings (such as polypropylene yarn)

Continuously extruded thermoplastic (e.g. polyethylene) is required for dynamic applications.

Cable Design Considerations

Lay

The lay of a cable describes the manner in which the conductors, fibre optic bundles, hoses, tubes, etc in a cable are laid in a helix to form the sub-bundle. The terminology arises from the manufacture of fibre and wire ropes. Right hand lay refers to the strands appearing to turn in a clockwise direction, or like a right-hand thread, when looking at the cable as it points away. Vice versa for left hand lay.

Choice in the direction of lay is important in the drumming operation, and the incorrect choice in both cable lay and drum rotation can lead to torque build-up potentially causing spooling problems and damage to the cable.

Bottom Stability

Cables that are subject to movement on the seabed as a result of tidal currents face the prospect of abrasion damage, and premature failure. The submerged cable must have sufficient weight to resist the maximum tidal seabed currents expected, even under extreme storm conditions.

Calculations for bottom stability are typically performed to DNV RP E305, “On-Bottom Stability Design of Submarine Pipelines”, and require metocean data from the prospective installation site.

Torque Balancing

“When a single wire armoured cable is suspended from the bow sheave of the laying vessel, a high proportion of the tensile load is carried by the helically applied armour wires. This loading produces a torque in the armour wires which, unless appropriate precautions are taken in the design of the cable, tends to cause the cable to twist so that the lay of the armour wires straightens towards the axis of the cable, and thereby transfers strain to the core(s).

The twisting action cannot pass backwards through the brakes of the cable laying gear to the cable yet to be laid, nor forward to the cable already laid on the seabed. The twisting action therefore tends to concentrate in the suspended cable between the bow sheave and the seabed. The problems become more severe with increasing immersed weight per unit length and increasing depth of laying.

The twisting action can be nullified by applying a second layer of armour wires, which under tensile loading conditions produces an equal and opposite torque to that of the inner layer of wires." [1].

Jacketed and Free-Flooded Designs

In a jacketed design, an extruded sheath over the sub-bundle is used to form a pressure-restricted barrier preventing water penetration into the sub-bundle / core. The jacket wall needs to be of sufficient thickness to withstand the water pressure when immersed.

In a free-flooded design, water is free to migrate into the interstices of the sub-bundle and fill the internal voids of the cable. In a free-flooded design, the individual sub-components (eg. conductors, fibre-optics, etc) will require suitable water blocking tapes and jackets, which will likely increase weight and diameter. Also, subsea termination of a free-flooded cable may be more difficult.

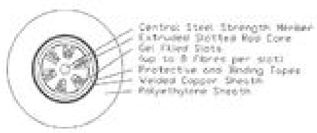
J-Tube Installation

For cables that are intended to be installed in J-tubes, consideration should be taken regarding the J-tube diameter, radius of curvature and lead-in angle. The radius of the J-tube needs to be below the minimum bending radii specified by the cable manufacturer. A smaller lead-in angle will aid in installation and pull-in. The diameter of the J-tube needs to accommodate the cross-sectional area of the cable as it is pulled through.

Fibre Optic Design

Like the power conductors, there are several ways to design a fibre optic bundle. Two common methods for packaging up fibres are as follows:

Slotted Core Design



Composite subsea power and fibre optic cable

The slotted core design consists of an extruded cylindrical slotted core, with the optical fibres set into the helical slots. The fibres are usually encapsulated in gel for support and to prevent longitudinal water propagation if the cable is severed.

Binder tape is helically wrapped around the core for protection and support. A metallic sheath provides protection against water and gas, and an extruded polymer oversheath provides further mechanical protection and a measure of corrosion protection.

Tube Design

In a tube design, the fibres are encapsulated in gel (for water ingress protection) inside a stainless steel tube (for mechanical and strain protection). The tube is usually armoured, with an extruded polymer oversheath applied over the armour.

Installation

There are a number of stages involved in the installation of a subsea cable, from site surveying to termination. ISO 13628-5 Section 15 has a good outline of the requirements for the general cable installation operation. Refer also to the paper by Hosseini et al [2], which gives a detailed account of a subsea cable installation in the South Pars gas field (Persian Gulf).

Site Survey

A site survey is conducted pre-installation, with consideration to the following (largely summarized from ISO 13628-5):

- Surveillance of the planned cable lay route (using a side-scan sonar or ROV)
- Bathymetric sub-bottom profiler and side-scan sonar survey of the proposed route
- Confirmation of the position of seabed obstructions (pipelines, cable and other structures)
- Identifying the location of any debris along the proposed corridor and removing the debris (if possible) before installation
- Identification of any deviations from the proposed route
- Survey the host facilities, including the J-tubes / I-tubes and the area for topside termination
- Deployment of temporary installation aids as necessary
- Deployment of transponders or beacons at critical positions (eg. subsea crossings)
- Longitudinal profile, seabed conditions and water depth along the proposed route length

Cable Laying Vessel

The cable laying vessel employed for composite subsea cable laying operations are selected to suit the application. In general, there is little crossover between cable laying vessels designed for handling subsea telecommunications cables and power cables. Features to consider when selecting a cable laying vessel (from Electric Cables Handbook [1]):

- Suitable hold dimensions for the storage of cable coils, drums or a turntable
- Suitability of the deck layout for fitting cable handling equipment
- Overall dimensions including minimum operating draft
- Adequate maneuverability
- Navigational and communications equipment and facilities for fitting additional items as necessary
- Power supplies available for additional equipment
- Accommodation and messing facilities and space for fitting temporary additions if necessary
- Age and general condition of the vessel such that specially constructed items may be of use for future operations
- Charter terms and conditions

ISO 13628-5 Section 15.2 outlines the requirements for the cable laying vessel and equipment, which shall include:

- Communications facilities
- Navigation and position systems
- Lay chutes, of a size that will avoid infringement of the minimum bend radius of the umbilical
- Conveyor systems to move the umbilical without the presence of uncontrolled spans or the possibility of the umbilical coming into contact with surfaces other than those of the handling and storage systems
- Cable engines
- Powered / unpowered sheaves
- Trenching / burial equipment
- ROV spread
- Diving spread
- Tension-measuring equipment to continuously monitor and record the tension to which the umbilical is subjected (plus alarms).
- Length measuring system
- Departure angle measuring equipment to continuously monitor the angle at which the umbilical leaves the vessel (plus alarms)
- Umbilical functional testing equipment
- Installation aids
- Device to cut the umbilical, and holding clamps, in case of emergency

Maersk Defender Cable Laying Vessel

Cable Laying

The cable laying operation is typically scheduled during an adequate window of predicted favorable weather conditions so that the full cable lay can be completed in one uninterrupted operation.

ISO 13628-5 Section 15.7 describes the mechanical handling requirements for the main cable lay, which is to avoid:

- Introduction of excessive slack in the vicinity of the touch-down position, by virtue of low tension/large departure angle, to preclude the possibility of loop formation
- Infringing the minimum bend radius at the touch-down point
- Introduction of large rates of twist into the umbilical, to reduce the probability of loop formation and bird-caging
- Application of excess tension, which may overstress the umbilical
- Flexing the umbilical, close to the over boarding point, where catenaries loads are at their maximum, and at the touch-down point for extended periods to exclude the likelihood of fatigue failures of the umbilical structure

Laying tension, cable length, and departure angle are monitored and controlled throughout the laying operation. Touch-down positions are visually monitored by ROV to verify that the cable is being laid within the proposed corridor.

What not to do – A YouTube video of a subsea cable reel going out of control.

Seabed Obstructions

There may be a need for subsea cables to cross seabed obstructions, especially in areas that are congested with subsea pipelines and other cables. Methods for subsea crossings of seabed obstructions include:

- Concrete mattresses to support cable over obstructions
- Use of protective cable sleeves (such as Uraduct) over the obstruction

J-Tube / I-Tube Pull-in Operations

The requirements for the installation of the subsea cable at the host facility through a J-tube / I-tube are described in ISO 13628-5 Section 15.4. In summary, the process is typically as follows:

- Preparatory work, including review of installation calculations, pigging of the J-tube / I-tube and installation of the messenger wire in the J-tube / I-tube
- Recovery of the messenger wire at the host facility and cable lay vessel
- Over boarding of cable pull-in head and vessel positioning to enable entry of cable into the J-tube / I-tube bellmouth at correct angle
- Pulling-in of cable through J-tube and I-tube to relevant deck level
- Securing of cable on J-tube / I-tube, either with a permanent hang-off or a temporary fastening arrangement (employed when time is critical and testing / cable lay is to proceed without additional delays)
- Sealing of J-tube / I-tube (optional) for corrosion protection, along with chemical protection such as chemical inhibitors, biocides and oxygen scavengers.

The termination of the cable to a topsides termination panel, or via an in-line splice, can be completed at any time after the cable is secured with a permanent hang-off arrangement.

Design Standards

The following standards are relevant for the design and installation of subsea cables:

- ISO 13628-5, “Petroleum and natural gas industries – Design and operation of subsea production systems – Part 5: Subsea umbilicals”
- DNV RP E305, “On-Bottom Stability Design of Submarine Pipelines”.
- IEC 60502, “Power Cables with Extruded Insula on and Their Accessories for Rated Voltages from 1 kV (Um = 1,2 kV) up to 30 kV (Um = 36 kV) - Part 2: Cables for Rated Voltages from 6 kV (Um = 7,2 kV) and up to 30 kV (Um = 36 kV)”
- CIGRE Electra No. 68 “Recommenda ons for Mechanical Tests on Submarine Cables”
- IEEE STD 1120, "IEEE Guide for the Planning, Design, Installa on and Repair of Submarine Power Cable Systems"

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1. McAllister, D. “Electric Cables Handbook”, Granada Publishing, 1982
2. Hosseini. M.K.A., Ramezzani, M. T. and Banae, M., “Submarine Cable Installation between Production Platform and Satellite Wellhead Platform of South Pars Gas Field – Phase 1 in the Persian Gulf”, OCEANS ’04, IEEE, November 2004
3. A wood, J.R., “Cable Design for Subsea Power Links”, IEEE Power Engineering Review, September 2000

Symmetrical Components

Symmetrical components is a mathematical method for representing an unbalanced set of phasors into three decoupled (independent) sets of phasors - two balanced sets and a third set with identical phasors. The method was originally developed in 1918 by Charles LeGeyt Fortescue and simplifies the analysis of unbalanced polyphase systems (e.g. commonly used for three-phase voltage, current and impedance phasors).

Wikipedia has a reasonably good exposition on symmetrical components, or for the original paper, click on the reference link below.

References

1. Charles L. Fortescue, "Method of Symmetrical Co-Ordinates Applied to the Solution of Polyphase Networks". Presented at the 34th annual convention of the AIEE (American Institute of Electrical Engineers) in Atlantic City, N.J. on 28 July 1918

VSD Cable

The use of fast switching circuitry in variable speed (or frequency) drives result in output waveforms with higher levels of harmonic components. These harmonics can cause:

- High electromagnetic interference (EMI) - where the cable is the antenna and the radiated EMI from the cable can induce voltages and currents on nearby cables and electrical equipment. This can especially be a problem when EMI causes noise and crosstalk in control and instrumentation cables.

- High earth currents - due to harmonics causing unbalances in the three-phase output. A portion of the unbalanced currents return to the source (i.e. inverter) via the earth conductor.

Therefore, VSD cables often have the following special characteristics:

- Heavy duty screen - usually copper, applied over the entire cable bundle to reduce EMI
- Three earth conductors - located symmetrically in the cable cross-section so that the phase-to-earth distance is identical for each phase, and the cable is "electrically balanced". Sometimes you'll see the designa on "3C + 3E"- this isn't a mistake!
- Larger earth conductors - to further reduce the impedance of the earth conductor return path and therefore reduce earth currents
- Robust insulation grades - such as XLPE is commonly used over PVC, so that the cable can better withstand transient voltage spikes