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FUNCTIONAL SPECIFICATION AND EVALUATION OF SUBSTATIONS

Working Group
B3.01
Task Forces 1 & 2

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Functional Specification and Evaluation of Substations

Prepared by Working Group B3.01 Task Forces 1 & 2

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Functional Specification and Evaluation of Substations

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Summary

Liberalisation of energy markets has led to new requirements from Asset Owners for high voltage substations. New concepts and solutions have been developed by Solution Providers. In response to this challenge Working Group B3.01 set up two Task Forces to find ways of dealing with this. Task Force 1 has investigated Functional Specifications whilst Task Force 2 has looked at effective ways of evaluating substations, both for conventional solutions and solutions involving innovative concepts. The results of the work of these Task Forces are published in this Technical Brochure.

The conclusions of Task Force 1 are that it is feasible to produce a functional specification based on defining the Boundaries to be complied with, the functional requirements in terms of transfer requirements and availability, a viable evaluation process based upon Life Cycle costs and some supplementary clauses to the commercial conditions. However, the work indicated several problem areas which indicate that Functional Specifications in this format are unlikely to be commonly applied at present, but it is believed that many aspects of the work will be of value to engineers working in this field. However some parts of the functional specification concept can already be used today, for example evaluating the availability of different proposed solutions in the purchasing process or perhaps in encouraging functional thinking.

The main conclusion of the work of Task Force 2 is that there is no best solution for all different requirements. The basis for finding the best solution is the sound definition of requirements and the cooperation between Asset Owners and full scale Solution Providers to optimise developed solutions. This combined economical and qualitative evaluation supports the solution-optimisation and when combined with sensitivity analysis provides a powerful tool for successful decision making.

1. Introduction

1.1 General Introduction

Due to the liberalisation of the energy market, the electricity transmission and distribution business is changing rapidly. Grid owners and utilities (Asset Owners) require solutions with high overall economic value. Manufacturers, contractors and engineering companies (Solution Providers) offer various innovative substation concepts.[Wahl96][Nbrg98]. It was considered by Working Group B3.01 Substation Concepts that the present way of specifying substations and evaluating tenders was not able to adequately respond to innovative solutions and may even be impeding the introduction of innovation. In 1999 two Task Forces were established to address this situation.

The first Task Force (Task Force 1) was to investigate the implementation of Functional Specifications. In the past in order to standardise his substation solutions, the Asset Owner defined many other requirements in detailed specifications for the specific plant. In order to achieve the significant cost benefits of innovation it is necessary to change from detailed specifications to Functional Specifications. The objective was to produce a standard format for the production of Functional Specifications to assist both Asset Owners and Solution Providers, when specifying and responding to the requirements for a specific substation. The Functional Specification needed to include all the necessary information for the Solution Provider to supply the optimum substation to meet the customers' present and future requirements.

The second Task Force (Task Force 2) was to investigate ways of evaluating substation solutions to enable Asset Owners or Solution Providers to compare different solutions, including innovative ideas, whether these solutions had been submitted in response to a Functional specification or to conventional specifications.

1.2 Functional Specifications

1.2.1 Background

Over the last few years manufacturers, contractors and engineering companies (later: Solution Providers) have developed a number of innovative solutions for substation design. Presently the Asset Owner or asset manager predetermines the availability, maintainability, flexibility and extendibility aspects of a substation. This is done, for example, by requiring a certain type of primary single line diagram and by positioning accurately the different parts of the substation and even different high voltage equipment in layout drawings. In order to standardise his substation solutions, the Asset Owner also defines many of other requirements in detailed specifications for the specific plant (Refer to fig. 1). One reason for using a detailed specification is the fact that this way the Asset Owner can be sure that he will get what he wants.

This approach inherently preserves the old designs and effectively slows the introduction of innovative substation solutions. However, it is also in the Asset Owners' interest to get better solutions together with minimised life cycle costs. In order to achieve the significant cost benefits of innovation it is necessary to change from detailed specifications to functional specifications (As indicated in fig. 2).

Functional specifications seem to be most powerful if projects are ordered on a turnkey basis. Only then can the Solution Providers do the whole cost optimisation including engineering, installation and construction work. Turnkey substation projects have in fact become more common even when using detailed specifications. A bid competition for a complete turnkey substation project has very often meant lower investment costs and shorter implementation time. These savings are expected to be achieved by reducing contract administration to a single substation supplier rather than managing several individual contracts for procurement of discrete components and other services. Furthermore, this outsourcing of engineering design and construction services has resulted in the Solution Provider taking care of the co-ordination between the different types of equipment included. This has lead to a dramatic reduction in the population of the grid Asset Owners' internal engineering resources.

In many countries the deregulation of electricity markets has also meant that there are new players in the market. The independent power producers, who often have very little internal expertise in transmission assets, have frequently introduced very tight time schedules for the projects. In these cases turnkey projects are virtually the only possibility, due to the lack of expertise on the part of the Asset Owner and the limited amount of time available. Also the deregulation process has forced short planning and construction times in almost all substation projects. In some cases consumers and producers do not disclose their investment proposals until a final investment decision has been reached.

There are also some problems with the principle of a functional specification, which must be solved before this kind of specification can be utilized. One concern lies with defining a method for the evaluation of the different solutions derived from the functional specification. This evaluation of very different solutions employing new technologies is more complicated than in the conventional case. A second concern is the lack of sufficient time both in the quotation phase for complex studies into the availability and flexibility to obtain the different solutions, and in the evaluation of the proposed alternative solutions when the project evaluation and execution lead times are considerably reduced. To help to speed up this process some guidelines are essential. Most conventional busbar systems have been developed over many years and Asset Owners are well aware of the extendibility and availability. Furthermore, the standardisation of busbar schemes and switchgear layouts has contributed to reducing the risk of human error during maintenance and switching operations. To incorporate these requirements, considerable rethinking of the specification of the substation availability and flexibility is necessary. Also, the substation requirements often change over the lifetime of the station and it is difficult to predict these future needs at the time the specification is written. Nevertheless, it is important to define the required flexibility in design within the functional specification.

With the implementation of “functional specifications” Asset Owners must rely more heavily on “Solution Providers” for technical substation solutions and consider new concepts with an open mind. The functional specification should also include long term penalty/bonus schemes for the substations performance against guaranteed availability measures. The functional specification should also be flexible in that implementation of future substation extensions are not restricted to the designs and protocols of the original solution provider. In essence this philosophy enables/facilitates competition for future extension works. On the other hand the commercial terms must explain what happens with the performance guarantee if the substation is extended during the guarantee period by a Solution Provider different from the one initially building the substation.

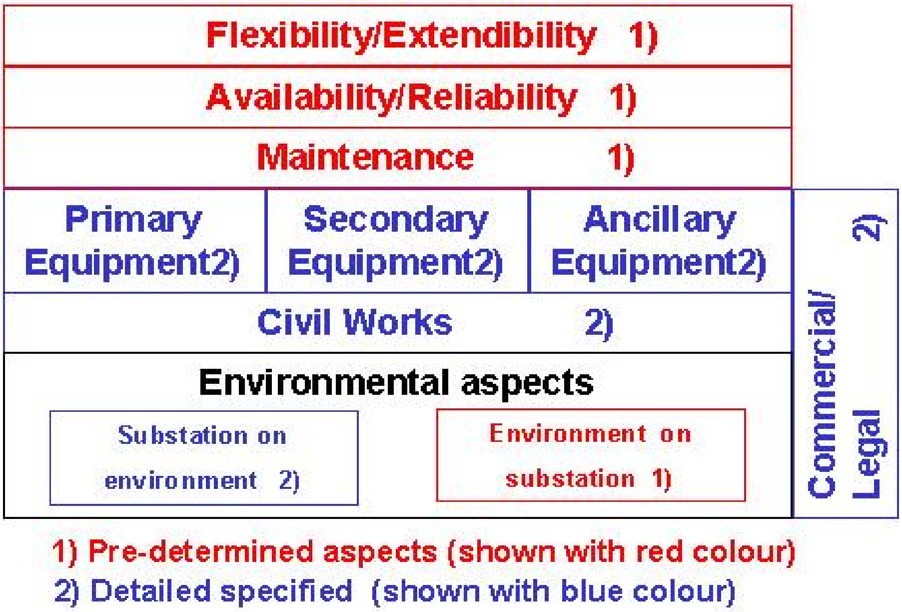

Fig. 1 Existing principles for specifying S/S

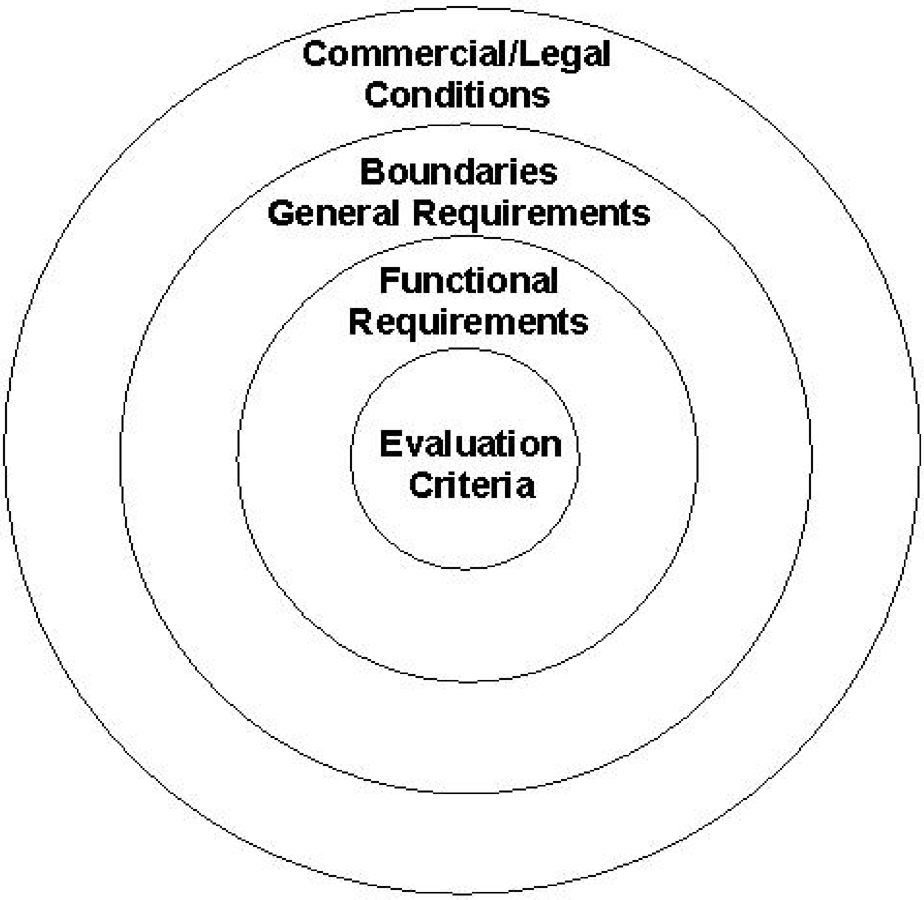

Fig. 2 Proposed functional specification

1.2.2 Scope

The objective is to produce a standard format for a functional specification, which can be used as a guide for Asset Owners, when specifying their requirements for a specific substation. The functional specification should include all the necessary information for the Solution Provider to supply the optimum substation, which meets the customers' present and future requirements.

As a first step the functional specification will be made only for a turnkey substation on a greenfield site. This is to minimise the interfaces to existing installations enabling attention to be concentrated on the basic principle of a functional specification.

1.2.3 Format for a Functional Specification

When starting to prepare a functional specification it is essential to consider what are the essential aspects which must be included in order to clearly define the current and future needs of the substation. Although the specification is to define the functional requirements of the new substation it must be remembered that this substation has to fit into an existing network, be connected to incoming and outgoing circuits as well as considering the environmental and legal aspects. These aspects we can consider as **Boundaries** to the new substation and these must be clearly defined in the functional specification. For example, boundaries may include high voltage terminal points, environmental aspects, spatial constraints, civil information, the laws, grid code and standards to be followed, safety regulations and other basic system parameters.

The **Functional Requirements** of a particular substation define the actual and future needs of the Asset Owner. These needs include the required capacity and availability, which will be subject to penalty/bonus schemes together with requirements for flexibility and future extendibility. The substation can be considered as a box with a number of input and output nodes or connection points. The Asset Owner has to define the connectivity required between these nodes and the capacity of power transfer required with its associated availability.

With any specification or Contract Documents there are a set of **Commercial Conditions**. With a Functional Specification certain special commercial conditions will be required which are not normally included in a conventional contract. In this document these special conditions are considered and defined.

When solution providers are allowed more freedom in their tender preparation, the asset owners must state clearly in the functional specification how the tenders will be evaluated, as is frequently currently required by the competition legislation of public procurement. The evaluation of tenders based on functional requirements is also made more complicated as the solutions may differ from each other more than with the previous detailed conventional designs. In order to evaluate each solution,

Evaluation Criteria and weighting factors need to take into account the running, operating and maintenance costs. This is most likely to be achieved in financial terms by considering the Life Cycle Cost (LCC) together with weighting factors for flexibility, extendibility and availability. The factors to be used in this LCC for evaluating the bids need to be defined by the Asset Owner to ensure that they correctly reflect the importance that he attaches to each aspect. Consequently an evaluation formula is created which enables both the Solution Provider and the Asset Owner to calculate the evaluated cost of the substation. This is important for the Solution Provider to enable him to compare different solutions which he may be considering and then choose the one which gives the lowest evaluated cost for this particular Asset Owner thus making his offer attractive.

It has therefore been decided that a functional specification should be divided into four parts: **Boundaries, Functional Requirements, Commercial Conditions and Evaluation Criteria**. In the following chapters a typical Proforma is developed for each of these parts of a typical Functional Specification

1.3 Evaluation of Substation Concepts

1.3.1 Situation

Due to the liberalisation of the energy market, the electricity transmission and distribution business is changing rapidly. Grid owners and utilities (Asset Owners) ask for solutions with high economic overall value. Manufacturers, contractors and engineering companies (Solution Providers) offer various innovative substation concepts. A questionnaire concerning aspects on planning, design, operation and maintenance of future substations shows: customer values are changing from technical to a more overall value with emphasis on economical and environmental values [cigre 00.1].

1.3.2 Scope

The aim is to develop a method to determine the overall lifetime value of a substation solution. This method should enable an economical, technical and environmental evaluation and support the decision for the most suitable solution under the given circumstances. This method intends to support the decisions of:

- *Asset Owners*: An instrument to measure the overall value of different existing or planned substation solutions.
- *Solution Providers*: An instrument to evaluate different solution concepts and select a solution that provides the highest overall value.
- *Research Institutions*: An instrument to evaluate new substation concepts and designs.

This method has to consider the planning, design, procurement, installation, commissioning, operation, maintenance, extension, refurbishment and/or decommissioning of a substation, in other words the whole life cycle of a substation.

2. Functional Specifications

2.1 Boundaries Proforma

As explained in the Introduction the Boundaries define the essential parameters to enable the substation to be co-ordinated into the existing network and the required location. There are eleven subsections of the Boundaries dealing with the different aspects.

2.1.1. Location and Spatial Constraints

The location of the site is at (Describe location and give northings and eastings of one corner of the site.)
The maximum available site area is sq.m
Maximum length in east/west direction is m
Maximum length in north/south direction is m
The site with its boundaries is shown on Drawing No. and this drawing also shows the three bench marks (if available) located on the site and the locations of each of the external circuit entries (current and future, if known). Each of these entries is dimensioned from the dimensioned corner of the site which in turn can be accurately located from the benchmarks (if available).
A bonus of $/sq.m reduction in the area used below that defined above shall be allowed in the evaluation of the tenders.
If the solution Provider wishes to relocate the circuit entries (which must remain in the same general direction) then he shall advise in his tender the proposed revised locations and the reasons and advantages of so doing.
The level of the site above the National Benchmark/sea level is generally and the changes in level across the site are shown in the site drawing referred to above.

2.1.2. Primary Circuit Terminal Points and Physical Boundaries

2.1.2.1 Overhead Lines (Repeat Data for each OHL Circuit)

Circuit Name:
Voltage:
Grid point location for centre of tower N E
For dimensions of tower refer to Drawing No.
If a double or multi circuit tower the circuit location on the tower should be clearly marked.
Orientation of tower centre line in direction of conductors is at degrees to the normal from the site boundary line.
Phasing for vertical formation is Top: Middle: Bottom:
Phasing for horizontal formation is Left: Middle: Right:
when viewed looking out to the line from the substation.
Stringing tension for span to substation gantry is:
Conductors for span to substation are:

Rated current of circuit is A (state also the conditions matching with the line)
Solution Provider shall supply suitable shackle points on landing structure.
Downdropper conductors are:
Solution Provider should provide suitable clamps on the substation equipment to land these downdroppers.
Earthwire on tower is single/double
Earthwire conductor is:
Solution Provider shall provide suitable points on the substation landing structure to land the earthwire(s).

2.1.2.2 Power Cables (Repeat data for each Power Cable Circuit)

Circuit Name:
Voltage:
Type of cable XLPE/LPOF etc.
Number of cables per phase:
Conductor size in sq. mm.:
Method of bonding applied on cable sheaths is single end/solid/cross bonded (If single end state at which end)
Solution Provider shall/ shall not provide suitable sealing ends to terminate the above-mentioned cables into the equipment within his supply.
Direction of approach of the cable circuit is shown on the site layout Drawing referred to above.
For oil filled cables the Solution Provider shall provide space and civil works for oil tanks as shown on Drawing No.
Pilot Cables laid with power cable No. off and type
No. of cores required in pilots for use of cable supplier:
Pilot marshalling cabinet to be provided by Cable supplier/Solution Provider

2.1.2.3 Auxiliary Supplies

Auxiliary LVAC supply is provided by the Asset Owner / Solution Provider.
Auxiliary Supply Voltage:
Rating per circuit kVA:
No. of circuits:
Cable type and number off:
Terminal point:
Termination kits to be/ not to be supplied by Solution Provider.
Glands and lugs to be/ not to be supplied by Solution Provider.
Tariff Metering for this supply to be provided by Solution Provider/ Others

2.1.3 Basic Information for Civil Works

The minimum ground bearing pressure is
The earth resistivity is
The thermal resistivity is
The existing water table is at a depth of

The full information is included in the Soil Investigation report No. attached together with full details of location of the individual boreholes.
The site shall be leveled/left sloping with gradient of
The finished site level shall be
The Solution Provider is/is not required to remove all spoil from the site to a suitable dumping area
The area for site facilities is within the site/in the area provided external to the site as shown on the site drawing
The Solution Provider is responsible for fencing and security of the site during construction
The interface with the access road to the site is at the site boundary/ at a point aa metres from the boundary and the Solution Provider is required to include this access road in his price.
The interface to the existing drainage system shall be at the site boundary/ at a distance of dd metres from the boundary and the Solution Provider shall provide this external drainage system in his price.
The interface for site water supplies shall be at the boundary of the site/at a distance of ww metres from the boundary and the Solution Provider shall include the external water connection in his price.
The common services building on the site shall include the following rooms as a minimum and the minimum dimensions for each room are shown where appropriate (client to detail as required)
The required finishes are detailed in the attached finishes schedule. (include if appropriate)
The locations of any buried services (water, electricity, gas etc.) are shown on the drawing xxxxxxx./ shall be determined by the Solution Provider.

2.1.4. Basic System Parameters (Repeat for each different Voltage in the Substation)

Nominal System Voltage	kV
System Highest Voltage	kV
Basic (LIWL) Impulse Level	kVp
Switching Impulse Level	kVp
Power frequency Test Voltage	kV
Short Circuit Level (3 phase)	kA
Short Circuit Level (1 phase)	kA
Short Time Current Duration	s
System Neutral Earthing Solid/Resistance/ Reactance/Petersen coil/ Ungrounded	
Earth fault factor, max. time	s
Substation Neutral Earthing for Star/Delta Winding Solid/Resistance/ Reactance/Petersen coil/ Ungrounded	
Frequency	Hz
Allowed Variation (+/-)	%

Phase Shift between voltage systems
With the HV system considered as 0 degrees (12 o’clock) the LV system shall be at xx degrees lagging/leading (y o’clock).

2.1.5. Secondary System Aspects

2.1.5.1 Control Centres

The substantion control system is required to interface with the following remote control centres:

District Control centre: Yes/No
Location:
Existing control equipment manufacturer and type
Mimic Diagram exists Yes/No
Modification of software and mimic diagram to be included/excluded from contract
Protocol used:
Software version:

National Control Centre: Yes/No
Location:
Existing control equipment manufacturer and type:
Mimic Diagram exists Yes/No
Modification of software and mimic diagram to be included/excluded from contract
Protocol used:
Software version:

2.1.5.2 Protection

(If equipment already exists at the remote ends then the following information shall be provided. If new equipment is required at the remote end as part of this contract see Section 2.1.11)

The following protection devices exist at the remote ends of the overhead line circuits. Equipment provided at the substation must be compatible with and able to operate satisfactorily in conjunction with these existing equipments. Alternatively the Solution Provider may completely replace these protections with equipment supplied and installed by him to be compatible with the new equipment being supplied at the new substation.

Circuit Name:
First Main protection:
Second Main Protection:
Third Main Protection:
Back Up Protection:
Autoreclose Equipment
Intertripping Equipment:
Protection Signalling Equipment:
(Full details of each equipment should be given and this should be repeated for each overhead line circuit.)

The following protections exist at the remote ends of the cable circuits.
Equipment provided at the substation must be compatible with and able to operate satisfactorily in conjunction with these existing equipments. Alternatively the Solution Provider may completely replace these protections with equipment supplied and installed by him to be compatible with the new equipment being supplied at the new substation.

Circuit Name:
First Main protection:
Second Main Protection:
Third Main Protection:
Back Up Protection:
Intertripping Equipment:
Protection Signalling Equipment:
(Full details of each equipment should be given and this should be repeated for each overhead line circuit.)

2.1.5.3 Communications

The following methods of communication are available on the circuits as detailed below:

<u>Circuit Name</u>:

Power Line Carrier:	Yes/No
Phase to phase/Intercircuit coupling	
Line traps fitted at remote end	Yes/No
(If yes provide details)	
PLC equipment existing at remote end	Yes/No
(if existing, give details of type, bandwidth, frequency etc.)	
Microwave	Yes/No
(If yes give details of existing system)	
Fibre optic	Yes/No
(If yes give details of fibres, terminal point, jointing or junction box requirements, multiplexers included at remote end etc.)	
Pilot Cables	Yes/No
Private/Rented	
(If yes give details of pilots, terminal point, jointing or junction box requirements, isolation transformers etc.)	

The above is to be completed for each circuit.

2.1.6. Standards and Regulations

(In this section the client shall detail the standards he requires the Solution Provider to comply with for the system and all of the different types of equipment he anticipates the Solution Provider may use. In addition the client shall define in this Section all relevant laws, regulations and Safety Code requirements pertinent to the site.)

2.1.7. Effects of environment on substation

The client shall give the relevant maximum, minimum and average values of the following environmental conditions at Site:
Wind (in terms of wind speed or wind pressure)
Snow level
Soil frost
Temperature
Humidity
Rainfall
The client shall define the values of the following parameters which must be complied with for design at the site.
Ice (thickness of ice on conductors to be considered in design)
Seismic level (in terms of g value in each direction and frequency if applicable)
Pollution level (in accordance with IEC in kV /mm)
Keraunic level (thunderstorm days/yr)
Any other specific environmental requirements (e.g. flood level, sandstorms, etc.)

2.1.8. Effects of substation on environment

The client shall give the allowed maximum values for the following environmental conditions at Site:
Noise level (in terms of dBA and should clearly identify if sound pressure level or sound power level and measurement location)
Electric field (at ground level)
Magnetic field (in micro Tesla at specified boundary)
Corona level
Aesthetic restrictions (e.g. height, colour of porcelain etc.)
Style of building architectural constraints
Archaeological restraints (information on any possible archaeological artefacts)
Oil damage prevention (specific drainage and clean up requirements)
Laws (National and Local)
Regulations (other than laws which the client wishes to be applied on the specific site)

2.1.9. Safety requirements

The client shall state all the safety aspects to be taken into account in design, during construction, installation and testing at Site as well as for use, inspection, testing and maintenance of the substation in use:
Safety standards to be fulfilled
National Safety code
Safety regulations of the client
Step, touch and ground potential rise
Minimum clearances (The safety clearances should be the clearances required if access is required for maintenance purposes. If the equipment can be maintained by withdrawing to another area, clearances can be reduced

provided they comply with relevant IEC standards for phase to earth and phase to phase and are proved by impulse testing)
Restrictions on live working
Any other specific safety requirements (Substation security requirements, Substation lighting, etc.)

2.1.10. Constraints

(In this Section the client shall define any specific constraints he considers essential to be imposed upon the Solution Provider. These constraints should be kept to a minimum, however these may include restricting the ratings of certain key components to be used in the network to minimise spares holdings. Examples of this may be
Defining the full load current rating to be used for circuit breakers used at a particular voltage.
Defining the ratings and impedance to be used for transformers interconnecting between certain voltages. In the case of transformers it may also be necessary to define certain physical constraints such as spacing of phase centres, location of tertiary, basic foundation details to enable interchangeability with a National Spare transformer)

2.1.11 Work at Other Locations

(If there is no existing equipment at the remote end and the Asset Owner requires this providing as part of the contract)

The Solution Provider shall provide an additional bay of primary equipment to interface with the existing substation as shown on drawing No. xxxx and specification No. yyyy.

The Solution Provider shall supply and install new remote end protection devices compatible with the new equipment being supplied at the new substation.

2.2 Functional Requirements Proforma

This section is the essential definition of the functional requirements for the new substation which defines what the substation must be capable of doing.

2.2.1. Functional requirements

2.2.1.1 Power flow external and internal in substation

2.2.1.1.1 External power flow for all objects connected together (load case 1)

Electrical loads shall be specified at each primary connection point to the substation:

- normal load with direction MW, Mvar Import/Export
- maximum continuous load active and reactive together with direction MW, Mvar Import/Export
- maximum load for limited time active and reactive together with direction MW, Mvar Import/Export
- maximum and minimum operating (continuous) voltage level

2.2.1.1.2 External power flow for split operation (load case 2)

Electrical loads shall be specified at each primary connection point to the substation:

- normal load with direction MW, Mvar Import/Export
- maximum continuous load active and reactive together with direction MW, Mvar Import/Export
- maximum load for limited time active and reactive together with direction MW, Mvar Import/Export
- maximum and minimum operating (continuous) voltage level

Any additional load case(s) shall be added here.

2.2.1.2 Future extensions required and changes in power flow

Required future primary connections to switchgear have to be specified by the Asset Owner if known. If details are not known it could be assumed that details are similar to those of the initial stage.

Broad descriptions on how extensions can be carried out should be given by the Solution Provider. Necessary outages of existing bays should be specified including outage sequence and estimated outage times.

Future changes in power flow without any changes of HV primary connections have to be specified by Asset Owner. This is necessary for Solution Provider to leave space for future power transformers, dimension primary connections, etc.

Load conditions and directions of load flow are defined by load data and voltage levels at each external load point, see a) and b). Solution Provider thus can propose number and ratings of power transformers. If Asset Owner wants to rule split up of power transformers then this can be done by specifying suitable numbers of external connections.

2.2.1.3 Example for calculating availability and reliability

In the example shown in the figure below it is assumed that power transfer paths exist between all external connection points 1 to 5 during normal operation. It is assumed that 1, 2 and 3 are infeed points, and 4 and 5 are load points.

a) Load case 1
Load point 4: $U_{f4l1} < 0{,}1$ h/yr; $f_{f4l1} < 3$ /yr
Load point 5: $U_{f5l1} < 0{,}1$……..
Where U is unavailability, f is major failure rate and subscript f411 etc. is referring to node 4, xxxx and load case 1

Interruption at load point 4 results from simultaneous forced outages of all line bays 1-3 or the load bay 4 ((Bay1 AND Bay2 AND Bay3) OR Bay4)

Overlapping events

Load point 4 and 5: $U_{f4,5l1}$<_____;$f_{f4,5l1}$<_______

Interruption at load point 4 and 5 results from simultaneous forced outages of all line bays 1-3 or both load bays ((Bay1 AND Bay2 AND Bay3) OR (Bay 4 AND Bay5))

b) Load case 2
Load point 4: $U_{f\,4l2} < 0{,}2$; $f_{f4l2} < 7$
Load point 5: $U_{f\,5l2} < 0{,}3$ ……..

Interruption at load point 4 results from simultaneous forced outages of line bays 1 and 2 or load bay 4 ((Bay1 AND Bay2) OR Bay 4)
The same type of reliability figures must be given for each of the different load cases.

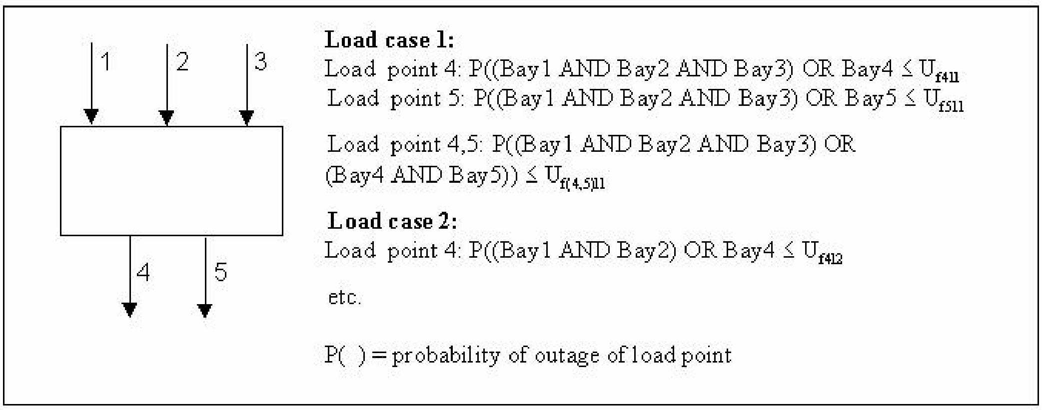

Fig. 3 Example of different load cases.

2.2.1.3.1 Availability

2.2.1.3.1.1 Reliability of external primary circuits (to be used as input for calculations)

This data refers to outages due to faults and outages due to preventive maintenance of the external primary circuits connected to the load points (terminals) of the substation.

Load points (terminals) and load cases are shown in Fig. 3.

(To be repeated for each circuit)
Circuit name: Feeder name (xx km long, total fault rate y fault/100 km*year, divided into permanent, transient and temporary as stated below)

Permanent forced	
outage rate:	number/yr
outage duration:	h/outage

Transient forced	
outage rate:	number /yr
outage duration:	sec/outage

Temporary forced	
outage rate:	number/yr
outage duration:	h/outage

Preventive maintenance	
interval:	yr
scheduled outage duration:	h each

2.2.1.3.1.2 Reliability of external Auxiliary Supplies (if provided by Asset Owner) (Repeat data for each supply)

The Asset Owner shall here state availability data of the auxiliary supplies.

Permanent forced	
outage rate:	number/yr
outage duration:	h/outage

Preventive maintenance	
interval:	yr
scheduled outage duration:	h each

2.2.1.3.2 Required target values to be fulfilled

Generic Requirements

The planned outages on any external connection point shall not require the shutdown of any other external connection point.
The switching configuration shall be designed such that any fault on one external connection point shall not cause the loss of any other external connection point. (A short term loss of another external connection point

for a maximum of xx seconds shall/shall not be acceptable to allow automatic switching to be performed. This short term outage period will, of course be taken into account in the calculation of unavailability for bonus/ penalty)
The bussing points within the substation shall be designed such that the planned and unplanned outages are included within the unavailability figures for each of the external connection points.
Any external connection points which cannot be taken out simultaneously must be defined so that the bussing points can be designed to ensure that this is achieved.
The effect of auxiliary supplies on the unavailability of all external connection points must be taken into account.
The maximum allowed outage of the auxiliary supply is also stated here.

(Any other generic requirements the Asset Owner wishes to add should be included here)

2.2.1.3.2.1Forced outages
The target values for unavailability and other reliability indices for external load points include only contributions originating inside the substation.

External Connection Point No: (Repeat data for all external connection point, Fig 3)

Target values
max. forced interruption frequency: number /yr
max. restoration time t_r (see footnote 1): h
Unavailability in hours/year can be calculated by multiplying the interruption frequency by the restoration time

2.2.1.3.2.2 Corrective maintenance outages
Regulations (national etc):
Declare all regulations regarding service restoration and switching actions (for example whether or not it is permissible to operate a disconnector remotely to change a particular switching arrangement without personal verification).

Logistic delay:
Give the delay for operational staff to go to the substation for switching actions etc. Possible additional time for switching action shall be declared.

Strategic spare parts:
Strategic spare parts are those that may be required to replace equipment or parts damaged as a result of a major failure. The Solution Provider shall provide all strategic spare parts individually priced but included within the fixed price for the substation. In some cases the Asset Owner may hold these spare parts (either themselves or through a pooling agreement with other partners) and specific spare parts may be deleted at

the individual prices quoted. In addition to the compliant offer for strategic spares the Solution Provider may offer an alternative method of ensuring the availability of the strategic spares from a stock held by him. In this case the guaranteed delivery time of the strategic spare to the site plus full commercial terms for this alternative scheme shall be defined.

2.2.1.3.2.3 Preventive maintenance outages

Maintenance conditions and restrictions
Maintenance work is only allowed to be done during the following time of the year:
From DD/MM to DD/MM.
Transformer group name: xx/yy kV
Maximum load on transformer group during maintenance work: XX MVA

Describe any other restrictions during maintenance works:

(Repeat data for each transformer group, i.e. all power transformers connected between the same two voltage levels.)

Target values
The target values are associated to preventive maintenance of equipment in the substation.

Name of Bay: (Repeat data for each bay, fig x)
Preventive maintenance
min. interval: yr (max. maintenance frequency = interval^{-1})
max. scheduled outage duration: hours per maintenance occasion

2.2.2 Transformation
2.2.2.1 Voltage Control
2.2.2.1.1 General
The transformation of power shall be equipped with on-load voltage regulating control for varying the effective voltage ratio during normal load situations but without changing the phase displacement.

If the voltage regulation causes impurities in the insulation media, the voltage regulation must be housed in a separate container. This is to prevent impurities spreading into the other insulation media of the power transformation.

Voltage regulation shall be physically located on xx kV side of the transformation.

2.2.2.1.2 Automatic Voltage Control
Voltage on xx kV voltage level shall be kept constant within ± y% of required voltage level from zero to full MVA-load through the transformation. This shall be possible for any feeding voltage between minimum and maximum.

The required voltage level to keep constant might be the level at a remote point in the xx kV system. The voltage control equipment thus shall have the necessary voltage drop compensation facility to make this possible.

Maximum voltage on xx kV side of transformation must be limited to maximum voltage level of system, i.e. voltage control must not raise voltage higher than this value even if voltage at remote point will be lower than required.

Voltage control shall normally be in automatic mode but it shall be possible from remote and local to change control to manual operating mode and thus make regulation by hand. It shall also be possible to change the voltage set point value from remote and local.

The voltage control equipment shall include, but not be limited to, the following as required:

- Range of setpoint adjustment ±x-y% of rated voltage.
- Undervoltage setting ±x-y% of transformer rated voltage, as required.
- Etc.

If there is more than one power transformation device supplied, necessary means should be provided to operate the voltage control in independent or parallel mode.

2.2.3 Secondary equipment

2.2.3.1 Protection

2.2.3.1.1 Fault clearance time

(Fault clearance times to be specified for each voltage level separately, where applicable)
All faults within the Substation shall be cleared by main protection within xxx milliseconds.
All faults on external circuits shall be cleared within xxx milliseconds for the first yy% of the circuit and within zzz milliseconds for the final (100 – yy)%. The additional time is allowed for protection signalling and intertrip.
(If the Asset Owner wishes to consider different times for different circuits depending on the magnitude of the fault current or other reason, then the times for the specific circuits should each be defined in the same format as above)

2.2.3.1.2 Redundancy (This clause to be added only when redundancy is required)
The failure of one main protection or an auxiliary component in the main protection system shall not cause the specified tripping time to be exceeded. The maloperation of any single protection relay or system shall not cause unnecessary tripping of any circuits.

2.2.3.1.3 Failure of Primary Fault clearing device

If a main protection has operated and the fault has not been cleared within the required time, another protection shall be provided to ensure that the fault is removed from the system within www milliseconds.

2.2.3.1.4 Stability and Sensitivity of Detection Required

All of the protection shall remain stable for faults outside of their protected zone for currents up to the maximum which can occur, based upon the system parameters defined in the Boundaries Section. Current detectors shall be dimensioned in such a way as to make this possible. All protections shall remain stable for external faults in the presence of capacitive charging currents.

All protections shall ensure that internal faults will be cleared under the minimum fault level conditions defined in the Boundaries Section.

For transformer and reactor electrical protections it is acknowledged that a small unprotected zone close to the neutral may occur. This unprotected zone shall not exceed uu% of the winding.

2.2.3.1.5 Back Up Requirements

In the event of failure of the main protection(s), a system of back up protection shall be provided. These shall ensure that all faults within the substation and within the maximum/minimum fault level range as defined in the Boundaries Section shall be cleared in less than BBBB milliseconds.

For primary faults in the adjacent substation and further external circuits remote back up protection shall be provided at the substation belonging to the delivery. These shall ensure that in the event of failure of the main protection(s) at the adjacent substations, faults at each of the adjacent station busbars shall be cleared from the system within bbbb milliseconds.

2.2.3.1.6 Ability to store fault records

One main protection on each circuit or bussing point shall be able to store analogue fault records. (This may not be required if analogue fault records are specified for the control system.) These fault records shall be capable of being downloaded at least locally at the relays by means of a laptop computer and/or remotely via the communications system.

2.2.3.1.7 Adjustable Settings

The main protection relays shall be capable of storing up to s number of separate groups of settings. This requirement shall apply to overhead line, cable, transformer, reactor, bussing point protection. (Delete or add protection devices as appropriate)

Switching from one group of settings to another shall be possible:

- Automatically (client to define circuits),
- Locally at the relay (client to define circuits)
- Remotely via the communications system. (Client to define circuits)

2.2.3.2 Special Features

2.2.3.2.1 Power Swing Stability

The protection systems shall/shall not operate for the occurrence of power swings on the network.

2.2.3.2.2 Autoreclose

On the occurrence of a fault, which may reasonably be assumed to be of a transient or temporary nature, the system shall automatically reclose the faulty circuit. Therefore, this shall be applied for the xxxx circuits and the dead time of yyy milliseconds.

If the initiating fault is a single phase fault and single-phase tripping is used then reclosure shall be on a high speed single phase basis.

If the fault is of a multiphase nature then the tripping and reclosure shall always be on a three phase basis.

If the circuit after reclosing remains in service for a period of r seconds then the autoreclose mechanism shall reset. If, however, the circuit trips within the period of r seconds from reclosure the auto reclose mechanism for that circuit shall lockout.

Or

In case of an immediate re-tripping after the high speed autoreclose a second delayed autoreclose shall be initiated and the breaker closed after ssss seconds.

If the circuit after this second reclosing remains in service for a period of r seconds then the autoreclose mechanism shall reset. If, however, the circuit trips within the period of r seconds from reclosure the auto reclose mechanism for that circuit shall lockout.

Auto reclose shall not be initiated for faults on circuits for which it is not reasonable to assume that the fault may be transitory, except as part of an auto isolation scheme.
If a protection for a part of the system, which may not be reasonably likely to have transient faults, operates at the same time as the protection which will initiate autoreclose then the autoreclose shall be blocked.
If a circuit is a composite combination of more than one isolatable section, then on the occurrence of a fault on one section, an auto isolation sequence shall be started, which will trip the total circuit and automatically isolate the faulty part of the circuit and restore the remaining healthy part to service.
(Possible other requirements concerning automatic reclosure shall be stated here)

2.2.3.2.3 Layout of Equipment to minimise risk of Human Error
The equipment shall be arranged in the enclosures and labelled in such a way as to reduce the risk of a person confusing the equipment associated with one circuit with that of another. In general equipment for different circuits shall be located within different enclosures, but where the quantity of equipment is such that this would be wasteful on space and steelwork, clear segregation within the common enclosure shall be employed. (The Asset Owner can add as many special functional requirements as he wishes in this Section)

2.2.3.2.4 Testing facilities
The equipment shall be easily tested for each protective function with standard testing devices and without causing erroneous tripping of breakers. All protection relays shall be provided with test switches making secondary testing possible with the primary object in full service and protected by the redundant or back up protection.

Test switches shall be designed in such a way that there is no risk of:
- inadvertent opening of CT-circuits
- spurious trip signals issued

when protection relays are shifted from service to test position or vice versa.
In order to fulfil the above requirement all test switch connections shall be made during design stage. No wiring whatsoever should be necessary during the routine testing of the protection relays.
Testing personnel shall only need to plug in a test handle in the test switch to get the correct sequence of opening trip circuits, short-circuiting CT-circuits, opening VT-circuits etc.

2.2.3.3 Control System
2.2.3.3.1 Control Functions
The control system to be provided shall provide control functions for the

following items:- (Delete or add additional as required)
Circuit Breakers
Disconnectors
Earth Switches
Tap Changer
Shunt reactor
Shunt Capacitor Bank
Protection In/Out Switching
Autoreclose In/Out Switching

Control for the following plant items:-
(Insert plant items here)
shall be done in a two step operation:

- 1st step shall "reserve" the chosen object and block operation of all other objects.
- 2nd step shall execute the chosen command.

Interlocking shall be provided by software or hardwired or both or neither (delete or modify as required)

2.2.3.3.2 Status Indication
The control system shall provide status indication monitoring for the following functions:- (Delete or add additional as appropriate)
Circuit Breakers
Disconnectors
Earth Switches
Tap Change Auto/Manual/Parallel/Independent
Shunt Reactor Control status
Capacitor Bank Control status
Protection/Autoreclose In or Out of service
Local/Remote control selected

Status indication for the following plant items:-
(Insert plant items here)
shall use double indication to secure operation and prevent mistakes. Double indication shall function in such a way that an intermediate position will be given a "don't believe it" (DBI) signal.

2.2.3.3.3 Alarm Indication
The control system shall provide alarm indications which shall be segregated into the following categories: (insert or delete as required)
Trip alarms indicating the cause of trip
Urgent alarms needing immediate attention
Less urgent alarms
The Solution Provider shall provide a comprehensive listing of all of the relevant alarms grouped in the categories defined above.

2.2.3.3.4 Analogue Points
The following analogue indications shall be provided: (delete or modify as required)

MW, Mvar, A, V on all overhead line and cable circuits.
A on all bus coupler and section circuit breakers.
V and frequency on all separate bussing points (e.g. sections of busbars).
MW, Mvar, A, V on the low voltage side of all transformers.

2.2.3.3.5 Spare Points Required
The Solution Provider shall provide xx% spare points of all categories. (If different percentages required for different categories specify as appropriate)

2.2.3.3.6 Displays Required
One screen shall show the overall substation in overview. (If too large for one screen then it shall be spread over the minimum number of screens for clarity).
Each circuit shall be displayed on one screen for control purposes.
Each circuit display shall show the status of all elements of plant, tap change positions, MW, Mvar, A and V figures as appropriate.

Provision to display DBI condition shall be provided. It shall also indicate if there are any uncleared alarms. The system shall include alarm and sequence of event listings. (Any special requirements for these should be defined here)

2.2.3.3.7 Redundancy (The type and level of redundancy required should be defined in this section. Examples are given below)
The failure of any single element in the control system shall not lose any functionality whatsoever in the substation
OR
The failure of any single element in the control system shall not affect the control or interlocking of more than one circuit.
The failure of any single element shall not lose any indications of the status of any plant items in the substation.
In case of a failure in the telecommunication between NCC/DCC and the RTU or in the RTU/control system itself, a reserve alarm system independent from the RTU shall be provided.

2.2.3.3.8 Automatic Control Functions
(In this section the requirement for any automatic switching not covered by Section 2.2.3.2.2, synchronism check, synchronizing, network restoration automation or other automatic switching sequences should be defined)

2.2.3.3.9 Event Recording
(In this section the requirements for sequence of event recording shall be defined together with the resolution, for example:
All control commands, status changes and alarms shall be logged to a resolution of 1ms. Furthermore any requirement for any analogue traces should also be defined in this section).

2.2.3.3.10 Communication with Remote Control Centres
(In this section the requirement for any communication to any remote control centres shall be defined.)
Example: The substation shall be capable of being controlled locally or remotely from the District Control Centre located at DDDDDDDD using Protocol DD and from the National Control Centre located at NNNNNNN using Protocol NN.

The data and event records shall be capable of being accessed from the Maintenance Centre located at MMMMMMM using Protocol MM.

2.2.3.3.11 Requirement for Different Access by Different Staff

(In this section the requirements for different levels of access to the control system shall be defined.)

Example: Operational control of the substation shall be possible from a dedicated workstation located in the substation, from the District Control Centre and from the National Control Centre. The access shall be password protected and simultaneous access from more than one location at any time shall not be permitted.

Restricted access for protection staff from a dedicated terminal located at the substation and also remotely from the Maintenance Centre shall be permitted protected by a password. Access from only one location at any time shall be permitted. The operational control shall override any other control at all times.

Separate password protected restricted access shall also be allowed for other maintenance staff to interrogate the records to assist in maintenance planning.

2.2.3.4 Metering System
2.2.3.4.1 Circuits Requiring Energy Metering
The circuits requiring tariff metering are: (to be defined).

Parameters to be Metered, Direction and Accuracy:
(In this section the parameters MWh and/or Mvarh shall be defined and whether the measurement direction needs to be import and/or export and to what accuracy.)
Example: The feeders shall be metered for MWh and Mvarh for both import and export to an accuracy of 0.x% (including current and voltage detectors, meter accuracy etc.)

2.2.3.4.2 Check Metering Requirements

(If check metering is required this shall be defined here in the same way as for the main metering defining parameters, direction and accuracy class)

2.2.3.4.3 Remote Repeat Facilities Required

(If the metering information has to be repeated to any remote point then this should be defined in this section including the type of repeat method to be used).

2.2.3.4.4 Requirement for Different Tariffs

(With modern metering equipment a whole range of different tariff arrangements can be set up on the equipment. The full details of the particular tariffs required should be defined in this section including how these tariffs are to be repeated to the remote metering point.)

2.2.3.5 Communication System

2.2.3.5.1 Telephony

(In this section the requirements for any telephone system (or systems if more than one) shall be defined.)

2.2.3.5.2 Data Communications

(This section shall define the mode of communications to be used for sending data to the District, National or other remote control centres on the network. The type of data and the signalling rate shall be defined.)

2.2.3.5.3 Protection Signalling

(In a functional specification this should generally be left to the solution provider to define in order to meet the functional requirements of the protection system. However if the client has specific requirements these can be defined in this section.)

2.2.3.5.4 Modes of Communication to be Employed (PLC, FO, MW, PW etc)

(This section should define the available modes of communication available to the Solution Provider, such as fibre optic cable in the earth wire of overhead lines, microwave network, power line carrier and pilot wire. Full details of the type of fibre, microwave frequency and other key parameters as well as whether dedicated or multiplexed communication is used should be defined in this section.)

2.2.3.5.5 Redundancy Requirements

(This section should be used to define the redundancy requirements which the client wishes to have applied to the communications network. The redundancy to be applied may be different for data, telephones, protection signalling etc. and the specific redundancy required for each function should be defined.)

2.2.3.6 DC Supplies

In the event of a total loss of the AC auxiliary supply to the substation the battery(ies) shall be capable of providing the essential supplies to keep all of the control, protection and communication equipment functioning satisfactorily for a period of ‘x’ hrs. At the end of this period they shall still have sufficient stored energy to trip the maximum number of circuit breakers which may be called upon to clear a fault and also to be able to close ‘y’ circuit breakers.

2.2.4 Bonus/penalty clauses

An evaluation of the real unavailability shall be made regularly and compared with calculated (i.e. agreed) values given by the Solution Provider. Bonus or penalty is calculated accordingly as explained above. The Contractual obligations and rights for bonus or penalty are stated in the Commercial Section of the Specification.

(The rules for bonus and penalty have to be developed further. It is very important that economical terms and responsibilities are defined for a follow up of the real unavailability in operation compared to the calculated unavailability at the quotation stage.
There must also be rules for post commissioning changes made at the substation not foreseen at the time of the contract (e.g. further extensions of the switchgear within the “guarantee time”). This will of course affect the calculated values of availability from time of the contract. Asset Owner and Solution Provider must agree how these changes are going to affect the regular follow up on availability for bonus or penalty.)

2.2.5 Explanation of used terms

- **Asset Owner:** The owner of the substation and responsible for the operation of the substation. Operation of the substation could be done either by the Asset Owner own personnel or be outsourced.

- **Solution Provider:** The body responsible for the design and building of the substation.

- **Availability:** The probability that power is available at a certain point in the substation, e.g. at the MV bus.

- **Extendibility:** The possibility to extend a substation with new bays.

- **Life Cycle Cost:** The total cost for a substation during its whole lifetime. The different parts of life cost are specified in section 2.4.

- **Teleprotection:** Communication link between protections at either line ends for instantaneous tripping for faults along the whole line length, intertripping at breaker failure, etc.

- **Transfer paths:** A primary connection through the substation that can transmit power.

- **Forced outage:** An unexpected fault of an equipment that will cause surrounding circuit breakers to open and take primary equipment out of service immediately. Each specific fault can not be foreseen but faults can be calculated to happen with a certain time interval (MTBF = Mean Time Between Failure). The effect on power flow through the substation will depend on substation configuration and the exact location of the failure. The cause of the fault can depend on:
  - Equipment data insufficient either due to improper design or external overvoltages etc. higher than specified in requirements.
  - Improper operation of equipment.
  - Human error etc.

- **Permanent forced outage** - an outage whose cause is not immediately self-clearing, but must be corrected by eliminating the hazard or by repairing or replacing the component before it can be returned to service.

- **Transient forced outage** - an outage whose cause is immediately self-clearing so the affected component can be restored to service either automatically or as soon as a switch or circuit breaker can be reclosed or a fuse replaced.

- **Temporary forced outage** - an outage where the component is undamaged and is restored to service by manual switching operations without repair but possibly with on-site inspection.

- **Preventive maintenance:** The normal maintenance work, usually time based, that requires the corresponding primary equipment to be taken out of service. The outage due to preventive maintenance can be foreseen in advance.

2.3 Commercial Proforma

The Asset Owners may use their own normal commercial conditions of contract. This chapter defines only those particular requirements for use with a Functional Specification and does not include items, which are covered in the normal commercial conditions. The commercial conditions mentioned below follow a structure, which is only an example.

2.3.1 Invitation to tender - cover letter

In this section the Asset Owner can state the most relevant items concerning the tendering and contract, such as rough description of the scope of delivery, project time schedule limit, main pricing, evaluation and rejection principles, required deadline for reception and validity time of tenders as well as contact information.

The Asset Owner also gives a short description of the main evaluation principles of the tenders.

The criteria for the evaluation of tenders and the award of the contract are presented in Section 2.4, Evaluation.

2.3.2 Instructions to Tenderers

In this section the Asset Owner can state all the requirements for tender preparation, tender bond, qualification of tenders as well as basis for tendering, Tenderers responsibilities and obligations. Also, criteria and terms for the award of contract, handling of clarifications, interpretations and deviations to requirements, the guarantee terms as well as a list of required data to be submitted with the tender can be included here.

2.3.2.1 Information to be provided with the Tender

A contract based on functional specification should consist of a turnkey delivery and based on fixed price.
In addition to the data to be submitted with tenders in normal contracts, one based on functional specification shall also include:

- short system description describing the main ideas of substation design and the reason behind it
- availability, input data and results
- stage by stage proposals and emergency return to service
- single line diagram (different stages shown, if any)
- strategic spare parts (included in fixed price for same time period as bonus/penalty validity time)
- optional spare parts (unit prices)

2.3.2.2 Alternative Offers

Additional offers, not fully complying with the functional specifications, may be considered, if sufficiently well documented

2.3.2.3 Bonds

Special consideration shall be given to the handling of the relevant bonds, e.g. during the guarantee or the bonus/penalty validity period.

2.3.2.4 Tenderers Obligations

The Tenderer's responsibilities in the tender stage should include a careful examination of tender documents and a thorough site inspection in order to ensure that all boundaries and interfaces to existing network or substation are taken into consideration. Failure to do so is at the Tenderer's own risk.

Using functional specifications here should be stated the rules for handling any deviations to the requirements. Especially, the following should be taken into account:

- clear indication of any deviation in the tender regarding failure to fulfil the functional or boundary requirements

Also, the need for the successful Tenderer to assist with the planning permission/construction licence shall be paid attention to, as the functional specification may leave this open for a longer time than normally.

2.3.3 Special Terms and Conditions

2.3.3.1 Guarantee

There are two guarantees applicable to a functional contract.

2.3.3.1.1 Normal Plant Guarantee

Here the normal guarantee requirements should be defined.

2.3.3.1.2 Guarantee of Evaluated Life Cycle Cost (Long term Guarantee)

The guarantee terms shall consider also the application of penalty/bonus for availability performance besides those of the power losses.

The Long Term Guarantee terms shall consider the following:

- the start and the end of the bonus/penalty clause validity time (dead band or immediate start, length of validity period)
- bonus/penalty "pricing" and whether this is following a linear or an exponential pattern
- separation of unavailability due to the performance of substation equipment and systems and due to Asset Owners other systems. Consideration of handling of unavailability input data, which can vary significantly e.g. for overhead lines, and unavailability due to loss of auxiliary supply to the substation
- consideration of limitations due to maintenance work and outages not due to the substation
- separate handling of planned and forced outages (if applicable)

2.3.3.2 Failure to Fulfil the Boundary or Functional Requirements

The rules when specific functional requirement is not fulfilled should be defined here.

2.3.3.3 Failure to Rectify Faults or Non Compliances

In case of defects before taking over and during guarantee period, it shall also be considered that if the contractor fails to carry out corrections the client has the right to employ other parties without invalidating the bonus/penalty condition.

2.3.4 Payment Terms

This section should define the special payment considerations for a functional contract such as how often the bonus/penalty situation is checked out and the necessary payment done.

2.3.5 Modifications to the Substation during the Long Term Guarantee period.

This section shall define the rules for handling of modifications or extensions made to the substation during the Long Term Guarantee period.

2.4 Evaluation Proforma

This section defines the basis on which the different bids will be evaluated. This is a vital part of a functional specification as the factors on the different parameters in the evaluation formula effectively decide the most cost effective solution. This section presents the basis for defining the evaluation formula.

The bids will be adjudicated considering the following financial/economical evaluation formula:

EF = IC +AOC+ PMC + OC + PUC + UUC + EC + DC - B

The costs must be converted to an equivalent basis. This conversion should take the form of **capitalised cost calculation**, except for unplanned unavailability, extension costs and bonuses. The following information must be stated by asset owner:

- **Time period** for which cost should be calculated, this time is shorter or equal to expected life of the new equipment
- Specific **interest rate** to be used in calculation.

Direct costs (such as parts) can be calculated based on previous work or estimated from past experience. **Indirect costs** (such as downtime), while difficult to assign a cost value, should also be considered in the equation.

Other additional evaluation considerations are given in Clause 2.4.10.

2.4.1. Investment cost (IC)

Quoted price from the Solution Provider (turn-key)

Financing cost (ε)

2.4.2 Asset Owner Internal Costs (AOC)

a) Fixed Cost

Planning, pre-qualification, inquiry preparation and bid evaluation costs. As these fixed costs will be the same for each of the solutions, this figure may be neglected in the evaluation.

b) Variable Cost

In-house or contracted project costs on site (supervision, training, etc.)

Cost per man-hour of in-house labour or of contracted labour (ε/hr) × number of people × supervision/training time (hr)

2.4.3 Capitalised Costs for Planned Preventive Maintenance (PMC)

This cost is based on the level of required maintenance for the new equipment (maintenance plans): for each maintenance task, the calculation is based on the cost per man-hour of in-house labour or of contracted labour (ε/hr) × number of people × time to perform maintenance (hr) + spare parts (ε) + rental or purchase of special equipment (ε).

These capitalised costs are calculated for each maintenance task all along the life of equipment considering required maintenance frequencies, and then summed up.

2.4.4 Capitalised Operation Costs (OC)

Running losses in transformers, shunt reactors, etc. (ε).

2.4.5 Capitalised Costs for Planned Unavailability (PUC)

Loss of revenue from planned downtime:

- cost for power (ε/kW) × power (kW).
- cost for energy (ε/kWh) × power (kW) × time (hr).

These costs can be estimated from the maintenance plans, the necessary outages associated to each maintenance task, and based on the boundaries of the new substation (are there customers directly supplied by the substation without an alternative supply ?, etc.).

Outage planning administration costs (ε).

Network constraints: customer / generation constraint penalties (ε).

2.4.6 Costs for Unplanned Unavailability (UUC)

Loss of revenue from forced downtime:

The effects of each failure mode of each equipment on the substation are described in the FMEA (failure mode and effects analysis) process. It enables to calculate for each failure mode (based on load hypothesis):

- cost for power (ε/kW) × power (kW)
- cost for energy (ε/kWh) × power (kW) × restoration time (hr)
- estimated corrective maintenance costs

The estimated failure rate of equipment should also be given by the Solution Provider (no. of failures / yr).

This cost has to be combined with the probability of observing each failure mode during the considered time period (shorter or equal to expected life of the new equipment).

Then, the associated effects of each failure mode on the substation enable to determine the outage costs.

Network constraints: customer / generation constraint penalties (ε).

The unavailability cost and the number of years to be considered are given by the Asset Owner and these will be multiplied by the unavailable hours/year given by the Solution Provider.

Unavailability due to the substation equipment shall be considered here, not due to external circuits.

2.4.7 Extension Costs (EC)

The Solution Provider shall give an optional price for extensions of the substation valid e.g. for 10 years, also taking into account interest rate, etc.

2.4.8 Capitalised Costs for Decommissioning (DC)

This is the costs of dismantling and waste handling of substation material at the end of substation life.

Salvage value of dismantled equipment (income) should also be considered in the calculation of this cost.

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2.4.9 Bonuses (B)

This consists of possible land or other bonuses the Asset Owner wants to use (specified in the Boundaries Section of the specification)

2.4.10 Other Aspects (that are taken into consideration in evaluation of the tenders)

The Asset Owner may specify other factors that he wants to be considered in the evaluation of the Tenders, such as:

- consideration of Tenderer’s earlier experience in similar works, merits, organisation, plant facilities and financial resources
- consideration of client's earlier experience of Tenderer's similar deliveries regarding technical merits, quality, reliability, after-sales services, meeting delivery dates etc.
- consideration of other aspects of the tendered solution: quality, reliability, availability of spares, environmental impact, safety aspects
- other risks, political etc...

2.4.11 Recapitulative table

Data to be given by the utility to the solution provider	Unit	Data to be given by the solution provider to the utility	Unit
Average cost per man-hour of in-house labour	ε / hr	Cost of new equipment	ε
Cost per man-hour of contracted labour	ε / hr	Installation time	hr
Cost per man-hour of installation supervision	ε / hr	Testing time	hr
Cost per man-hour of testing labour	ε / hr	Training time	hr
Training costs	ε / hr	(Preventive) maintenance plans for each major piece of equipment : – frequency of each task – duration of each task – special conditions if any	 yr hr
Rental or purchase of special equipment for maintenance	ε / hr	Cost of spare parts	ε
Cost for running losses per circuit	ε / kWh	FMEA (failure mode and effects analysis) for each major piece of primary equipment : – probability of each failure mode (reliability data for each equipment) – effects of each failure mode on the bay / on the substation	 /yr /yr
Loss of revenue from planned downtime (cost for power per circuit)	ε / kW	Description of corrective maintenance tasks for each piece of equipment : – duration of each task – special conditions if any	In manuals h
Loss of revenue from planned downtime (cost for energy per circuit)	ε / kWh	Salvage value of equipment	ε
Outage planning administration costs	ε	Cost of dismantling and waste handling	ε
Customer / generation constraint penalties	ε	Extension cost for each circuit	formula
Loss of revenue from forced downtime (cost for power), to be considered for each circuit separately	ε / kW		
Loss of revenue from forced downtime (cost for energy), to be considered for each circuit separately	ε / kWh		
Cost of land	ε / sq.m		
Time period for capitalised calculation	yr		
Interest rate	%		

3. Evaluation of Substation Concepts

3.1 The Life Cycle of a Substation

A life cycle definition and model of electrotechnical systems in general is well described in an international standard [IEC 60300]. According to this document the life cycle of a substation was defined: “The life cycle of a substation is the time interval between a substations’s planning and it’s decommissioning.”

The life cycle of a substation is separated in life cycle phases. Two life cycle models for substations, a 3-phase and a 6-phase model, were derived from the general models of electrotechnical systems, **Table 1**

Electrotechnical System [IEC 60300]		**Substation**	
3-phase-model	**6-phase-model**	**3-phase-model**	**6-phase-model**
Acquisition	Concept and definition	Acquisition	Planning: Tendering, Offering, Evaluating, Contracting
	Design and development		Design: Basic and Detail Design
	Manufacturing		Procurement, Production and Site Preparation
	Installation		Installation, Testing and Commissioning
Ownership	Operation and maintenance	Ownership	Operation and maintenance
Disposal	Disposal	Disposal	Extension, Refurbishment, Decommissioning

Table 1: Life cycle phases of electrotechnical systems and substations

3.2 Method of Substation Evaluation

A wide variety of methods of evaluation have been developed. Depending on the evaluation subject and circumstances, they are more technically or economically oriented, precise or pragmatic, short or very time-consuming in their application. For the evaluation of substation concepts, we look for a combined economical-technical-environmental evaluation method, which can be adapted to the needs of its users. Powerful methods are described in international standards and regulations, such as the value management [VDI 2800], the life cycle costing [IEC 60300] or the model of the Life Cycle Assessment [ISO 14040].

Economical evaluations are the prerequisites to stay competitive. They range from the pure investment cost evaluation to the complete life cycle cost evaluation including capitalized cost. The additional evaluation of income, interest and taxes over the life cycle results in the economic value added. If additional qualitative values have to be considered the value management method or Life Cycle Assessment can be applied.

The developed and now described method of substation evaluation is a pragmatical combination between the economical on one side and technical, environmental and business partner evaluation on the other side. There are two dimensions of evaluation:

- Economical evaluation
- Qualitative evaluation

Both dimensions are evaluated and documented in a two-dimensional portfolio, **Figure 4**.

Description of the evaluation process:

1. Perform economical evaluation. This is usually straight forward and is done for all elements that could be directly expressed in money including initial investment cost as well as operation and maintenance cost of the life cycle of a substation.
2. Perform qualitative (technical, environmental and business partner) evaluation. Decide which values can be put into money (economical dimensions). If further qualitative values have to be considered, for example references of offered solutions, experience of former or existing business partnerships, required sustainability of business-relationship or corporate citizenship, a second dimension of evaluation is set up.
3. Perform overall evaluation. The economical and qualitative values are visualized in the evaluation portfolio.

A list of examples of economical and qualitative values is shown in **Table 2**.

Life cycle phases		Economical values	Qualitative values
Acquisition	Planning	Tender / Acquisition cost	Bidder references Bidder presence in country Bidder local organisation
		Offer / Evaluation cost	Compliance with the scope of supply Compliance with documentation Quality of supply
		Contracting / Legal cost	Bidder asset management capability
	Design	Development cost	
		Engineering cost	
	Procurement / Production / Site Preparation	Land acquisition cost	Community acceptance Environmental / Visual impact EMC, EMF generated
		Civil works	
		Equipment / system cost	
		Training cost	
		Transportation cost	Compliance with delivery time Delivery time
	Installation, testing and commissioning	Installation cost	Qualification of installation, testing and commissioning personal
		Testing cost	
		Commissioning cost	
Ownership	Operation	running losses	Operational Flexibility Safety Air pollution / climate tolerance Seismic tolerance Performance reserve
		building maintenance	
		switchyard maintenance	
	Preventive maintenance / Planned unavailability	Loss of revenue	Warranties Compliance with maintenance / repair time
		outage planning admin. cost	
		customer / generation constraint penalties	
		labour	Qualification of maintenance personal
		material	Capacity to supply spare parts
		travel expenses	
	Corrective maintenance / Unplanned unavailability	Loss of revenue	Compliance with outage time
		customer / generation constraint penalties	
		labour	
		material	
		travel expenses	
Disposal	Extension	extension cost cost of adapting to future requirements	Extendibility Independence of interfaces
	Refurbishment		Flexibility of scheme
	Decommissioning		
	Disposal		Environmental disposal impact

Table 2: Values of substation evaluation

3.2.1 Economical Evaluation

The economical evaluation is based on the Life Cycle Cost method [IEC 60300]. The Life Cycle Costing Process is based on the Life Cycle model. Models of substation life cycles are given in **Table 1** and examples of economical values are given in **Table 2**.

In recent years a wide variety of life cycle cost evaluation examples were published: LCC of electrotechnical systems [IEC 60300]; LCC of substations in general [cigre 01.1]; LCC of substation in general with examples 145 kV - AIS, GIS [DgLa03]; LCC of substations: 145 kV, 245 kV, 420 kV; H-scheme, double and single busbar; AIS, GIS [Aesch02]; Investment cost of substations: 145 kV, H-scheme, AIS, Hybrid [Leclerc02]; LCC of substations: 150 kV, AIS [Grpls02]; LCC of substations: 420 kV, AIS [Roussel02]; LCC and "Vendor Rating" of substations in general [Colombo02]; LCC of substations: 145 kV, H-scheme, AIS [Friberg02] and LCC of substation: 145 kV + 420 kV, AIS [Crvlo00].

The life cycle cost evaluation process is well described in IEC [IEC 60300] for general electrotechnical systems. For the evaluation of substation concepts the process is detailed below and simplified where possible:

1. Define life cycle phases of the substation and develop cost breakdown structure.
2. Define product / work breakdown structure.
3. Estimate the cost.
4. Summarise cost, either direct or capitalised.
5. Optional: Analyse optimisation potential by sensitivity analysis.

According IEC 60300-3-3 [IEC 60300], the following life cycle model and cost breakdown structure was defined:

$$LCC = Cost_{acquisition} + Cost_{ownership} + Cost_{disposal}$$

3.2.1.1 Cost of acquisition

The acquisition cost comprises all costs beginning with the planning process up to the installation, testing and commissioning of the substation up to handover to the Asset Owner. **Table 2** provides a list of typical acquisition costs. Planning and design cost, such as tendering, acquisition, offer, evaluation, legal and contracting costs can be used, but often they do not differ between the evaluated solutions. Main components are system cost (circuit breaker, disconnectors, earthing switches, current and voltage transformers, control & protection systems, transformers and associated protective devices and auxiliary equipment), cost of land acquisition, maintenance cost and cost of installation.

3.2.1.2 Cost of ownership

This cost portion contains all costs of the service period during the lifetime of the equipment. Due to the long time of this aspect, these costs should be capitalized. The cost of ownership consists of three major cost elements: operating cost, preventive maintenance cost and corrective maintenance cost:

Operating cost
Operating cost covers running losses, building and switchyard maintenance excluding the maintenance of the switchgear.

Preventive maintenance cost
The preventive maintenance cost comprises labour, material and travel expenses to maintain the switchgear equipment. Labour and travel expenses depend on location and could differ significantly from country to country. Depending on network conditions, there may be additional planned unavailability cost.

- Planned maintenance cost
  - Planned maintenance cost depends closely on the applied maintenance strategies.
- Planned unavailability cost
  - Planned unavailability occurs during scheduled maintenance and construction, e.g. for substation extension. Normally the redundancy of the substation layout should enable planned unavailability cost to be avoided.

Corrective maintenance cost
Corrective maintenance cost comprises of unplanned maintenance and unavailability cost.

- Unplanned maintenance cost
  - All unexpected failures which result in maintenance activities are covered by the unplanned maintenance cost.
- Unplanned unavailability cost
  - All cost related to interruption of energy flow not resulting from any scheduled activity is summarized as unplanned unavailability cost, normally following major failures.

3.2.1.3 Cost of disposal

These costs have to include all costs of extension, refurbishment, decommissioning and disposal after use and after subtracting earnings which can be received by selling the reusable materials like aluminium, copper etc. These costs are also capitalized.
Calculations of life cycle cost of a substation sometimes cover a period of time that is longer than the individual lifetime expectation of parts of the equipment. In particular, the relay and control equipment often has a shorter lifetime than the lifetime of the primary equipment, for example only half of it. Consequently the re-investment cost of such equipment has to be taken into account until the end of the calculation period is reached.
Life cycle cost for HV substations is calculated for a very long period of time, we assumed about 30 to 50 years dependent on the type of substation. So changes in the value of the money have to be respected. The calculation can apply the method of discounted cash flow in order to determine the net present value.
In addition to the discounting of the value of future expenses the effects of inflation can be taken into account.

3.2.2 Qualitative Evaluation

The qualitative evaluation covers the evaluation of technology, environment and of the business partners (Solution Provider or Asset Owner). It is based on the value management method and the Life Cycle Assessment [VDI 2800, ISO 14040] and life cycle model of a substation. A number of models of qualitative approaches for substation evaluations were published in recent years: An economical and technical assessment of substations 145 kV + 420 kV, AIS [Crvlo00]; A method of “Vendor Rating” [Colombo02]; A Value Based Comparison of Substations integrating LCC, Performance and Environmental Values [Wltm03].

The evaluation method of value management process is adapted for the qualitative evaluation of substation concepts. The steps are as follows:

1. Define qualitative evaluation criteria along the life cycle. Table II shows a selection of possible evaluation criteria.
2. Weigh the selected evaluation criteria, ranging from 0 to 1. The sum of weight should be 1.
3. Evaluate degree of realisation ranging from 0 to 1.
4. Multiply weight and degree of realisation for every evaluation criteria and add up to the qualitative value.

3.2.3 Overall Evaluation

The economical and the qualitative evaluations are put in a portfolio diagram, **Figure 4**. The economical value scale can be either in absolute life cycle cost (most economical solutions are on the left hand side of the portfolio) or in relative numbers between 0 and 1 (most economical solutions are on the right hand side of the portfolio). The qualitative value scale is a number between 0 and 1 (high quality solutions on the upper side). With the second presentation method the best overall solution is indicated by the longest vector distance from the origin.

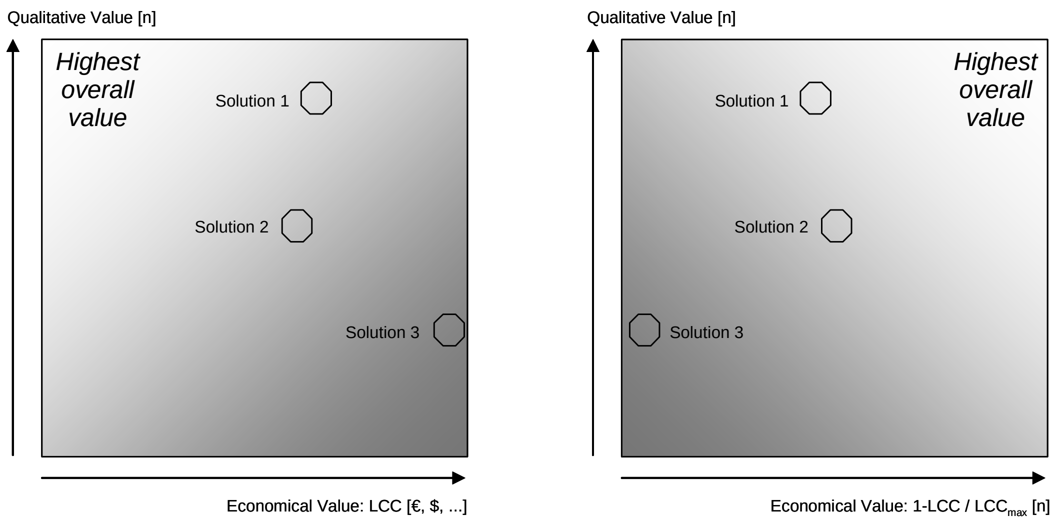

Figure 4: Evaluation portfolio for economical and qualitative values

4. Conclusions

4.1 Functional Specifications

The work of Task Force 1 has shown, by example, that it is possible to produce a Functional Specification as originally envisaged. However, during this exercise several problem areas were encountered which led the team to conclude that Functional Specifications in this format are unlikely to replace conventional specifications in the short term. However some parts of the functional specification concept can already be used today, for example evaluating the availability of different proposed solutions in the purchasing process or perhaps in encouraging functional thinking.

Some of the advantages and disadvantages of this type of Functional Specification follow:-

Advantages

- Encourages innovation
  This was the original objective when deciding to write a functional specification. Please remember that the successful innovative solutions of today will be the conventional solutions of tomorrow. Functional thinking on the part of the Asset Owner and Solution Provider will facilitate this process.

- Whole cost optimisation including engineering, installation and construction work as well as costs during the whole lifetime of the substation.
  This is a natural result of a functional specification.

- Assists in solving complex problematic sites
  Where sites are difficult for standard busbar configurations, the use of a functional specification can encourage innovative solutions to meet the functional requirements which would not have been realised by conventional specifications.

- Better response in terms of Life Cycle costs
  As it is necessary for evaluation purposes to look at Life Cycle Costs this is a natural benefit of this procedure.

Disadvantages

- Difficulty and time needed in preparing functional specification (future expectations, load flows, understanding of the sensitivity of certain parameters, e.g. outage rate and duration requirements may lead to excessive requirements, etc.)
  Preparing a functional specification will be new to virtually all Asset Owners. Deciding exactly what availability they really need and the allowable times for repair are critical activities. If unnecessarily onerous figures are applied this will result in an expensive solution with excessive redundancy.
  One way to overcome the difficulty of giving required availability figures could be, that the Asset Owner states that proposed solutions should be better or equal to a well known conventional solution. Solution Provider can then

compare an alternative solution with conventional solution and establish if the alternative is acceptable for the Asset Owner.

- Time required for preparing solutions.
  The time required by the Solution Providers to respond to a functional specification is much greater than is required for a conventional specification. This is due to the need to consider different solutions to find the optimum response. This will involve reliability and availability calculations as well as the evaluation calculations to arrive at the best offer.
  One way to overcome this problem is that the Solution Provider can establish a limited number of alternative solutions that are used to check it they fulfil the Asset Owner requirements. These solutions can be "re-used" and this will reduce the required time for preparation of the quotation.

- Costs to unsuccessful bidders
  The costs to unsuccessful bidders will be much higher than with a conventional specification for the reasons explained above. The cost can however be limited by some kind of "standardisation" of alternative solutions as explained above.

- It could be difficult to obtain relevant input data for availability calculations for some of the new innovative equipment (e.g. what failure statistics to use, how to motivate this and what rates can be promised?)
  Innovative solutions can be of different types from slight modification of existing apparatus to completely new designed switching machines. Input data for the slightly modified apparatuses are easy to justify but the new designed switching machines are more difficult. For the new designed switching machines there will not be any directly applicable data to use for reliability calculations. The data will have to be derived from data for similar equipment used in a different way. This opens the possibility of debate on the validity of the data used.

- Problems with evaluating and verifying different solutions with different approaches to availability calculations.
  This is a result of the point mentioned above.

- Bonus/penalty requirements very difficult to set and to manage
  The purpose of the bonus/penalty is to encourage better responses and to guarantee for the Asset Owner that the promised availability will be achieved. Trying to set meaningful targets which are not open to abuse is problematic.

- Unrealistic warranty periods required
  In order to achieve meaningful bonus/penalty clauses the duration of the Long Term warranty is likely to be too long to be practicable.

- Penalties inadequate to compensate Asset Owner for possible costs
  If a Solution Provider fails to deliver his promised solution with the defined performance the cost implications for the Asset Owner are likely to considerably exceed the recompense he can obtain via penalties on the contract.

- Problems if S/S extended by others during long term warranty period
  If the substation has to extended during the period of the Long term warranty and the work is given to a different Solution Provider this gives rise to commercial difficulties in defining responsibility for any future lack of performance. Asset Owners will not wish to be tied to one Solution Provider for future extensions.

- Asset Owner has less control over the plant connected to his system
  As the Asset Owner is defining the functional requirement of the substation rather than specific switching configuration and plant he will not have complete control over the plant connected to his system. This can give rise to problems with operators not being familiar with the plant giving rise to possible human error faults.
- Difficulties with standardising spares holdings
  It is more difficult for the Asset Owner to organise training and spare parts.

Whilst it is acknowledged that Functional Specifications in this format are unlikely to be commonly applied at present, it is believed that many aspects of the work will be of value to engineers working in this field.

4.2 Evaluation of Substation Concepts

High varieties of available solutions for HV substations require efficient methods of evaluation to support the decision for the right technology and the right arrangement. Life Cycle Costing determines the overall economical value. But not always, all important values for a sustainable business success can be expressed in economical numbers. In those cases, technical, environmental and business-partnership values, so called qualitative values, have to be properly considered as well. Proven methods of value management were adapted to the subject of high voltage substations. This approach is a framework to a well-balanced evaluation of solutions and the base of successful decision making for attractive and sustainable solutions:

The main conclusion is that there is no best solution for all different requirements. The basis for finding the best solution is the sound definition of requirements and the cooperation between Asset Owners and full scale Solution Providers to optimise developed solutions. This combined economical and qualitative evaluation supports the solution-optimisation and provides a powerful tool for successful decision making

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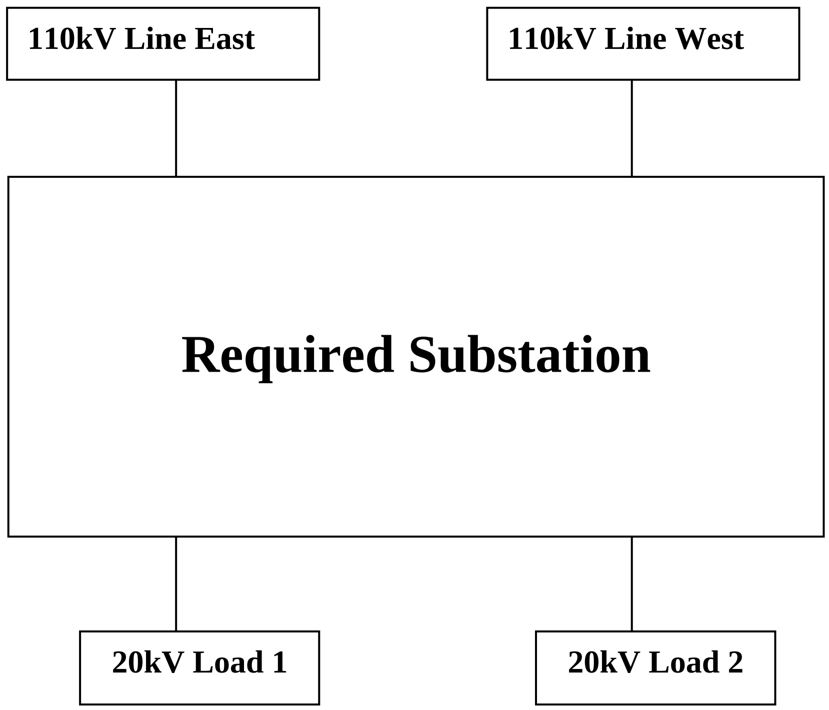
APPENDICES

A. FUNCTIONAL SPECIFICATIONS

The following Appendices show how the Proforma sections presented before are completed for a particular example. In this example the substation is assumed as a box with two nodes at 110kV and two nodes at 20kV.



Simple Diagram of Required Substation

The following Appendices show how the sections of the specification would have been completed and then two alternative solutions are evaluated using the Evaluation Formula. An additional Appendix is included to show the sensitivity of the costs to the different factors included in the Evaluation Formula.

Appendix A1 – Boundaries Example

Functional Specification – Boundaries Proforma Example

Explanations: *Italic text in blue is the one to be filled in by the Asset Owner for the inquiry and that which is ~~struck out~~ is an alternative which is not used*

Note: Please consider that this example has no intention to make any standard requirement. Asset owner has to check and verify the requirements from case to case.

2.1.1. Location and Spatial Constraints

The location of the site with its boundaries is at the *western side of town 'Example'*
Coordinates of the corner to north is xxxxxx N, yyyyyy E
The maximum available site area is *10,200* sq.m
Maximum length in east/west direction is *100* m
Maximum length in north/south direction is *120* m
The site is shown on Drawing No. *xxxxxx*,
and this drawing also shows the three bench marks (if available) located on the site and the locations of each of the external circuit entries (current and future, if known). Each of these entries is dimensioned from the dimensioned corner of the site which in turn can be accurately located from the benchmarks (if available).

A bonus of - $/sq.m reduction in the area used below that defined above shall (during construction) be allowed in the evaluation of the tenders.
If the solution Provider wishes to relocate the circuit entries (which must remain in the same general direction) then he shall advise in his tender the proposed revised locations and the reasons and advantages of so doing.
The level of the site above the sea level is generally *5.5-6 m* and the changes in level across the site are shown in the site drawing referred to above.

2.1.2 Primary Circuit Terminal Points and Physical Boundaries

2.1.2.1 Overhead Lines

Circuit Name: *Line 'West'*
Voltage: *123 kV*
Grid point location for centre of tower *xxxxxx* N *yyyyyy* E
For dimensions of tower refer to Drawing No. *xxxxxx*
If a double or multi circuit tower the circuit location on the tower should be clearly marked.
Orientation of tower centre line in direction of conductors is at *5 degrees* to the normal from the site boundary line.
Phasing for vertical formation is Top: - Middle: - Bottom: -
Phasing for horizontal formation is Left: *A* Middle: ***B*** Right: *C*
when viewed looking out to the line from the substation.

Stringing tension EDS (everyday stress) for span to substation gantry is: 20 N/mm^2 per phase
Conductors for span to substation are: *2-Duck or double ACSR 305/39, IEC 61089 designation: 305-A1/S1A-54/7, double conductor*
Rated current of circuit is *1600* A (conductor temperature 80°C deterministic as per latest IEC conditions)
Solution Provider shall supply suitable shackle points on landing structure.
Downdropper conductors are: *2-Duck or double ACSR 305/39*
Solution Provider should provide suitable clamps on the substation equipment to land these downdroppers.
Earthwire on tower is ~~*single/*~~*double*
Earthwire conductor is: *Suursavo Strong or AACSR 106/25, IEC 61089 designation: 91-A3/S1A-30/7*
Solution Provider shall provide suitable points on the substation landing structure to land the earthwire(s).

Circuit Name: *Line 'East'*
Voltage: *123 kV*
Grid point location for centre of tower *xxxxxx* N *yyyyyy* E
For dimensions of tower refer to Drawing No. *xxxxxx*
If a double or multi circuit tower the circuit location on the tower should be clearly marked.
Orientation of tower centre line in direction of conductors is at *0 degrees* to the normal from the site boundary line.
Phasing for vertical formation is Top: - Middle: - Bottom: -
Phasing for horizontal formation is Left: *C* Middle: *B* Right: *A*
when viewed looking out to the line from the substation.
Stringing tension for span to substation gantry is: *20 N/mm^2*
Conductors for span to substation are: *2-Duck or double ACSR 305/39*
Rated current of circuit is *1600* A (conductor temperature 80°C deterministic as per latest IEC conditions)
Solution Provider shall supply suitable shackle points on landing structure.
Downdropper conductors are: *2-Duck or double ACSR 305/39*
Solution Provider should provide suitable clamps on the substation equipment to land these downdroppers.
Earthwire on tower is ~~*single/*~~*double*
Earthwire conductor is: *Suursavo Strong or AACSR 106/25, IEC 61089 designation: 91-A3/S1A-30/7*

Solution Provider shall provide suitable points on the substation landing structure to land the earthwire(s).

2.1.2.2 Power Cables (Repeat data for each Power Cable Circuit)

Circuit Name: *Load 1*
Voltage: *24kV*
Type of cable *XLPE*~~*/LPOF etc.*~~
Number of cables per phase: *2*
Conductor size in sq. mm.: *800 sq.mm*

Method of bonding applied on cable sheaths is *single end~~/solid/cross bonded~~ at the substation end.*
Solution Provider *shall/ ~~shall not~~* provide suitable sealing ends to terminate the above-mentioned cables into the equipment within his supply.
Direction of approach of the cable circuit is shown on the site layout Drawing referred to above.
~~For oil filled cables the Solution Provider shall provide space and civil works for oil tanks as shown on Drawing No.~~
Pilot Cables laid with power cable 1 No. off and type *20 cores galvanic rated for 15 kV*.
No. of cores required in pilots for use of cable supplier: *4*
Pilot marshalling cabinet to be provided by *~~Cable supplier~~/Solution Provider*

Circuit Name: *Load 2*
Voltage: *24kV*
Type of cable *XLPE~~/LPOF etc.~~*
Number of cables per phase: *2*
Conductor size in sq. mm.: *800 sq.mm*
Method of bonding applied on cable sheaths is *single end~~/solid/cross bonded~~ at the substation end*
Solution Provider *shall/ ~~shall not~~* provide suitable sealing ends to terminate the above-mentioned cables into the equipment within his supply.
Direction of approach of the cable circuit is shown on the site layout Drawing referred to above.
~~For oil filled cables the Solution Provider shall provide space and civil works for oil tanks as shown on Drawing No.~~
Pilot Cables laid with power cable 2 No. off and type *20 cores galvanic rated for 15 kV*.
No. of cores required in pilots for use of cable supplier: *4 in each cable.*
Pilot marshalling cabinet to be provided by *~~Cable supplier~~/Solution Provider*

Load 1 and load 2 are feeding a common busbar on the customer's side.

2.1.2.3 Auxiliary Supplies

Auxiliary LVAC supply is provided by the Asset Owner ~~/ Solution Provider~~.
Auxiliary Supply Voltage: *400 V*
Rating per circuit kVA: *250 kVA*
No. of circuits: *One (1)*
Cable type and number off: *3x185* mm^2
Terminal point: *at LVAC board*
Termination kits *to be/ ~~not to be~~* supplied by Solution Provider.
Glands and lugs *to be/ ~~not to be~~* supplied by Solution Provider.
Tariff Metering for this supply to be provided by *Solution Provider/ ~~Others~~*

2.1.3 Basic Information for Civil Works

The minimum ground bearing pressure is *150* kN/m^2
The earth resistivity is *100* Ωm
The thermal resistivity is *not known*.

The existing water table is at a depth of *2.4 m*
The full information is included in the Soil Investigation report No. *xxxxxx* attached together with full details of location of the individual boreholes.
The site shall be *leveled/~~left sloping with gradient of~~*
The finished site level shall be *approx. 5.8 m (btw. 5.6 and 5.9 m)*
The Solution Provider *is/~~is not~~* required to remove all spoil from the site to a suitable dumping area
The area for site *facilities is within the site/~~in the area provided external to the site as shown on the site drawing~~*
The Solution Provider *is/~~is not~~* responsible for fencing and security of the site during construction
The interface with the access road to the site is *at the site boundary/ ~~at a point aa metres from the boundary~~* and the Solution Provider is required to include this access road in his price.
The interface to the existing drainage system shall be *at the site boundary/ ~~at a distance of dd metres from the boundary and the Solution Provider shall provide this external drainage system in his price.~~*
The interface for site water supplies shall be *at the boundary of the site/~~at a distance of ww metres from the boundary and the Solution Provider shall include the external water connection in his price.~~*
Solution Provider shall provide rooms for necessary electrical equipment supplied by him plus any future needs stated elsewhere. The common services building on the site shall include the following rooms as a minimum: *control room, office 16 sq.m, toilet, shower and store 12 sq.m.*
The required finishes are detailed in the attached finishes schedule xxxxx. The Solution Provider shall obtain approval from the relevant authorities.
The locations of any buried services (water, electricity, gas etc.) are *shown on the drawing xxxxxxx./ ~~shall be determined by the Solution Provider~~.*

2.1.4 Basic System Parameters

Nominal System Voltage	*110*	kV	
System Highest Voltage	*123*	kV	
Basic (LIWL) Impulse Level	*550*	kVp	
Switching Impulse Level	*N.A.*	kVp	
Power frequency Test Voltage	*230*	kV	
Short Circuit Level (3 phase)	*31.5*	kA	
Short Circuit Level (1 phase)	*6*	kA	
Short Time Current Duration	*1*	s	
System Earthing	*~~Solid/Resistance/~~ Reactance/~~Petersen coil/Ungrounded~~*		
Earth fault factor, max. time	*1.7, 10 s*		
Substation Neutral Earthing for Star Winding	*~~Solid/Resistance/ Reactance/Petersen coil/~~Ungrounded*		
Frequency	*50*	*Hz*	*+/-0.5%*

Nominal System Voltage	*20*	kV
System Highest Voltage	*24*	kV
Basic (LIWL) Impulse Level	*125*	kVp
Switching Impulse Level	*N.A.*	kVp

Power frequency Test Voltage *50* kV
Short Circuit Level (3 phase) *20* kA
Short Circuit Level (1 phase) *N.A.* kA
Short Time Current Duration *1* s
System Earthing *Not applicable*
Substation Neutral Earthing for Delta Winding ~~*Solid/Resistance/ Reactance/Petersen coil/*~~*Ungrounded*
Frequency *50* Hz *+/-0.5%*
Phase Shift between voltage systems
With the *123 kV* system considered as 0 degrees (12 o'clock) the *24 kV* system shall be at *30 degrees lagging (1 o'clock).*

2.1.5 Secondary System Aspects

2.1.5.1 Control Centres

The substation control system is required to interface with the following remote control centres:
District Control Centre: *Yes*
Location: *'Regional capital town'*
Existing control equipment manufacturer and type: *Harris XA21*
Mimic Diagram exists *Yes/~~No~~*
Modification of software and mimic diagram to be ~~*included/*~~*excluded* from contract
Protocol used: *DNP3.0*
Software version: *(8.2)*

National Control Centre: *Yes*
Location: *'National capital town'*
Existing control equipment manufacturer and type: *Harris XA21*
Mimic Diagram exists *Yes/~~No~~*
Modification of software and mimic diagram to be ~~*included/*~~*excluded* from contract
Protocol used: *IEC 60870-5-101*
Software version: *(8.2)*

2.1.5.2 Protection

The following protection devices exist at the remote ends of the overhead line circuits. Equipment provided at the substation must be compatible with and able to operate satisfactorily in conjunction with these existing devices. Alternatively the Solution Provider may completely replace these protection devices with equipment supplied and installed by him to be compatible with the new equipment being supplied at the new substation.

Circuit Name: *Line 'East'*
First Main protection: *Siemens 7SA510, v.3 (Distance relay with directional earth-fault function)*
Second Main Protection: *Alstom KCEG152 (Directional earth-fault relay, $R_F \leq 500\ \Omega$)*

Third Main Protection: *None*
Back-up Protection: *included in Alstom KCEG152 (Overcurrent relay)*
Autoreclose Equipment: *Siemens 7VK512*
Intertripping Equipment*:* -
Protection Signalling Equipment: *None*

Circuit Name: *Line 'West'*
First Main protection: Siemens *7SA511, v.3 (Distance relay)*
Second Main Protection: *ABB SPAS 1F1 J3 (Directional earth-fault relay, $R_F \leq 500\ \Omega$)*
Third Main Protection: *None*
Back-up Protection: *ABB SPAJ 3D1 J3 (Overcurrent relay)*
Autoreclose Equipment: *ABB SPAT 2D200 J3*
Intertripping Equipment: -
Protection Signalling Equipment: *None*

2.1.5.3 Communications

The following methods of communication are available on the circuits as detailed below:

Circuit Name: *Line East*

Power Line Carrier:	*~~Yes~~/No*
Phase to phase/Intercircuit coupling	
Line traps fitted at remote end	*~~Yes~~/No*
PLC equipment existing at remote end	*~~Yes~~/No*
Microwave	*~~Yes~~/No*
Fibre optic	*~~Yes~~/No*

(If yes give details of fibres, terminal point, jointing or junction box requirements, multiplexers included at remote end etc.)

Pilot Cables	*~~Yes~~/No*
Private/Rented	

(If yes give details of pilots, terminal point, jointing or junction box requirements, isolation transformers etc.)

Circuit Name: *Line West*

Power Line Carrier:	*~~Yes~~/No*
Phase to phase/Intercircuit coupling	
Line traps fitted at remote end	*~~Yes~~/No*
PLC equipment existing at remote end	*~~Yes~~/No*
Microwave	*~~Yes~~/No*
Fibre optic	*~~Yes~~/No*

(If yes give details of fibres, terminal point, jointing or junction box requirements, multiplexers included at remote end etc.)

Pilot Cables *~~Yes~~/No*
Private/Rented
(If yes give details of pilots, terminal point, jointing or junction box requirements, isolation transformers etc.)

Circuit Name: *Load 1*
Power Line Carrier: *~~Yes~~/No*
Phase to phase/Intercircuit coupling
Line traps fitted at remote end Yes/No (If yes provide details)
PLC equipment existing at remote end Yes/No (if existing, give details of type, bandwidth, frequency etc.)

Microwave *~~Yes~~/No*
(If yes give details of existing system)

Fibre optic *~~Yes~~/No*
(If yes give details of fibres, terminal point, jointing or junction box requirements, multiplexers included at remote end etc.

Pilot Cables *Yes/~~No~~*
Private/~~Rented~~
Pilot Cables laid with power cable 1 No. off and type 20 cores rated for 15 kV.
No. of cores required in pilots for use of cable supplier: 4 in each cable.
Pilot marshalling cabinet to be provided by ~~Cable supplier~~/Solution Provider

Circuit Name: *Load 2*
Power Line Carrier: *~~Yes~~/No*
Phase to phase/Intercircuit coupling
Line traps fitted at remote end Yes/No
(If yes provide details)
PLC equipment existing at remote end Yes/No
(if existing, give details of type, bandwidth, frequency etc.)

Microwave *~~Yes~~/No*
(If yes give details of existing system)

Fibre optic *~~Yes~~/No*
(If yes give details of fibres, terminal point, jointing or junction box requirements, multiplexers included at remote end etc.

Pilot Cables *Yes/~~No~~*
Private/~~Rented~~
Pilot Cables laid with power cable 2 No. off and type 20 cores rated for 15 kV.
No. of cores required in pilots for use of cable supplier: 4 in each cable.
Pilot marshalling cabinet to be provided by ~~Cable supplier~~/Solution Provider

2.1.6 Standards and Regulations

In the contract, the following standards concerning any material, equipment, civil work, installation, testing, etc. shall be followed:
Harmonised European Norms EN-60xxx,
IEC-standards,
National standards,
National guides etc.,
Additional guides,
as listed in the attached document No. xxxx

Additionally, the work shall fully comply with any EU Directives, National Laws and Regulations as well as relevant National Safety Code requirements.

2.1.7 Effects of environment on substation

The relevant maximum, minimum and average values of the environmental conditions at Site are as follows:
Wind: *min. withstand capability of 34 m/s for design*
Ice: *min. withstand capability of 20 mm (type testing requirement for switchgear)*
Max. snow level: *up to 1 m*
Soil frost: *average max. depth 0.4 m (usually in March), occasional winters may be down to max. 1.2 m*
Temperature: *average annual mean temp. 4 °C, min. temp. -28 °C and max. temp. +30 °C. Required min. design temp. -40 °C and max. +40 °C*
Humidity: *average mean 70 %, min. 35 %, max. 95 %. Required withstand for 100 %.*
Seismic level*: ≤0,1 g*
Pollution level: *medium light, class 2 for insulators (creepage distance 20 mm/kV)*
Keraunic level (thunderstorm days/yr): *25*
Rainfall: *annual average 600 mm*
Any other specific environmental requirements (e.g. flood levels, sandstorms, etc.): *None*

2.1.8 Effects of substation on environment

The allowed maximum values for the environmental impact of the Site are as follows:
Noise level: *55 dBA sound pressure measured at the fence*
Electric field: *5 kV/m measured at the fence*
Magnetic field: *100 μT measured at the fence*
Corona level: *<30 dB at rain, <15 dB at dry weather acc. to IEC-CISPR 18 (measured with 0,5 MHz frequency at a distance of 20 m from switchgear edge)*
Aesthetic restrictions (e.g. height): *Max. height of 25 m for any structure, design shall lead to aesthetically approved result, because Site location is beside a major motorway*

Style of building, archeological restraints: *approval, i.e. planning/construction permit required from municipal authorities*
Oil damage prevention: *Site is beside a river. Thus, the stricter rules of the detailed specification shall be followed. See document No. xxxx*
Laws: *Waste Law, Chemicals Law*
Regulations: *Waste act, Chemicals Act, client's environmental policy and guide*

2.1.9 Safety requirements

The minimum safety aspects to be taken into account in design, during construction, installation and testing at Site as well as for use, inspection, testing and maintenance of the substation in use are as follows:
Safety standards to be fulfilled: *EN 50110 (international), SFS 6000, SFS 6001 (national)*
National Safety code *None*
Safety regulations of the client *according to the specifications of the enquiry*
Step and touch potential rise: *max. $1500/\sqrt{t}$ V step voltage, $1500/\sqrt{t}$ V touch voltage potential rise and 650 V ground potential rise for 0.5 s regarding telephone networks*
Minimum clearances*: phase-to-phase 1300 mm, phase-to-earth 1150 mm, height from insulator lowest point to ground 2600 mm (if access is allowed while the equipment is alive)* If the equipment can be maintained by withdrawing to another area, clearances can be reduced provided they comply with relevant IEC standards for phase to earth and phase to phase and are proved by impulse testing)
Restrictions on live working: *live working is not allowed. Safety guard required when minimum distance between live part at 110 kV and grounded part of machines is 5 m.*
Any other specific safety requirements (Substation security requirements, Substation lighting, etc.): *burglar and fire alarm systems for the control building and switchyard lighting are required.*

2.1.10 Constraints

Specific constraints:
Nominal current rating for 123 kV circuit breakers: minimum 1600 A
Specific requirements for 110/20 kV transformer interchangeability is stated in document No. xxxx and drawing yyyy.
DC system of the substation: 110V.

2.1.11 Work at Other Locations

There is no work needed at remote end substations by the Solution Provider, if the protection system provided at the substation is fully compatible with the existing protection at the remote ends.

Appendix A2 – Functional Requirements Example

2.2 Example Functional requirements

Explanations: *Italic text in blue is the one to be filled in by the Asset Owner for the inquiry and that which is ~~struck out~~ is an alternative which is not used*

2.2.1.1. Power flow external and internal in substation

2.2.1.1.1 External power flow for all objects connected together (load case 1)

Electrical loads shall be specified at each primary connection point to the substation:

- normal load with direction *Line East: 104 MW (in), 38 Mvar (in)*
  Line West: 50 MW (out), 12 Mvar (out),
  Load 1: 27 MW (out), 13 Mvar (out)
  Load 2: 27 MW (out), 13Mvar (out)
- maximum continuous load active and reactive together with direction (for each circuit independently and not simultaneously)
  Line East: 135 MW (in), 65 Mvar (in)
  Line West: 104 MW (in), 38 Mvar (in)
  Load 1: 45 MW (out), 22 Mvar (out)
  Load 2: 45 MW (out), 22 Mvar (out)
- maximum load for *8 hours* active and reactive together with direction (for each circuit independently and not simultaneously)
  Line East: 135 MW (in), 65 Mvar (in)
  Line West: 104 MW (in), 38 Mvar (in)
  Load 1: 54 MW (out), 26 Mvar (out)
  Load 2: 54 MW (out), 26 Mvar (out)
- maximum load for *2 hours* active and reactive together with direction (for each circuit independently and not simultaneously)
  Line East: 140 MW (in), 70 Mvar (out)
  Line West: 110 MW (out), 40 Mvar (out)

Load 1: 60 MW (out), 29 Mvar (out)
Load 2: 60 MW (out), 29 Mvar (out)

- maximum and minimum operating (continuous) voltage level: *110% and 95%.*

2.2.1.1.2 External power flow for split operation (load case 2)
Not necessary to study split operation separately.

2.2.1.2 Future extensions required and changes in power flow
No allowance is required for future extensions.

2.2.1.3.1 Availability
2.2.1.3.1.1 Reliability of external primary circuits (to be used as input for calculations)
These data refers to outages due to faults and outages due to preventive maintenance of the external primary circuits connected to the load points (terminals) of the substation.

Load points (terminals) and load cases are shown in *fig. xxx attached.*

Overhead Lines
Circuit name: *Line East (50 km long, total fault rate 1 fault/100 km*year, divided into permanent, transient and temporary as stated below)*

Permanent forced
outage rate: *0.05 number/yr*
outage duration: *18 h/outage*

Transient forced
outage rate: *0.40 number /yr*
outage duration: *0.5 sec/outage*

Temporary forced
outage rate: *0.05 number/yr*
outage duration: *2 h/outage*

Preventive maintenance
interval: *8 yr*
scheduled outage duration: *72 h each*

Circuit name: *Line West (50 km long, total fault rate 1 fault/100 km*year)*

Permanent forced
outage rate: *0.05 number/yr*
outage duration: *18 h/outage*

Transient forced
outage rate: *0.40 number /yr*
outage duration: *0.5 sec/outage*

Temporary forced
outage rate: *0.05 number/yr*
outage duration: *2 h/outage*

Preventive maintenance
interval: *8 yr*
scheduled outage duration: *72 h each*

2.2.1.3.1.2 Reliability of external Auxiliary Supplies
The external auxiliary supply will come from the local utility.

Permanent forced
outage rate: *0.05 number/yr*
outage duration: *8 h/outage*

Preventive maintenance
interval: *16 yr*
scheduled outage duration: *4 h each*

2.2.1.3.2 Required target values to be fulfilled
Generic Requirements
The planned outages on any external connection point shall not require the shutdown of any other external connection point.
The switching configuration shall be designed such that any fault on one external connection point shall not cause the loss of any other external connection point. (A short term loss of another external connection point for a maximum of 60 seconds shall/~~shall not~~ be acceptable to allow automatic switching to be performed. This short term outage period will be taken into account in the calculation of unavailability for bonus/ penalty)
The bussing points within the substation shall be designed such that the planned and unplanned outages are included within the unavailability figures for each of the external connection points.
Both infeed points cannot be taken out simultaneously and the same applies for both load points.
The effect of auxiliary supplies on the unavailability of all external connection points must be taken into account. The maximum allowed outage of the auxiliary supply is 10 h.

2.2.1.3.2.1 Forced outages
The target values for unavailability and other reliability indices for external load points include all contributions originating inside or outside the substation.

Load Case No.1:
Transfer paths: From Line East to Line West
Transfer paths: From Line East or Line West to Load 1
Transfer paths: From Line East or Line West to Load 2

Single events
Load Point: ***Line West***
Target values
max. forced interruption frequency: *0.6 number /yr*
max. restoration time t_r for faults inside substation: *36 h*

Load Point: ***Load 1***
Target values
max. forced interruption frequency: *0.05 number /yr*
max. restoration time t_r for faults inside substation: *48 h*

Load Point: ***Load 2***
Target values
max. forced interruption frequency: *0.05 number /yr*
max. restoration time t_r for faults inside substation: *48 h*

Overlapping events (simultaneous outage of two or several load points)
Load Points: ***Load 1 and 2***
Target values
max. forced interruption frequency: *0.005 number /yr*
max. restoration time t_r for faults inside substation: *3 h*

Unavailability in hours/year can be calculated by multiplying the interruption frequency by the restoration time.

2.2.1.3.2.2 Corrective maintenance outages
Regulations (national etc):
It is allowed to operate a disconnector remotely to change a particular switching arrangement without personal verification. Earthing switches must be verified locally before work can commence.

Logistic delay: *2 hours*
Gives the delay for operational staff to go to the substation for switching actions etc.
Additional time for switching/bypassing a fault in the substation: *0.5 hours.* This means that total time for bypassing of faulty equipment by switching and restoration of service is *2.5 hours*.

Logistic delay: *4 hours*
Transport time of the spare part to the substation.

2.2.1.3.2.3 Primary equipment preventive maintenance outages
Maintenance of primary equipment should only be done during normal load situations, see clause 2.1.1.1. In addition to that it is assumed that each of the two lines can feed both Loads.

Maintenance conditions and restrictions
Name of feeders and transfer paths, which must be kept in service:
Line East to Load 1 or
Line East to Load 2 or
Line West to Load 1 or
Line West to Load 2.

Maintenance work is only allowed to be done during the following time of the year:
From 2nd May to 30th October as agreed with the Asset Owner.

It is assumed that maintenance will be carried out by *one crew with 2 people working normally 8 hours per day*. The Solution Provider should calculate and give the actual required outage duration with these assumptions.

Target values
The target values associated with preventive maintenance of primary equipment in the substation are:

All components requiring outage of only Line East:
min. interval: *8 yr* (max. maintenance frequency = interval^{-1})
max. scheduled outage duration: *36 hours* per maintenance occasion

All components requiring outage of only Line West:
min. interval: *8 yr*
max. scheduled outage duration: *36 hours* per maintenance occasion

All components requiring outage of only Load 1:
min. interval: *8 yr*
max. scheduled outage duration: *8 hours* per maintenance occasion

All components requiring outage of only Load 2:
min. interval: *8 yr*
max. scheduled outage duration: *8 hours* per maintenance occasion

Overlapping events (simultaneous outage of two or several load points)
Line East and Load 1
min. interval: *8 yr*
max. scheduled outage duration: *8 hours* per maintenance occasion
Note: Maintenance on these components should be done during the outage period of the line.

Line West and Load 2
min. interval: *8 yr*
max. scheduled outage duration: *8 hours* per maintenance occasion
Note: Maintenance on these components should be done during the outage period of the line.

2.2.2 Transformation

2.2.2.1 Voltage Control

2.2.2.1.1 General

The transformation of power shall be equipped with on-load voltage regulating control for varying the effective voltage ratio during normal load situations but without changing the phase displacement.

If the voltage regulation causes impurities in the insulation media, the voltage regulation must be housed in a separate container. This is to prevent impurities spreading into the other insulation media of the power transformation.

Voltage regulation shall be physically located on *110 kV* side of the transformation.

2.2.2.1.2 Automatic Voltage Control

Voltage on *20 kV* voltage level shall be kept constant within ± *2%* of required voltage level from zero to full MVA-load through the transformation. This shall be possible for any feeding voltage between minimum and maximum.

The required voltage level to keep constant shall be the level *at a point 5 km distance (indicates load drop compensation necessary) in the 20 kV system*. The voltage control equipment thus shall have the necessary voltage drop compensation facility to make this possible.

Maximum voltage on *20 kV* side of transformation must be limited to maximum voltage level of system, i.e. voltage control must not raise voltage higher than this value even if voltage at remote point will be lower than required.

Voltage control shall *normally be in automatic mode but it shall be possible from remote and local to change control to manual operating mode and thus make regulation by hand. It shall also be possible to change the voltage set point value from remote and local.*

The voltage control equipment shall include, but not be limited to, the following as required:

- Range of setpoint adjustment ±*0-6%* of rated voltage, in steps of *1%*.
- Undervoltage setting *not used.*

If there is more than one power transformation device supplied, necessary means should be provided to operate the voltage control in independent or parallel mode.

2.2.3 Secondary equipment
2.2.3.1 Protection
2.2.3.1.1Fault clearance time
110 kV system:
All faults within the Substation shall be cleared by main protection within *140 milliseconds*.
All faults on external circuits shall be cleared within *140 milliseconds* for the first *80%* of the circuit and within *500 milliseconds* for the final (100 – 80) %.
20 kV system:
All faults within the Substation shall be cleared by main protection within *150 milliseconds*.
All faults on external circuits shall be cleared within *200 milliseconds* covering the whole circuit.

2.2.3.1.2 Redundancy
Redundancy is not required.

2.2.3.1.3 Failure of Primary Fault clearing device
Breaker fail protection not required.

2.2.3.1.4 Stability and Sensitivity of Detection Required
All of the protection shall remain stable for faults outside of their protected zone for currents up to the maximum which can occur, based upon the system parameters defined in the Boundaries Section. Current detectors shall be dimensioned in such a way making this possible. All protections shall remain stable for external faults in the presence of capacitive charging currents.

All protection devices shall ensure that internal faults will be cleared under the minimum fault level conditions defined in the Boundaries Section.

For transformer and reactor electrical protection devices it is acknowledged that a small unprotected zone close to the neutral may occur. This unprotected zone shall not exceed *10%* of the winding.

2.2.3.1.5 Back Up Requirements
In the event of failure of the main protection, a system of back up protection shall be provided.
110 kV system:
The Back Up protection shall ensure that all faults within the substation and within the maximum/minimum fault level range as defined in the Boundaries Section shall be cleared in less than *1000 milliseconds*.
For primary faults in the adjacent substation and further external circuits remote back up protection shall be provided at the substation belonging

to the delivery. These ensure that in the event of failure of the main protection at the adjacent substations, faults at each of the adjacent station busbars shall be cleared from the system within *500 milliseconds*.
20 kV system:
The Back Up protection shall ensure that all faults within the substation and within the maximum/minimum fault level range as defined in the Boundaries Section shall be cleared in less than *800 milliseconds*.

2.2.3.1.6 Ability to store fault records
One main protection on each *110 kV circuit* ~~or bussing point~~ shall be able to store analogue fault records. These fault records shall be capable of being downloaded at least locally at the relays by means of a laptop computer ~~or/~~*and* remotely via the communications system.

2.2.3.1.7 Adjustable Settings
The main protection relays *do not have to include* ~~*shall be capable of storing up to s number of*~~ separate groups of settings. ~~*This requirement shall apply to overhead line, cable, transformer, reactor, bussing point protections.*~~

~~*Switching from one group of settings to another shall be possible:*~~
~~- *Automatically,*~~
~~- *Locally at the relay,*~~
~~- *Remotely via the communications system.*~~

2.2.3.2 Special Features
2.2.3.2.1 Power Swing Stability
The protection systems ~~*shall*~~*/shall not* operate for the occurrence of power swings on the network.

2.2.3.2.2 Autoreclose
On the occurrence of a fault, which may reasonably be assumed to be of a transient or temporary nature, the system shall automatically reclose the faulty circuit. *Therefore, this shall be applied for the 110 kV lines and the dead time of 400 milliseconds.*
~~*If the initiating fault is a single phase fault and single-phase tripping is used then reclosure shall be on a high speed single phase basis.*~~
~~*If the fault is of a multiphase nature then the*~~ *The tripping and reclosure shall always be on a three phase basis.*
~~*If the circuit after reclosing remains in service for a period of 10 seconds then the autoreclose mechanism shall reset. If, however, the circuit trips within the period of r seconds from reclosure the auto reclose mechanism for that circuit shall lockout.*~~
~~***Or***~~
In case of an immediate re-tripping after the high speed autoreclose a second delayed autoreclose shall be initiated and the breaker closed after *60 seconds.*
If the circuit after this second reclosing remains in service for a period of *15 seconds* then the autoreclose mechanism shall reset. If, however, the circuit trips within the period of *15 seconds* from reclosure the auto

reclose mechanism for that circuit shall lockout.
Auto reclose shall not be initiated for faults on circuits for which it is not reasonable to assume that the fault may be transitory, except as part of an auto isolation scheme.
If a protection for a part of the system, which may not be reasonably likely to have transient faults, operates at the same time as the protection which will initiate autoreclose then the autoreclose shall be blocked.
If a circuit is a composite combination of more than one isolatable section, then on the occurrence of a fault on one section, an auto isolation sequence shall be started, which will trip the total circuit and automatically isolate the faulty part of the circuit and restore the remaining healthy part to service.
Automatic reclosure shall be blocked for 15 seconds, when the corresponding circuit breaker is closed manually (both in local and remote control cases).
Only those protection functions that operate faster than 150 ms may start the high speed autoreclosure. Any delayed protection function shall start only the delayed autoreclosure.

2.2.3.2.3 Layout of Equipment to minimise risk of Human Error
The equipment shall be arranged in the enclosures and labelled in such a way as to reduce the risk of a person confusing the equipment associated with one circuit with that of another. In general equipment for different circuits shall be located within different enclosures, but where the quantity of equipment is such that this would be wasteful on space and steelwork, clear segregation within the common enclosure shall be employed.

2.2.3.2.4 Testing facilities
The equipment shall be easily tested for each protective function with standard testing devices and without causing erroneous tripping of breakers. All protection relays shall be provided with test switches making secondary testing possible with the primary object in full service and protected by the redundant or back up protection.

Test switches shall be designed in such a way that there is no risk of:
- inadvertent opening of CT-circuits
- spurious trip signals issued

when protection relays are shifted from service to test position or vice versa.
In order to fulfil the above requirement all test switch connections shall be made during design stage. No wiring whatsoever should be necessary during the routine testing of the protection relays.
Testing personnel shall only need to plug in a test handle in the test switch to get the correct sequence of opening trip circuits, short-circuiting CT-circuits, opening VT-circuits etc.

2.2.3.3 Control System

2.2.3.3.1 Control Functions

The control system to be provided shall provide control functions for the following items:

Circuit Breakers
Disconnectors
Earth Switches
Tap Changer
~~*Shunt reactor*~~
~~*Shunt Capacitor Bank*~~
Protection In/Out Switching
Autoreclose In/Out Switching

Control for the following plant items:

Circuit Breakers
Disconnectors
Earth Switches
shall be done in a two step operation:

- 1st step shall "reserve" the chosen object and block operation of all other objects.
- 2nd step shall execute the chosen command.

Interlocking shall be provided by *software or hardwired* ~~*or both or neither*~~

2.2.3.3.2 Status Indication

The control system shall provide status indication monitoring for the following functions:

Circuit Breakers
Disconnectors
Earth Switches
Tap Change Auto/Manual/Parallel/Independent
~~*Shunt Reactor Control status*~~
~~*Capacitor Bank Control status*~~
Protection/Autoreclose In or Out of service
Local/Remote control selected

Status indication for the following plant items:

Circuit Breakers
Disconnectors
Earth Switches
shall use double indication to secure operation and prevent mistakes. Double indication shall function in such a way that an intermediate position will be given a "don't believe it" (DBI) signal.

2.2.3.3.3 Alarm Indication

The control system shall provide alarm indications which shall be segregated into the following categories:

Trip alarms indicating the cause of trip
Urgent alarms needing immediate attention as follows:

- *Transformer failure*
- *Circuit breaker or disconnector/earthing switch failure*
- *Protection/control device failure*
- *Telecommunication (or device) failure*

Less urgent alarms

The Solution Provider shall provide a comprehensive listing of all of the relevant alarms grouped in the categories defined above.

2.2.3.3.4 Analogue Points

The following analogue indications shall be provided:

MW, Mvar, ~~A,~~ V on all overhead line and cable circuits.

MW, Mvar ~~A~~ on all bus coupler and section circuit breakers.

V and frequency on all separate bussing points (e.g. sections of busbars).

MW, Mvar, ~~A,~~ V on the low voltage side of all transformers.

2.2.3.3.5 Spare Points required

The Solution Provider shall provide *10%* spare points of all categories. (If different percentages required for different categories specify as appropriate)

2.2.3.3.6 Displays Required

One screen shall show the overall substation in overview.

Each ~~*circuit*~~ *voltage level* shall be displayed on one screen for control purposes.

Each circuit display shall show the status of all elements of plant, tap change positions, MW, Mvar~~, *A*~~ and V figures as appropriate.

Provision to display DBI condition shall be provided. It shall also indicate if there are any uncleared alarms. The system shall include alarm and sequence of event listings. *The alarm status shall be clearly shown on the lists e.g. by appropriate colouring*.

2.2.3.3.7 Redundancy

~~The failure of any single element in the control system shall not lose any functionality whatsoever in the substation~~

~~OR~~

The failure of any single element in the control system shall not affect the control or interlocking of more than one circuit.

The failure of any single element shall not lose any indications of the status of any plant items in the substation.

In case of a failure in the telecommunication between NCC/DCC and the RTU or in the RTU itself, a reserve alarm system consisting of 10 group alarms independent from the RTU/control system shall be provided.

2.2.3.3.8 Automatic Control Functions

Synchronism check functions shall be provided for both 110 kV lines.

2.2.3.3.9 Event Recording
All control commands, status changes and alarms shall be logged to a resolution of *1 ms. Main protection shall be provided with fault location indication to the RTU and other fault data (e.g. ph-ph or ph-g) and event recording that can be transferred to the maintenance staff at a remote location (Maintenance Centre).*

2.2.3.3.10 Communication with Remote Control Centres
The substation shall be capable of being controlled locally or remotely from the District Control Centre located at *'Regional capital town'* using Protocol *DNP3.0* and from the National Control Centre located at *'National capital town'* using Protocol *IEC 60870-5-101*.

The data and event records shall be capable of being accessed from the Maintenance Centre located at *'Regional capital town' e.g. via modem and/or using a protocol ~~MM~~ and software proposed by the Solution Provider.*

2.2.3.3.11 Requirement for Different Access by Different Staff

Operational control of the substation shall be possible from a dedicated workstation located in the substation, from the District Control Centre and from the National Control Centre. The access shall be password protected and simultaneous access from more than one location at any time shall not be permitted.

Restricted access for protection staff from a dedicated terminal located at the substation and also remotely from the Maintenance Centre shall be permitted protected by a password. Access from only one location at any time shall be permitted. The operational control shall override any other control at all times.

Separate password protected restricted access shall also be allowed for other maintenance staff to interrogate the records to assist in maintenance planning.

2.2.3.4 Metering System
2.2.3.4.1 Circuits Requiring Energy Metering
The circuits requiring tariff metering are:
- *Load 1 and*
- *Load 2.*

~~*Parameters to be Metered, Direction and Accuracy:*~~
The feeders shall be metered for *MWh and Mvarh* for ~~*both import and*~~ *export* to an accuracy of *1%* (including current and voltage detectors, meter accuracy etc.). *The energy meters of accuracy class 0.5 will be provided by another Service Supplier.*

2.2.3.4.2 Check Metering Requirements

Check metering is not required.

2.2.3.4.3 Remote Repeat Facilities required
The metering information will be repeated to the Balance Centre. The equipment for this will be provided by another Service Supplier.

2.2.3.4.3 Requirement for Different Tariffs
Single price tariff will be used.

2.2.3.5 Communication System
2.2.3.5.1 Telephony
The telephone system shall include own channels for:

- *telephone/fax (same number)*
- *energy metering*
- *reserve alarm system (robot phone type)*
- *possible modem access*

2.2.3.5.2 Data Communications
The RTU will be connected to a telecommunication system provided by another Service Supplier.

2.2.3.5.3 Protection Signalling
The main protection (distance protection POTT) of both 110 kV lines shall be provided with the possibility to use communication schemes, either directly from the first energisation of the substation or to be implemented in the future.

2.2.3.5.4 Modes of Communication to be Employed (PLC, FO, MW, PW etc)
The telecommunication to the DCC and NCC will employ a multiplexed communication via a microwave network or optical fibres provided by another Service Supplier. The main protection of the 20 kV cables shall use dedicated pilot wires with 15 kV isolation level.

2.2.3.5.5 Redundancy Requirements
The RTU shall be able to use duplicated digital communication channels (NCC and DCC) with independent characteristics. If both channels are out of order, the reserve alarm system shall be activated.

2.2.3.6 DC Supplies
In the event of a total loss of the AC auxiliary supply to the substation the battery(ies) shall be capable of providing the essential supplies to keep all of the control, protection and communication equipment functioning satisfactorily for a period of *10 hrs*. At the end of this period they shall still have sufficient stored energy to trip the maximum number of circuit breakers which may be called upon to clear a fault and also to be able to close *two* circuit breakers.

2.2.4 Bonus/penalty clauses

An evaluation of the real unavailability shall be made regularly and compared with calculated (i.e. agreed) values given by the Solution Provider. Bonus or penalty is calculated accordingly as explained above. The Contractual obligations and rights for bonus or penalty are stated in the Commercial Section of the Specification.

2.2.5 Explanation of used terms

- **Asset Owner:** The owner of the substation and responsible for the operation of the substation. Operation of the substation could be done either by the Asset Owner own personnel or be outsourced.

- **Solution Provider:** The body responsible for the design and building of the substation.

- **Availability:** The probability that power is available at a certain point in the substation, e.g. at the MV bus.

- **Extendibility:** The possibility to extend a substation with new bays.

- **Life Cycle Cost:** The total cost for a substation during its whole lifetime. The different parts of life cost are specified in section 2.4.

- **Teleprotection:** Communication link between protections at either line ends for instantaneous tripping for faults along the whole line length, intertripping at breaker failure, etc.

- **Transfer paths:** A primary connection through the substation that can transmit power.

- **Forced outage:** An unexpected fault of an equipment that will cause surrounding circuit breakers to open and take primary equipment out of service immediately. Each specific fault can not be foreseen but faults can be calculated to happen with a certain time interval (MTBF = Mean Time Between Failure). The effect on power flow through the substation will depend on substation configuration and the exact location of the failure. The cause of the fault can depend on:
  - Equipment data insufficient either due to improper design or external overvoltages etc. higher than specified in requirements.
  - Improper operation of equipment.
  - Human error etc.

- **Permanent forced outage** - an outage whose cause is not immediately self-clearing, but must be corrected by eliminating the hazard or by repairing or replacing the component before it can be returned to service.

- **Transient forced outage** - an outage whose cause is immediately self-clearing so the affected component can be restored to service either automatically or as soon as a switch or circuit breaker can be reclosed or a fuse replaced.

- **Temporary forced outage** - an outage where the component is undamaged and is restored to service by manual switching operations without repair but possibly with on-site inspection.

- **Preventive maintenance:** The normal maintenance work, usually time based, that requires the corresponding primary equipment to be taken out of service. The outage due to preventive maintenance can be foreseen in advance.

Appendix A3– Commercial Example

Functional Specification - Commercial Conditions Example

This Section is provided as a supplement to the Standard Terms and Conditions of Contract attached to this enquiry document. Any particular terms included in this section shall take precedence over the Standard Terms and Conditions.

2.3.1. Invitation to Tender

The Example substation is being introduced in order to provide a new 20kV network connection point by cutting into an existing 110kV overhead line circuit to provide two new feeds from the 110kV network The actual load point at 20kV is some 5kms distant from the 110kV connection substation. This specification is issued as a functional specification and consequently there is no defined single line diagram or layout. It is the responsibility of the Tenderer to respond to all of the functional requirements defined for this substation, whilst taking full account of the defined Boundary conditions, in the most cost effective way. The substation is scheduled to be completed within eighteen months of the placement of order.

*The adjudication of the Tender will be made in accordance with the Evaluation Criteria given in Chapter * of this specification. Firstly a check will be made to ensure that all of the Boundary requirements defined in Chapter 1 have been fulfilled. Then the required functionality, defined in Chapter 2, will be checked in terms of the ratings and reliability and availability data. The Tenderer is required to enter all of the data into the Evaluation formula, defined in Chapter 3, to calculate the total evaluated life cycle cost with exception of the Asset Owner Internal Cost(OAC) . These calculations will be checked by the Asset Owner to verify the correctness of the interpretation and calculations and completed with the AOC. As only pre-qualified Tenderers have been invited to tender, once any uncertainties have been resolved with any of the Tenderers, the contract will be awarded to the Tenderer who has fulfilled all of the requirements with the lowest evaluated price.*

The scope of supply includes the design, engineering, manufacture, supply, delivery to site and storage (if required), civil works, installation, commissioning and guarantee for the guarantee period of everything required to fulfil the functional requirements for the defined Example Substation.

The Tenderer's attention is also drawn to the mandatory requirement to provide a quotation for performing the future expansion defined in Section 2.1.1.3 of the Chapter 2 on Functional requirements. This quotation will be available for acceptance by the Asset Owner for a period of ten years from the date of award of this contract with

escalation in accordance with the formula given in the Standard Terms and Conditions attached.
It is also mandatory that the Tenderers provide a fixed and firm price for providing all necessary routine maintenance for the first 10 years after complete energisation-. It shall be at the choice of the Asset owner whether or not this maintenance contract is awarded.

2.3.2 Instructions to Tenderers

Tenderers are requested to submit their completed tender by noon on *the day of ***. The Tender shall consist of a return of each of the Chapters 1 to 4 with each page signed to acknowledge acceptance and compliance with the Boundary, Functional and Evaluation requirements as well as the Commercial Terms and Conditions.

2.3.2.1 Information to be provided with the Tender

This contract is based on a functional specification and consists of a turn-key delivery and the price shall be fixed. In addition to the *Equipment and Services Price Schedule the full data for completing the Evaluation formula shall be supplied together with the calculated value of the total life cycle cost derived by the formula.*
The Tenderer shall also include:

- short system description describing the main ideas of substation design and the reason behind it
- availability, input data and results
- stage by stage proposals and emergency return to service
- single line diagram (different stages shown, if any)
- strategic spare parts (included in fixed price for same time period as the Long Term Guarantee
- optional spare parts (unit prices)

2.3.2.2Alternative Offers

Normally only one submission will be made which will be the option which gives the lowest evaluated cost, however, if the Tenderer wishes to offer an alternative which has a higher evaluated cost, or which does not fully comply with the Boundary or Functional requirements, he shall explain in detail why this is being offered in terms of the advantages (financial and non financial) which such an offer gives to the Asset Owner. The Asset owner shall only consider this alternative if the Tenderer's evaluated price is the lowest.

2.3.2.3Bonds

Tenderers shall submit with their offer a Tender Bond to the value of 1% of the total evaluated cost from the Evaluation formula. This bond shall be returned to all Tenderers when the contract has been placed.
A Long Term Guarantee Bond to the value of 50% of the life cycle part of the evaluated cost (i.e. total evaluated cost minus the capital cost) shall be submitted at the time of complete energisation. This shall be in addition to any guarantee bond offered in lieu of retention.

2.3.2.4 Tenderer's Obligations

*The Tenderers shall be responsible for making themselves fully aware of all matters pertaining to the contract and no claim afterwards for ignorance of the full details shall be entertained. In order to do this it is expected that the Tenderer shall visit the site and requests for a site visit shall be addressed to Mr.****** at the Company's Head Office.*

*If during the course of preparation of the Tender some aspect is not clear to the Tenderer they shall submit their question to Mr. ****** for clarification. The question and the provided answer shall be sent to all Tenderers for their information.*

If the Tenderer wishes to clarify their interpretation of any aspect or if there is a minor deviation this shall be stated in the Schedule of Clarifications and Deviations stating clearly which aspect of the Boundary, Functional, Evaluation or Commercial items it refers to. The Asset Owner shall not be obliged to accept such Clarifications or Deviations but if they are considered unacceptable the Tenderer will be given the opportunity to remove this from his tender to avoid his bid from being disqualified.

In order to assist the Asset Owner in fully understanding the Tenderer's offer the Tenderer shall complete the attached technical schedules for the different types of equipment included within his offer. In particular the Tenderer will explain and justify the basis of the reliability data as included within the Evaluation formula.

The successful Tenderer shall provide all of the relevant information to support the Asset Owner in the application for Planning and Construction Licences and the award of the contract shall be subject to obtaining these licences. The introduction of the Construction File to the Authorities will be carried out by the Asset Owner.

If after contract award there is still a delay in obtaining the Construction Licence jeopardising the contractual planning, the contractor can request a price adjustment conform the commercial Terms and Conditions. In case of refusal of the Construction Licences or specific request for modification by the authorities, the contractor can be request compensation for the services carried out

2.3.3 Special Terms and Conditions

2.3.3.1 Guarantee

There are two guarantees applicable to this contract.

2.3.3.1.1 Normal Plant Guarantee

As it is expected that the equipment or design of the substation to be offered on this Project will be novel, then a guarantee for repair or replacement of any faulty items shall apply for a period of five years from the date of energisation.

2.3.3.1.2 Guarantee of Evaluated Life Cycle Cost (Long Term Guarantee)

As the basis of the choice of contractor for this substation is based on an evaluated life cycle cost basis, then the Contractor shall guarantee the correctness of his calculated cost. The period of this guarantee shall be ten years being equal to the period of calculation of the life cycle part in the evaluation formula. Compliance with this requirement shall be calculated in the following way.

Any costs incurred which are applicable to terms within the formula shall be recorded at the actual cost and the date the cost is incurred will also be recorded. Each record will be approved by Asset Owner and Contractor. The value will then be discounted back to the date of energisation. Costs of losses will be calculated annually and discounted in the same way. At the end of the ten year period the sum of the discounted values will be compared with the figures submitted in the Tender. If the figure obtained is less than the figure submitted the Contractor shall be entitled to half of saving escalated back to the value at that time as a bonus. If the figure obtained is higher than the declared figure in the Tender then the Contractor shall pay half of the excess escalated to the value at that time as a penalty.

Note: If any circuit is unavailable because of the planned outage of, or failure of, equipment external to the substation, such as overhead lines or cables, these outages shall be recorded but the unavailability for such instances shall not be considered in the calculation of costs.

2.3.3.2Failure to fulfil the Boundary or Functional Requirements

If during the execution of the contract or during the Long Term Guarantee period it is found that any of the Functional or specific Boundary requirements have not been fulfilled, and these particular non compliances were not highlighted in the Tenderer's Schedule of Clarifications and Deviations, then the Contractor shall be obliged to fully rectify the non compliance at their own cost.

2.3.3.3Failure to Rectify Faults or Non Compliances

In case the contractor fails to carry out the required corrections the client has the right to employ other parties to carry out the necessary remedial works and charge the costs to the Contractor without invalidating the guarantee conditions. If, however, it is impractical to rectify the non compliances, the Asset Owner shall have the right to claim the additional costs caused by such non compliance for the period of the Long Term Guarantee.

2.3.4Payment Terms

The payment terms for the capital part of the contract shall be in accordance with the standard payment terms defined in the Standard Conditions of Contract. The retention shall be applicable to the end of the five year guarantee.

As the costs in the early years should be low a check calculation shall be made every two years to check that the costs are on target. If the costs appear to be excessive then the contractor shall pay half of the *excess to the Asset Owner at this time to avoid a very high payment becoming due at the end of the ten year period. These interim payments at their appropriate value will be taken into account in the final settlement account at the end of the ten year period. Any overpayments will be returned escalated back to the value at that time.*

2.3.5 Modifications to the Substation during the Long Term Guarantee period.

If the substation is modified or extended during the Long Term Guarantee period then the following conditions shall apply:-

a) If the work is the one that is foreseen as future work in this specification and is performed by the Contractor then there shall be no impact upon the Long Term Guarantee conditions. The particular conditions applicable to the new works shall be agreed at the time of contracting for these new works.

b) If the work is carried out by another contractor, then this part of the substation shall be treated as being external to the substation. Consequently, costs incurred by unavailability or other reasons associated with this equipment shall be excluded from the calculation of costs for the purpose of the Long Term Guarantee

Appendix A.4 Evaluation Example

Functional specification- Evaluation example

Note:
The example below is showing one way to handle comparison of bids. Price levels for equipment are assumed to Western Europe price level.
The bids will be adjudicated considering the following financial/economical evaluation formula:

EF = IC +AOC+ PMC + OC + PUC + UUC + EC + DC - B

The costs must be converted to an equivalent basis. This conversion should take the form of **capitalised cost calculation**, by using the present value formula except for extension costs and bonuses. Asset Owner must give the following information, which will enable solution provider to propose the most cost effective solution:

- **Time period** for which cost should be calculated *is assumed to be 30 years.*
- Specific **interest rate** to be used in calculation *is 5 per cent*.

The example proposed solutions are evaluated according to the given figures by Asset Owner, see below recapitulative table.

A. Data to be given by the utility to the solution provider	Given data	Unit
Average cost per man-hour of in-house labour	70	€ / hr
Cost per man-hour of contracted labour	50	€ / hr
Cost per man-hour of installation supervision	50	€ / hr
Cost per man-hour of testing labour (2 persons, not at the same time	60	€ / hr
Training costs, 4 persons	240	€ / hr
Rental or purchase of special equipment for maintenance	included in hourly rate	€ / hr
Cost for running losses per circuit		
- no-load losses	0.03	€ / kWh
- load losses	0.03	€ / kWh
Loss of revenue from planned downtime per maintenance occasion:	2000	€
- cost for power per circuit	included in the above	€ / kW
- cost for energy per circuit	included in the above	€ / kWh
- outage planning administration costs	included in the above	€
- customer / generation constraint penalties	included in the above	€
Loss of revenue from forced downtime, for each circuit:		
- cost for power	10000	€ /time
- cost for energy	1	€ / kWh
Cost of land	not included	€ / sqm
Time period for capitalised calculation	30	yr
Interest rate	5	%

Table 3: Recapitulative table given by Asset Owner

In Appendix A.5 a sensitivity analysis is made to investigate the effect of the evaluated cost for changes of the input parameters given in table 3. It is good to know, which factors have the greatest influence on the evaluated cost and see how much the evaluated cost is affected by changing these parameters.

2.4.1 Investment cost (IC)

Two different types of switchgear solutions have been considered.
H-type of switchgear using conventional Disconnectors and Circuit Breaker.
H-type of switchgear using innovative solution with Disconnecting CB.
[Solv00]
The two switchgear cases are shown in fig. 5. DCB is an apparatus that integrates both breaking and disconnecting functions in same apparatus.

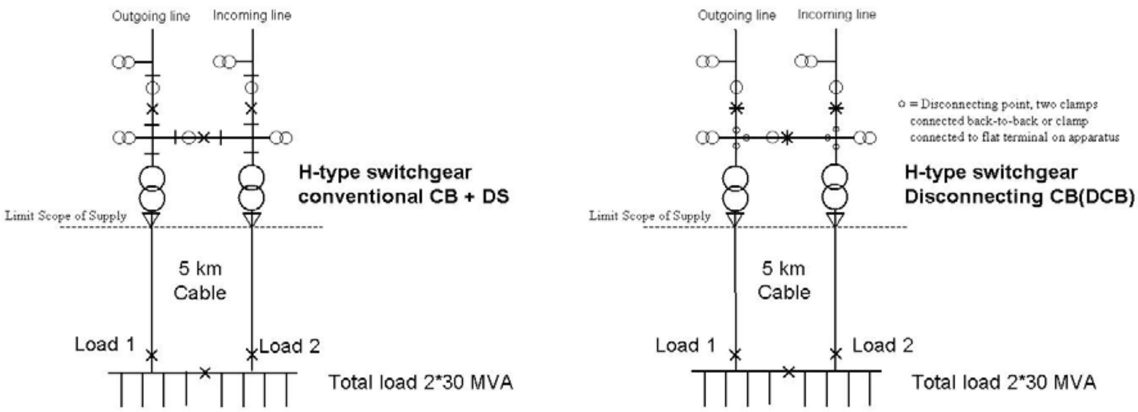


Fig. 5 Evaluated single line diagrams

In the functional requirement example it is required that max restoration time, for a fault in the substation causing outage of load 1 or load 2, shall be 48 hours. This will be fulfilled for switchgear faults and for minor faults on the power transformers. However for a severe power transformer fault the repair time will be much longer and there are therefore two choices regarding sizes of power transformers.

One alternative is to choose power transformer sizes such that one unit can take the full load of both load 1 and load 2. For a severe fault the remaining power transformer can take the full load of load 1 and load 2 during repair of the faulty unit. Another alternative is to choose transformer sizes such that one unit can take load 1 or load 2 only. A third unit then must be kept as a spare prepared to be used during a possible repair of one of the ordinary power transformers. The spare unit can be kept at a central location and possible also be used as spare for other similar substations in order to give a more cost effective solution.

Four cases are evaluated, two types of switchgear solutions and two sizes of power transformers.

Case 1: Switchgear using conventional Disconnectors and Circuit Breaker with power transformers 2*30 MVA + one spare 30 MVA power transformer.

Case 2*: Innovative solution using Disconnecting CB with power transformers 2*30 MVA + one spare 30 MVA power transformer.*
Case 3*: Switchgear using conventional Disconnectors and Circuit Breaker with power transformers 2*60 MVA.*
Case 4*: Innovative solution using Disconnecting CB with power transformers 2*60 MVA.*

Investment cost for 110 kV switchgear + Power Transformers 110/20 kV + 20 kV cable sealing ends (Medium voltage cables and switchgear are not included in this delivery)
Case 1: 2.43 M€
Case 2: 2.36 M€

Case 3: 2.73 M€
Case 4: 2.66 M€

2.4.2 Asset Owner Internal Costs (AOC)

a) Fixed Costs

These are assumed to be the same for both cases. It is assumed to be approximate 8% of the investment cost and not included in the evaluation. The Asset Owners in the task force estimate this figure.

b) Variable Costs

These are calculated according to hourly rates in table 1 and number of hours is assumed to be according to table 2.

	Case 1	*Case 2*	*Case 3*	*Case 4*
Installation time	*500*	*450*	*500*	*450*
Testing time	*80*	*60*	*80*	*60*
Training time	*60*	*75*	*60*	*75*

Table 4: Estimated hours for Asset Owner

It is assumed that power transformer sizes will not affect Asset Owners time at site. Further it is assumed that conventional solution will require a little more testing time (air insulated disconnectors) but a little less training since the equipment is of already existing type.

Asset Owner Variable costs are
Case 1: 44.2 k€
Case 2: 44.1 k€

Case 3: 44.2 k€
Case 4: 44.1 k€

2.4.3 Capitalised Costs for Planned Preventive Maintenance (PMC)

This cost is based on the level of required maintenance for the new equipment (maintenance plans): for each maintenance task. The calculation is based on the cost per man-hour of in-house labour or of contracted labour *given in Table 1, rental of special equipment is assumed to be included in the hourly rate.*

These capitalised costs are calculated for each maintenance task all along the life cycle time considered in this calculation. The cost is considering required maintenance frequencies, and then summed up according to present value formula.

Case 1 and case 3 *solutions have the following maintenance requirements:*
*Year 4: 2*20 hours, (Power Transformer) = 4 kε.*
*Year 5: 8*4 hours, (Disconnectors) = 3.2 kε.*
*Year 8: 2*20 hours, (Power Transformer) = 4 kε.*
*Year 10: 8*4 hours, (Disconnectors) = 3.2 kε.*
*Year 12: 2*20 hours, (Power Transformer) = 4 kε.*
*Year 15: 8*4 hours + 3*10, (Disconnectors + Circuit Breakers) = 6.2 kε.*
etc.
giving a total capitalised cost of 53 k€ for 30 years.

Case 2 and case 4 *solutions have the following maintenance requirements:*
*Year 4: 2*20 hours, (Power Transformer) = 4 kε.*
*Year 8: 2*20 hours, (Power Transformer) = 4 kε.*
*Year 12: 2*20 hours, (Power Transformer) = 4 kε.*
*Year 15: 3*10, (Disconnecting Circuit Breakers) = 3.0 kε.*
etc.
giving a total capitalised cost of 34 k€ for 30 years.

2.4.4 Capitalised Operation Costs (OC)

Running losses in transformers, shunt reactors, etc.
Case 1 and 2*: Each Power Transformer (30 MVA three-phase design) has no load losses of 19 kW and load losses of 94 kW at full load (30 MVA).*
Case 3 and 4*: Each Power Transformer (60 MVA three-phase design) has no load losses of 32 kW and load losses of 160 kW at full load (60 MVA).*

Cost for no load and load losses is 0.03 €/kWh according to table 3. The capitalised cost for the losses is shown in fig. 6.

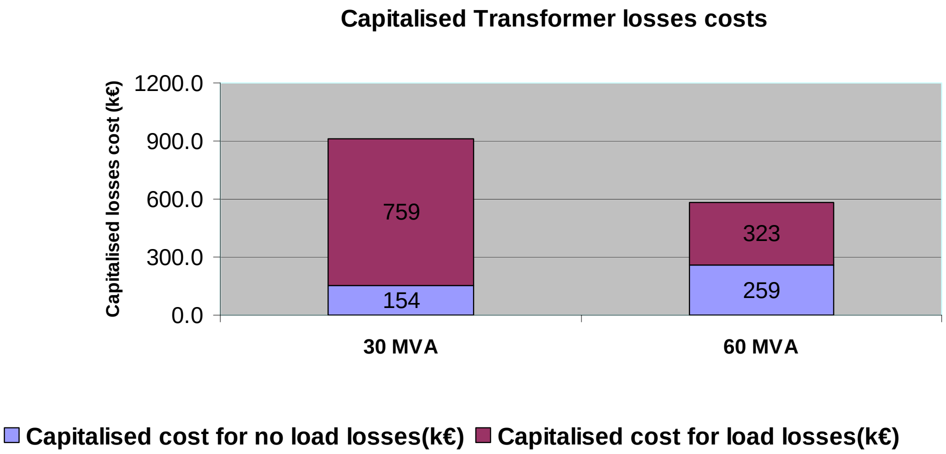


Fig. 6 Capitalised cost for transformer losses

With the assumed load profile with constant 30 MVA load 100 % of the time, the losses cost will be significantly higher for the 30 MVA size power.

*Investment cost for 2 units 60 MVA size power transformers are 2*570 k€ and 3 units 30 MVA 3*350 k€. Cost for losses is 331 k€ lower for the larger size of power transformers. This means investment and operation cost for 60 MVA is about 240 k€ lower compared to 30 MVA including spare unit.*

*Total investment and operation cost for 2*30 MVA is 110 k€ lower than 2*60 MVA. This means that if the spare unit can be shared between four or more substations the total investment and operation cost with 30 MVA size is lower. Severe transformer faults occur very seldom and the cost for the extra work to get the spare unit to site is minor.*

With a less constant load profile the capitalised losses for the smaller power transformers will also be lower and make this solution more attractive.

The difference between the solutions must also consider the cost for unplanned unavailability and if this is important the larger size power *transformer might be the preferred choice. Regarding unavailability cost please see more details in section 2.4.5.*

Note: General about unavailability calculations made

Unavailability calculations have been done for the proposed solutions.

Maintenance frequency and duration, requiring the primary circuit to be taken out of service, is taken from manufacturers operation and maintenance manuals for the included type of components.

Failure frequency and repair times are taken from CIGRE and CEA (Canadian Electric Association) statistic see table 5. [CEA93][Cigre13.94][Nordel]

Apparatus	FR [1/y]	MTTR [h]	MF [1/y]	MD [h]	MD + Breaks [h]	Source of the reliability number (FR)
CIRCUIT BREAKER	0.0068	12+2.5+4 (**)	0.0667	10	10	2 nd CIGRE inquiry on CB, major failures all period, 100-200 kV, see table 2.9.2.1 sheet 19
POWER TRANSFORMER	0.0335	15+2.5+4 (**)	0.25	20	32	CEA 1993-1997, trafo all tank arrangements, 110-149 kV, all integral subcomponents, page 84. MD+ Breaks is assuming 10 hours work + 12 hours night rest + additional 10 hours work.
DISCONNECTOR	0.001567 (*)	8+2.5+4 (**)	0.2	4	4	CEA 1993-1997, CB all interruption media, 110-149 kV, page 106
CURRENT TRANSFORMER	0.0005 (*)	6+2.5+4 (**)	0.00	0	0	CEA 1993-1997, CB all interruption media, 110-149 kV, page 106
VOLTAGE TRANSFORMER	0.001	6+2.5+4 (**)	0.00	0	0	CEA 1993-1997, CB all interruption media, 110-149 kV, page 106
BUSBAR	0.0082	6+2.5+4 (**)	0.00	0	0	CEA 1993-1997, CB all interruption media, 110-149 kV, page 106. For our small S/S busbar faults is assumed to be 25% of this figure for each "corner" of substation, i.e. that total failure rate busbar faults for ring
SURGE ARRESTER	0.0004	6+2.5+4 (**)	0.00	0	0	CEA 1993-1997, CB all interruption media, 110-149 kV, page 106
DISCONNECTING CB	0.0068	12+2.5+4 (**)	0.067	10	10	Using same figures as for conventional CB. Disconnecting CB is a conventional CB modified to be able to mechanical lock in the open position when used as a disconnector.

(*) The CEA AIS enquiry give failure rates per CB bay. Considering that normally each CB bay has 2 to 4 disconnectors, 2 earthing switches and 1 current transformers, the failure rate for disconnector was obtained dividing by 3 the original failure rate obtained by the multiplication of table All interrupting media 110 - 149 kV, the failure rate for the earth switch dividing by 2 and the failure rate for current transformer is equal to the value on the statistics.

(**) Mean time to repair (MTTR) time consist of time for repair + mean time to switch + time to get spares to site.

Table 5: Input data for unavailability calculation

For power transformers the repair time is only of importance for the smaller size (30 MVA). With power transformers of size 60 MVA one power transformer can take the full load independent of repair time. Time to repair is the mix between time to repair minor failures and exchanging power transformer for a major failure.

Unavailability calculation program SUBREL (SUBstation RELiability) has been used for the calculation. SUBREL has an automatic failure mode and effect analyses (FMEA). For making an unavailability calculation corresponding single line diagram for solution to be investigated together with apparatus maintenance and fault data is entered into the program. SUBREL then takes care of the FMEA and give the corresponding unavailability as output.

2.4.5 Capitalised Costs for Planned Unavailability (PUC)

These calculations give the unavailability of feeding to

- medium voltage cable on 20 kV side of power transformers, which is defined as "supply function"

due to planned maintenance of the apparatus in the substation. Maintenance on equipment outside substation is not included in this calculation.

Cost for planned unavailability can generally be split up in two parts,
***First part**: cost per power unit (ε/kW) × power interrupted (kW).*
***Second part**: cost per energy unit (ε/kWh) × power (kW) × time (hr).*

First part is a fixed cost independent of the outage time and only dependent on the power that is interrupted and the assumed cost per power unit. This part can be seen as the cost for Asset Owner to plan the outage, make necessary operating changes of the network due to the outage, etc. The reason to have the cost proportional to the interrupted power is that with increasing power the cost for planning, operational changes etc. also will increase.

Second part is the cost related to the energy that would pass through the circuit that is to be maintained. Maintenance usually can be done during low load situations in the network and then consumers could be supplied via a parallel path in the substation and/or from another source. Even when consumers are supplied via alternative source/path during the maintenance it could be that losses and/or generating cost would be higher than normal and then this figure could be put in here.

For evaluation of this specific example, following costs have been assumed:

- *first part is assumed to be 2 k€ per maintenance occasion independent of the size of power interrupted.*
- *second part is assumed to be zero cost for Asset Owner. It is assumed that maintenance can be done at a time when one power transformer can supply the full load.*

Due to these assumptions the capitalised cost for the planned unavailability will be of minor importance, however if load can not be supplied during maintenance this cost will be much higher.

***Case 1 and case 3** solutions have the following maintenance requirements:*
Year 4: (Power Transformer) = 2 kε.
Year 5: (Disconnectors) = 2 kε.
Year 8: (Power Transformer) = 2 kε.
Year 10: (Disconnectors) = 2 kε.
Year 12: (Power Transformer) = 2 kε.
Year 15: (Disconnectors + Circuit Breakers) = 2 kε.
etc.
giving a total capitalised cost of 12 k€ for 30 years.

***Case 2 and case 4** solutions have the following maintenance requirements:*
Year 4: (Power Transformer) = 2 kε.
Year 8: (Power Transformer) = 2 kε.
Year 12: (Power Transformer) = 2 kε.
Year 15: (Disconnecting Circuit Breakers) = 2 kε.
etc.
giving a total capitalised cost of 8 k€ for 30 years.

2.4.6 Cost for Unplanned Unavailability (UUC)

Unavailability calculations for unplanned unavailability (faults) have been done for unavailability of feeding to:

- *medium voltage cable on 20 kV side of power transformers, which could be defined as "supply function" of substation.*

- *outgoing 110 kV line, i.e. "feeding between incoming and outgoing lines in substation", which could be defined as "transfer function".*

***Note:** The transfer function is not required in the functional requirement since it is assumed that next substation has feeding from an alternative source if feeding through example substation should be broken. It could however be interesting to know how much cost this represents in case that alternative source is not available. Cost for the transfer function is thus not included in the LCC-cost for the example substation but only given as information in .sensitivity analyses in Appendix A5.*

The unavailability calculated is due to faults on the apparatus in the substation. Faults on equipment outside substation are not included in this calculation.

Cost for unplanned unavailability can generally be split up in three parts,
***First part**: cost per power unit (ε/kW) × power interrupted (kW).*
***Second part**: cost per energy unit (ε/kWh) × power (kW) × time (hr).*
***Third part**: Corrective maintenance cost.*

First part
First part is a fixed cost independent of the outage time and only dependent on the power that is interrupted and the assumed cost per power unit. This part can be seen as the cost for Asset Owner to send people to site for investigating fault, take necessary actions to isolate the fault, restore power to loads by reconfiguration, get hold of people and material for the repair/exchange of the faulty equipment, planning of the work etc. The reason to have the cost proportional to the interrupted power is that with increasing power the cost for this work will also increase.

Second part
Second part is the cost related to the energy that would pass through the faulty circuit until load has been restored. Faults are unpredictable and can happen at any time, however time between faults are quite long. For the calculation of cost for non-supplied energy average outage time per

year is used.

Third part

Third part is the cost for the labour and spare parts when making the repair. These costs have not been evaluated in the example work.

Cost assumptions and results for the specific example

For evaluation of the example, following costs have been assumed:

- *first part is assumed to 10 k€ per fault occasion independent of how much load that is interrupted.*
- *second part is assumed 1€/kWh*
- *third part is not evaluated in the example.*

***Note**: The estimated failure rates of components used as input in calculation shall be given by Solution Provider see table 5.*

The unavailability cost and the number of years to be considered in the cost calculation are given by the Asset Owner; see table 3 and these will be multiplied by the calculated unavailable hours/year.

Unavailability due to the substation equipment shall be considered here, not unavailability due to faults on external circuits to the substation.

Unavailability results from SUBREL calculation are as follows:

Case 1:

	Outage Freq.: /yr	Outage duration h/yr	Outage duration h/yr
	Normal State Faults	Normal State Faults (Switchgear)	Normal State Faults (Transformer)
Feeding of one 20 kV load	0.1041	0.2759	1.4375
Feeding of both 20 kV load	0.0068	0.0170	0.0000

Case 2:

	Outage Freq.: /yr	Outage duration h/yr	Outage duration h/yr
	Normal State Faults	Normal State Faults (Switchgear)	Normal State Faults (Transformer)
Feeding of one 20 kV load	0.0945	0.1578	1.4375
Feeding of both 20 kV load	0.0068	0.0238	0.0000

Case 3:

	Outage Freq.: /yr	Outage duration h/yr	Outage duration h/yr
	Normal State Faults	Normal State Faults (Switchgear)	Normal State Faults (Transformer)
Feeding of one 20 kV load	0.0000	0.0000	0.0000
Feeding of both 20 kV load	0.0068	0.0170	0.0000

Case 4:

	Outage Freq.: /yr	Outage duration h/yr	Outage duration h/yr
	Normal State Faults	Normal State Faults (Switchgear)	Normal State Faults (Transformer)
Feeding of one 20 kV load	0.0000	0.0000	0.0000
Feeding of both 20 kV load	0.0068	0.0238	0.0000

Unplanned unavailability (faults) outage cost for supply function, is due to fault in both switchgear and power transformer. In order to see what part of substation equipment the unavailability cost is related to, the cost is split up in cost due to faults in power transformer and switchgear.

Unplanned unavailability cost due to power transformer faults are:

Case 1: 597 k€
Case 2: 597 k€

Case 3: 0 k€
Case 4: 0 k€

Unplanned unavailability cost due to switchgear faults are:
Case 1: 146 k€
Case 2: 101 k€

Case 3: 15 k€
Case 4: 21 k€

2.4.7 Extension Costs (EC)

The Solution Provider shall give an optional price for extensions of the substation valid e.g. for 10 years, also taking into account interest rate, etc.

Extension costs have not been evaluated in the example work.

2.4.8 Capitalised Costs for Decommissioning (DC)

This is the costs of dismantling and waste handling of substation material at the end of substation life.
Salvage value of dismantled equipment (income) should also be considered in the calculation of this cost.

The Asset Owner must judge the above two factors based on previous experience on his network for estimating the net DC costs.

For this example capitalised cost for decommissioning is assumed to be 8% of the investment cost.

Capitalised costs for decommissioning are:
Case 1: 48 k€
Case 2: 46 k€

Case 3: 49 k€
Case 4: 48 k€

Salvage value of old equipment is included when choosing above percentage factor for decommissioning costs.

2.4.9 Bonuses (B)

This consists of possible bonuses the Asset Owner wants to use (specified in the technical specification).

As no Bonus was specified in the Boundary Proforma example Bonus costs have not been evaluated in the example work.

2.4.10 Other Aspects (that are taken into consideration in evaluation of the tenders)

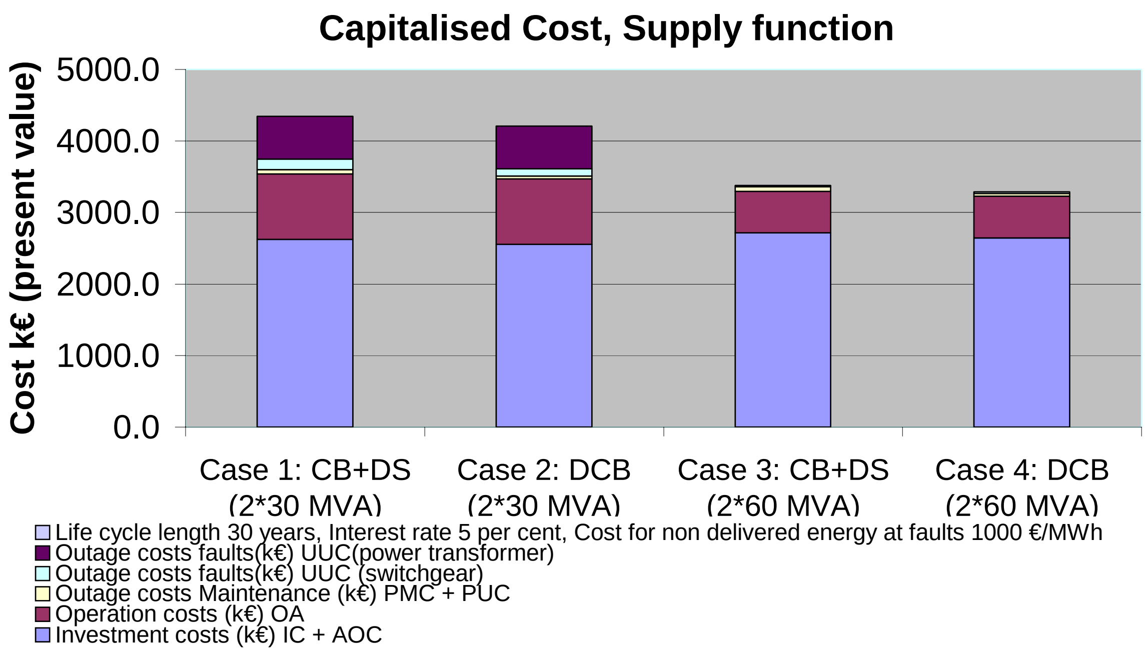
The Asset Owner may specify other factors that he wants to be considered in the evaluation of the Tenders, such as:

- consideration of Tenderer's earlier experience in similar works, merits, organisation, plant facilities and financial resources
- consideration of client's earlier experience of Tenderer's similar deliveries regarding technical merits, quality, reliability, after-sales services, meeting delivery dates etc.
- consideration of other aspects of the tendered solution: quality, reliability, availability of spares, environmental impact, safety aspects
- other risks, political etc.

These aspects have not been evaluated in the example work. They are however of great importance and already in use by Asset Owners during "normal" tendering process. For functional specification tenders they should be applied similar to "normal" tenders.

Summary

The sum of all cost when evaluated the example proposed solutions according to asset owner recapitulative table are shown in fig. 7. Please note that this evaluation is only for substation task as supply function, i.e. feeding to load 1 and load 2 on 20 kV side of power transformers. This is per functional requirements given by the asset owner.



	Investment costs (k€)	Operation costs (k€)	Outage costs Maintenance (k€)	Outage costs faults(k€)	Outage costs faults(k€)	Decommissioning costs (k€)	Sum of all costs
	IC + AOC	OA	PMC + PUC	UUC (switchgear)	UUC(power transformer)	DC	k€
Capitalised cost supply function							
Case 1: CB+DS (2*30 MVA)	2624	913	65	146	597	48	4393
Case 2: DCB (2*30 MVA)	2554	913	42	101	597	46	4253
Case 3: CB+DS (2*60 MVA)	2714	582	65	15	0	49	3426
Case 4: DCB (2*60 MVA)	2644	582	42	21	0	48	3337

Fig. 7 Total capitalised cost for substation supply function given as diagram and table

Substation transfer function, i.e. transferring power from the incoming 110 kV line to the outgoing 110 kV line is not included in the evaluation of the example solutions. This aspect will add additional outage costs and will be discussed in appendices A5.

Observations:

Power transformer unavailability due to faults

Major part of the unavailability costs for solution with 30 MVA transformers is due to transformer failures. Failure rate for power transformers are coming from Canadian statistic, which was used in the evaluation due to its good coverage of all included apparatus.
However in statistic from Nordel (the Nordic countries Denmark, Sweden, Norway, Finland and Iceland) during the years 1986-1995 (15 000 apparatus years) the failure rate is 0.015 per hundred year, which is about half compared with the used Canadian statistic.
The calculated outage cost due to transformer failures should therefore be handled with care. The main purpose of this study was to compare different switchgear solutions with respect to total capitalised cost of substations. The "problem" with the high outage cost due to power transformer failures was discussed in the Task Force and Working Group. It came up a proposal to ignore power transformer failures in this study to show more clearly the

difference between switchgear solutions. Decision in Working Group was to include power transformer failures since there exists no power transformers without failures.

Switchgear faults effects on 20 kV loads depends on power transformer size

For the cases with power transformers of 60 MVA size the only switchgear fault that will cause outage of any 20 kV load are a fault on the 110 kV bus-section circuit breaker. For all other switchgear faults both 20 kV loads are unaffected and kept in service.

To see how the different 110 kV switchgear solutions affect unavailability of 20 kV loads the cases with 30 MVA power transformers should be compared. For cases with 60 MVA power transformer sizes, 110 kV switchgear availability differences can not be seen due to this.

A.5 Sensitivity Analyses of the Capital Cost Calculation

In appendix A4 two switchgear solutions, each with two different sizes of power transformers giving four cases altogether, were evaluated according to values given by the Asset Owner, see table below.

A. Data to be given by the utility to the solution provider	Given data	Unit
Average cost per man-hour of in-house labour	70	€/hr
Cost per man-hour of contracted labour	50	€/hr
Cost per man-hour of installation supervision	50	€/hr
Cost per man-hour of testing labour (2 persons, not at the same time	60	€/hr
Training costs, 4 persons	240	€/hr
Rental or purchase of special equipment for maintenance	included in hourly rate	€/hr
Cost for running losses per circuit		
- no-load losses	0.03	€/kWh
- load losses	0.03	€/kWh
Loss of revenue from planned downtime per maintenance occasion:	2000	€
- cost for power per circuit	included in the above	€/kW
- cost for energy per circuit	included in the above	€/kWh
- outage planning administration costs	included in the above	€
- customer / generation constraint penalties	included in the above	€
Loss of revenue from forced downtime, for each circuit:		
- cost for power	10000	€/time
- cost for energy	1	€/kWh
Cost of land	not included	€/sqm
Time period for capitalised calculation	30	yr
Interest rate	5	%

Table 3: Recapitulative table given by Asset Owner

Sensitivity calculation is made in this section. This is done in order to see how much the total capital evaluated cost and the relation between the different parameters included is affected by changes on the input parameters.

The formula for evaluation is built up of the following parameters using the present value formula:

EF = IC +AOC+ PMC + OC + PUC + UUC + EC + DC - B

In the capitalised evaluated cost on the following pages cost is split up in three parts:

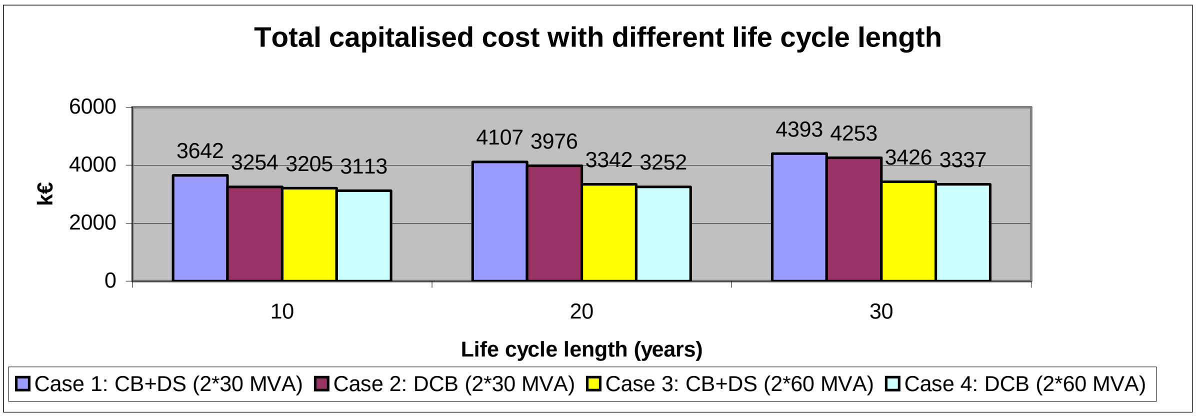
- Investment cost, which include IC+AOC. For solution with 30 MVA power transformer 3 units are included.
- Operation Cost, which include OC.
- Outage Cost, which include PMC+PUC+UUC, i.e. unavailability costs due to maintenance and faults on primary equipment.

A5.1 Effect of Variation of Substation Life Cycle length on total evaluated cost

The time period for capitalised calculation is 30 years in the example evaluation. This can be assumed to be the approximate physical life length of the included high voltage equipment. This would be the most appropriate lifetime to consider for those cases where the Asset Owner is for example an established utility and will stay in the market for longer than 30 years.

With the deregulation of the electricity market and new players on the Asset Owner side, with contract of type IPP, BOT etc., the Life Cycle for evaluation could be shorter than the physical life length of the equipment. This may lead to the requirement that the cost of equipment be evaluated for a shorter time than the actual lifetime of the equipment.

Calculation of total capitalised cost for 10 years, 20 years and 30 years respectively is shown in table below.



Split up of the included in cost in percent of the total cost is shown in below table:

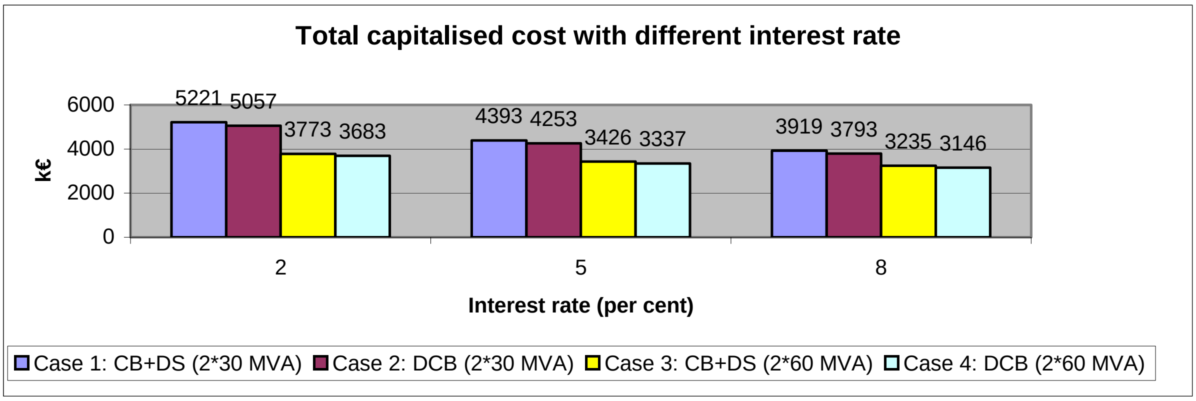
Case 1 split up of cost	Investment cost	Operation cost	Outage cost
10 year	72%	13%	12%
20 year	64%	18%	16%
30 year	60%	21%	18%
Case 2 split up of cost	Investment cost	Operation cost	Outage cost
10 year	78%	14%	12%
20 year	64%	19%	15%
30 year	60%	21%	17%
Case 3 split up of cost	Investment cost	Operation cost	Outage cost
10 year	85%	9%	2%
20 year	81%	14%	2%
30 year	79%	17%	2%
Case 4 split up of cost	Investment cost	Operation cost	Outage cost
10 year	85%	9%	2%
20 year	81%	15%	2%
30 year	79%	17%	2%

As expected the investment cost will be a more dominant factor of the total Life Cycle cost with a shorter evaluating time.

A5.2 Effect of Variation of Interest Rate on total evaluated cost

The interest rate is 5 % in the example capitalised cost calculation.

Calculation of total capitalised cost for 2 %, 5% and 8% interest rate respectively is shown in the table below.



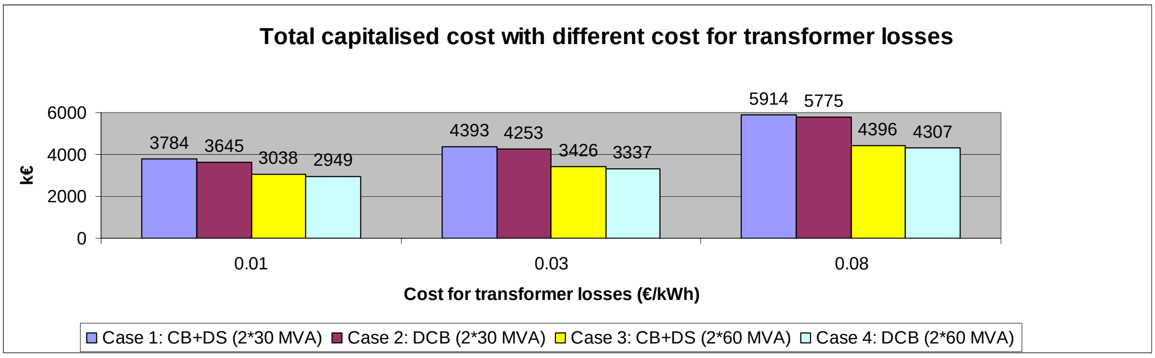
Case 1 split up of cost	Investment cost	Operation cost	Outage cost
2 % interest	50%	25%	22%
5 % interest	60%	21%	18%
8 % interest	67%	17%	15%
Case 2 split up of cost	Investment cost	Operation cost	Outage cost
2 % interest	51%	26%	21%
5 % interest	60%	21%	17%
8 % interest	67%	18%	15%
Case 3 split up of cost	Investment cost	Operation cost	Outage cost
2 % interest	72%	22%	2%
5 % interest	79%	17%	2%
8 % interest	84%	13%	2%
Case 4 split up of cost	Investment cost	Operation cost	Outage cost
2 % interest	72%	23%	2%
5 % interest	79%	17%	2%
8 % interest	84%	14%	2%

The investment part of the Life Cycle cost decreases and operation and outage costs are increasing with lower interest rate.

A5.3 Effect of Variation of Cost for Losses on total evaluated cost

The power transformer losses are assumed to cost 0.03 €/kWh in the example capitalised cost calculation.

Calculation of the total capitalised cost for cost of losses of 0.01 €/kWh, 0.03 €/kW and 0.08 €/kWh respectively is shown in the table below.



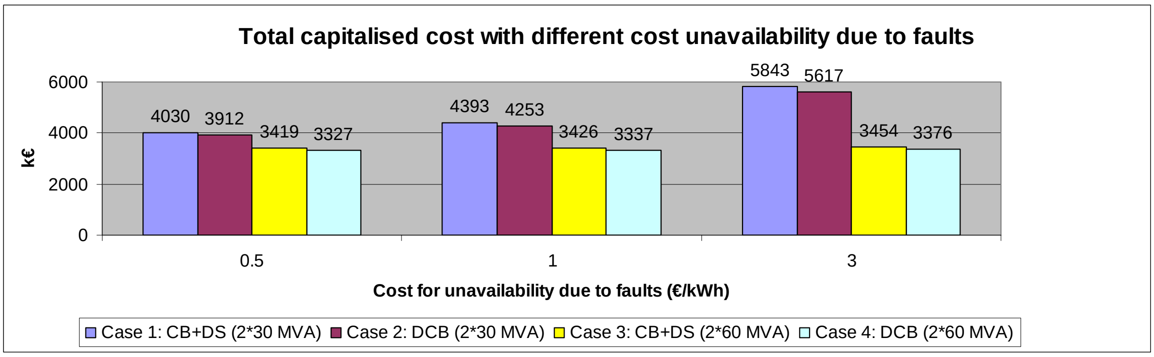
Case 1 split up of cost	Investment cost	Operation cost	Outage cost
0.01 €/kWh losses	69%	8%	21%
0.03 €/kWh losses	60%	21%	18%
0.08 €/kWh losses	44%	41%	14%
Case 2 split up of cost	Investment cost	Operation cost	Outage cost
0.01 €/kWh losses	70%	8%	20%
0.03 €/kWh losses	60%	21%	17%
0.08 €/kWh losses	44%	42%	13%
Case 3 split up of cost	Investment cost	Operation cost	Outage cost
0.01 €/kWh losses	89%	6%	3%
0.03 €/kWh losses	79%	17%	2%
0.08 €/kWh losses	62%	35%	2%
Case 4 split up of cost	Investment cost	Operation cost	Outage cost
0.01 €/kWh losses	90%	7%	2%
0.03 €/kWh losses	79%	17%	2%
0.08 €/kWh losses	61%	36%	1%

The power transformer losses are the major part of the operation cost of a substation with a "transforming" function. With the increasing energy costs that we have seen in recent years this will be even more pronounced. The Asset Owners should be aware of this and check and possibly change their evaluation formulae for power transformers.

A5.4 Effect of Variation of Cost for Unavailability due to Faults on total evaluated cost

The cost for unavailability due to faults of the primary apparatuses (UUC) is assumed to be 1 €/kWh in the example capitalised cost calculation.

Calculation of total capitalised cost for unavailability 0.5 €/kWh, 1 €/kW and 3 €/kWh respectively is shown in the table below.



Case 1 split up of cost	Investment cost	Operation cost	Outage cost
0.5 €/kWh for faults	65%	23%	11%
1 €/kWh for faults	60%	21%	18%
3 €/kWh for faults	45%	16%	39%
Case 2 split up of cost	Investment cost	Operation cost	Outage cost
0.5 €/kWh for faults	65%	23%	10%
1 €/kWh for faults	60%	21%	17%
3 €/kWh for faults	45%	16%	37%
Case 3 split up of cost	Investment cost	Operation cost	Outage cost
0.5 €/kWh for faults	79%	17%	2%
1 €/kWh for faults	79%	17%	2%
3 €/kWh for faults	79%	17%	3%
Case 4 split up of cost	Investment cost	Operation cost	Outage cost
0.5 €/kWh for faults	79%	17%	2%
1 €/kWh for faults	79%	17%	2%
3 €/kWh for faults	78%	17%	3%

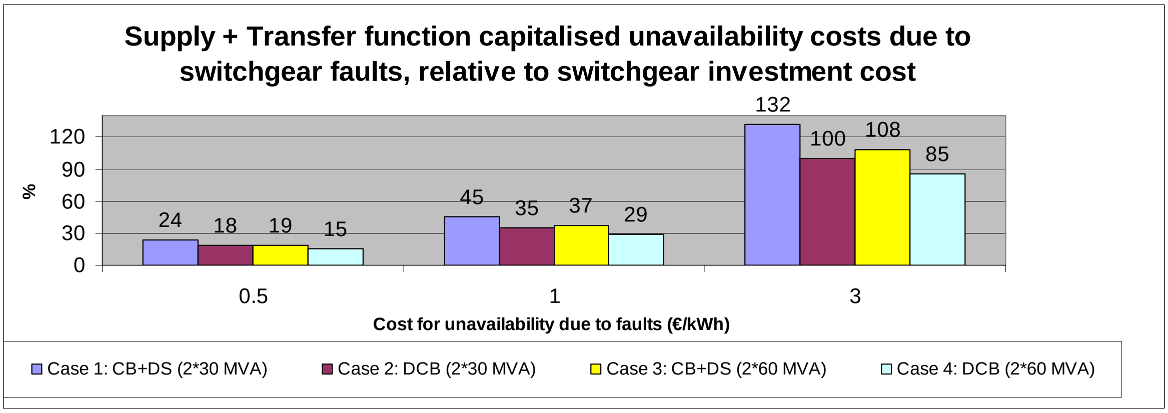
On current networks, the true cost of unavailability due to faults can be very high however today penalties, although discussed, are not often applied. If the cost of unavailability due to faults is genuinely very high then this should have a significant affect upon the design of the substation. On the other hand, if an unnecessarily high figure is used then this could result in a design which is more expensive than required.

A5.5 Effect of Unavailability Costs for Supply and Transfer Function on the total evaluated cost

In the example functional specification, the task of the substation was to supply power to 20 kV loads and to transfer power between incoming and outgoing 110 kV lines in order to feed "next" 110 kV substation. It was however assumed in the evaluation that "next" 110 kV substation can be fed via other sources if the transfer through the example substation is broken. Unavailability costs for the cases where a fault in the substation broke the connection (transfer) between the incoming and outgoing 110 kV lines were therefore not considered in the example evaluation.

For other cases it might be that 110 kV network is fed via a radial ring and the "next" substation cannot be fed via other sources if the transfer is broken in the example substation. In order to check how this would affect unavailability costs an evaluation is done considering unavailability of both supply (feeding to 20 kV) and transfer (feeding between incoming and outgoing 110 kV lines) function of the substation. Supply function is feeding two loads each of 27 MW and transfer function is feeding a load of 50 MW. Supply and transfer power is thus almost equal for this case.

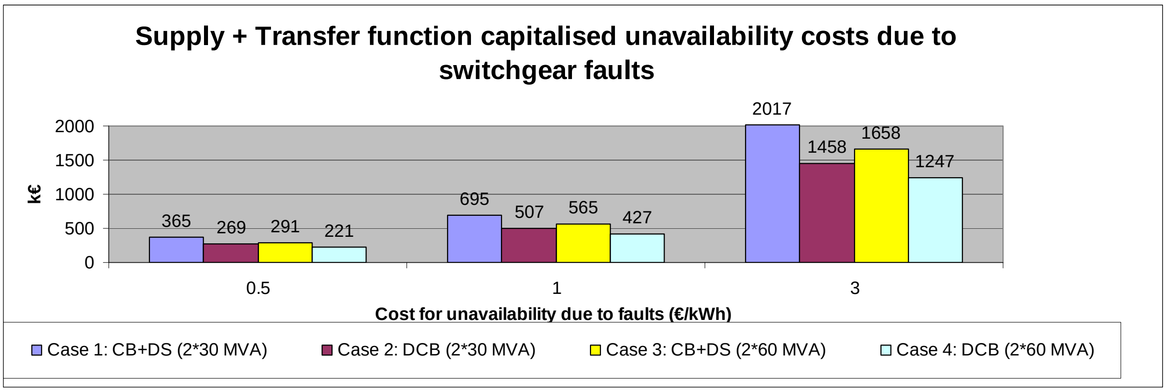
In the diagram below the capitalised unavailability costs for faults in the switchgear apparatuses in relation to the switchgear investment cost are shown, the cost of the power transformer and associated faults are excluded. Only unavailability due to faults is considered, unavailability due to maintenance is not included.



The percentage unavailability cost is quite large compared with the investment cost. It is therefore of the utmost importance to try to get availability as high as possible in the purchased switchgear.

As can be seen in the diagram above the innovative solution with Disconnecting Circuit-Breaker (DCB), cases 2 and 4, gives lower percentage unavailability costs compared with the solution with conventional Circuit-Breakers and Disconnectors. This is a promising result for this new type of technique.

In addition investment cost for DCB is lower than corresponding conventional alternative, which means that actual difference in unavailability costs is even larger. This can be seen in below diagram.



EVALUATION OF SUBSTATION CONCEPT

B1 Case Study

Note:

The case study below shows an evaluation of different substation concepts under certain requirements and circumstances. Under different requirements and circumstances, the evaluation may look different.

As a sample substation a typical H-arrangement in 145kV with three circuit breakers and cable connection has been chosen [DgLa03]. Scope of the case study is the high voltage switchgear equipment including control equipment and building without transformers and medium voltage cables and switchgear. Three different technical solutions are evaluated, **Figure 8**:

- Solution 1: GIS indoor
- Solution 2: GIS outdoor
- Solution 3 AIS

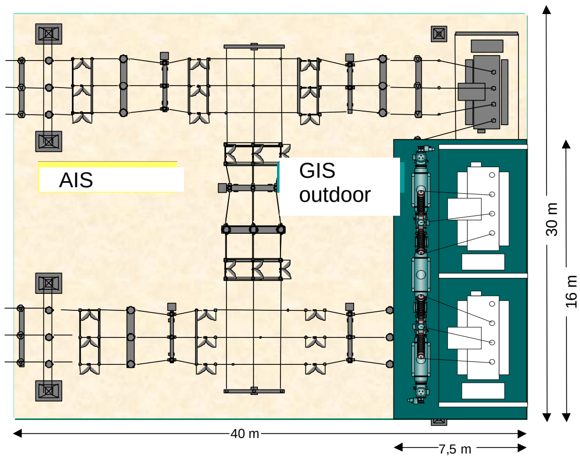


Figure 8: Sample substation arrangement for comparison and calculation of life cycle cost: 145kV H-arrangement with three circuit breakers (AIS and GIS outdoor solution. For GIS indoor the switchgear equipment will be installed in a building (not shown). Control buildings are included in the comparison (not shown).

B1.1 Economical Evaluation

1. Definition of life cycle phases of the substation and development of cost breakdown structure

First, the relevant life cycle phases and the economical values were identified (examples see **Section 3 table 2**). Planning, design and disposal costs were not considered, because their values do not differ considerably between the three solutions. In this case the focus was put on certain acquisition costs (system cost, land acquisition cost and installation cost) and certain ownership costs (operation, maintenance and outage cost).

2. Definition of product and work breakdown structure

For each solution a list of all pieces of equipment and all the steps of the process has to be defined. Scope of this case study is the high voltage switchgear and control equipment, without transformers and medium voltage switchgear and cables. If transformers are included in the scope of supply, investment costs and running losses should be considered (see Appendix A.4).

3. Estimation of cost

The estimation of acquisition cost is based on existing offers. The estimation of ownership cost is more difficult. Either the experiences of the ownership of comparable substations can be considered or existing statistics can be used. In this case study, service statistics were used for the estimation of outage and failure costs. **Table 6.** GIS equipment permits longer maintenance cycles, but incurs higher cost per event. Due to the encapsulation, GIS equipment has a lower failure rate than AIS equipment. Due to the higher integration of equipment the duration of downtime is longer for GIS. The data for GIS outdoor has been derived from the GIS indoor data as far as GIS technology is used and compared with Cigré data for encapsulated outdoor installations.

	Basic Parameters	**GIS indoor**	**GIS outdoor**	**AIS**
Key Data of analysed substation				
Voltage level, Arrangement	145kV, H-arrangement, 3 circuit breakers			
Time period for calculation	50 years			
Effective Interest Rate	7% (9% interest rate – 2% inflation rate)			
Operating cost				
Maintenance switchyard	2 €/m²/year***	800 €/a	1600 €/a	4000 €/a
Building maintenance	20 €/m²/year***	5000 €/a	1000 €/a	1000 €/a
Preventive Maintenance				
Interval between two maintenance cycles		8.1 yrs*	8.1 yrs* – 10%***	7.1 yrs*
Cost of maintenance per event (labour + travel + material)	80 €/h***	43.297 €	43,043 €	45,902 €
Corrective Maintenance / Outage Cost				
Failure rate per C.B.-years				0.68*
Percentage of Involvement of C.B. in major failures				34%**
Failure rate per C.B.-bay-years		1.37**	1.37** + 10%***	2.01
Repair time		218 h**	218 h**	121 h**
Average cost per major fail. (labour + travel + material)	80 €/h[3]	45,046 €	45,046 €	37,295 €
Percentage of outages (of major failures)		9%**	9%**	9%**
Duration of downtime		56 h**	56 h**	31 h**
Financial loss in case of interruption	2,5 ct/kWh + 10,000 €/h***			

Table 6: Table of key data for LCC calculation (data sources: *[cigre 94], **[cigre 00.2], *** estimation, assumption): N.B.: GIS outdoor assumed 10% less reliable.

This analysis focuses on the comparison of HV switchgear technologies. The following cost components have been considered:

System cost (cost of supplied system)

- switchgear, control & protection systems
- engineering of system supplier

Installation / Site preparation:

- transportation
- civil works (GIS building or control building)
- gantries, foundations, earthing, cable ducts
- installation / testing / commissioning

Transformers, MV switchgear – have not been considered.

Land acquisition cost has not been respected, because of the strong individual character of this parameter. However the influence of the land acquisition cost will be analyzed in the sensitivity analyses.

4. Summarise cost

Acquisition and operation cost are summarized. In this case the operation costs are capitalized. **Figure 9** shows the summarised cost and the comparison of the different solutions. The total life cycle cost of the AIS arrangement is taken as 100% for this comparison.

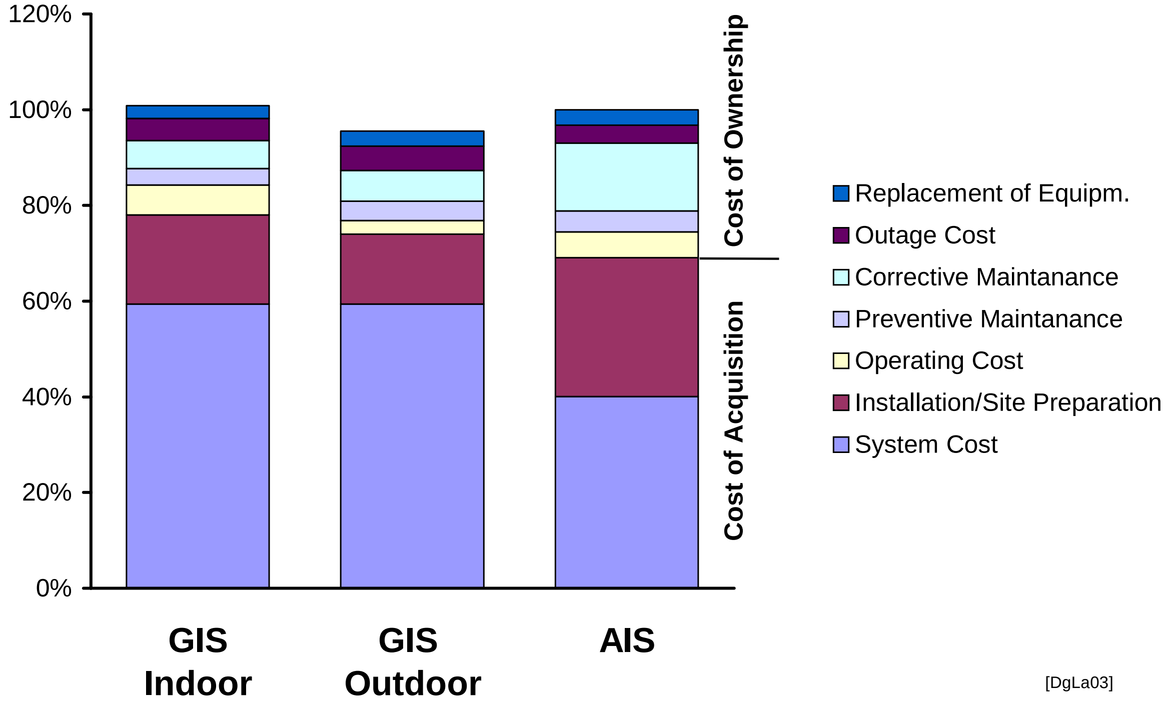


Figure 9: Comparison of cost structure of LCC of GIS and AIS for the 145kV sample arrangement.

5. Sensitivity analysis and optimisation potential

The calculation of life cycle cost directs the way to optimization of the high voltage substation design, therefore a simple calculation of the life cycle cost is not sufficient. It shall be shown how a sensitivity analysis of a sample arrangement realized in different technologies can be used to optimize the substation. It is important for the life cycle cost analysis to understand which influence of which parameter can be optimized and by what measure.

The sensitivity analysis is predicting the change of the overall life cycle cost if a specific parameter will be changed by 10% or land acquisition is considered, **Figure 10**.

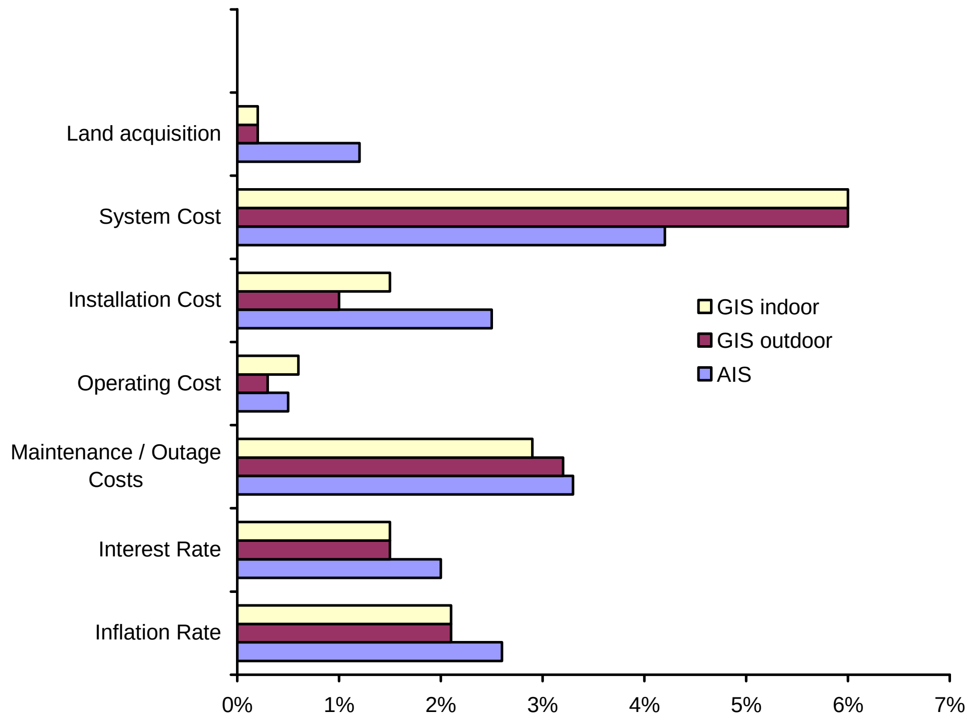


Figure 10: Sensitivity analysis of selected parameters of LCC calculation

Interpretation:

- The sensitivity of land acquisition cost is negligible for small surfaces required for the encapsulated GIS-technologies but has to be considered if land acquisition is necessary and land is expensive.
- The largest cost portion evidently has the biggest impact on the life cycle cost. This means that increasing the system cost by 10% will increase the life cycle cost of the sample substation in AIS technology by 4 %, in GIS technology by 6%.
- Installation costs have a smaller direct influence on life cycle cost, but indirect influence on the bigger cost portion of outage costs. In this case, it is recommended to choose high quality installation work, if the number of outages has to be reduced.
- The number of interruptions of energy flow due to a major failure has one of the strongest influences, stronger than the cost of preventive maintenance. Thus, a decrease of interruptions of energy flow achieved by better planned preventive maintenance can reduce the overall life cycle cost.
- Interest rates of capitalized cost also have a high sensitivity.

- The influence of interest and inflation rate of GIS is lower than AIS because the system portion which is independent of discounting or inflation for this type of switchgear is more dominant.

B1.2 Qualitative Evaluation

1. Definition of qualitative evaluation criteria along the life cycle

Life cycle thinking helps to gather important qualitative values (examples see **Section 3 table 2)**. This case study focuses on different switchgear technologies. Therefore, bidder and compliance values are not considered. Main emphasis is put on values of site preparation, operation and extension (community acceptance, EMF generated, safety, seismic tolerance and independence of interfaces).

2. Weighting of selected evaluation criteria

Out of the five values, the community acceptance is the most important (weight: 0,3) the independence of interfaces is considered least important (weight: 0,1). The other values are equal (weight: 0,2).

3. Evaluation of degree of realisation ranging from 0 to 1

The evaluation of the selected criteria was made with a six step scale (requirements not fulfilled, very low, low, medium, high, very high) from 0 to 1.

4. Determination of qualitative value

The qualitative value of a solution is the sum of all products of weight and values. In this case study, under the chosen values, the qualitative value of the GIS indoor solution is the highest, **Table 7**.

Table 7: Example of qualitative evaluation

		Solution 1 GIS Indoor		**Solution 2 GIS Outdoor**		**Solution 3 AIS**	
	Weight		Value		Value		Value
Community acceptance	0,3	High	0,8	Low	0,4	Very low	0,2
EMF generated	0,2	Low	0,8	Low	0,8	Medium	0,6
Safety	0,2	High	0,8	High	0,8	Medium	0,6
Seismic tolerance	0,2	Medium	0,6	Medium	0,6	Low	0,4
Independence of interfaces	0,1	Low	0,2	Low	0,2	Very High	1,0
	1						
Qualitative value			0,70		0,58		0,48

The evaluation criteria, their associated weights and their values are just an example. Many other combinations are possible according to the requirements of the Asset Owner. The application of this evaluation method always has to be connected to a specific project. A framework of further qualitative values is given in Section 3 Table 2.

B1.3 Overall Evaluation

The economical and qualitative values of the three solutions are put into a portfolio, **Figure 11**. In order to show significant differences, scales were chosen considering the extreme values: Life Cycle Cost between 100% (maximum) and 80% (minimum) and Qualitative Values between 0,4 and 0,8.

In this case study, the GIS-solutions are of higher overall value. The combined economical-qualitative value (or price-performance value) of the GIS-solutions are comparable. The decision makers have to decide, if the additional qualitative value justifies a higher life cycle cost.

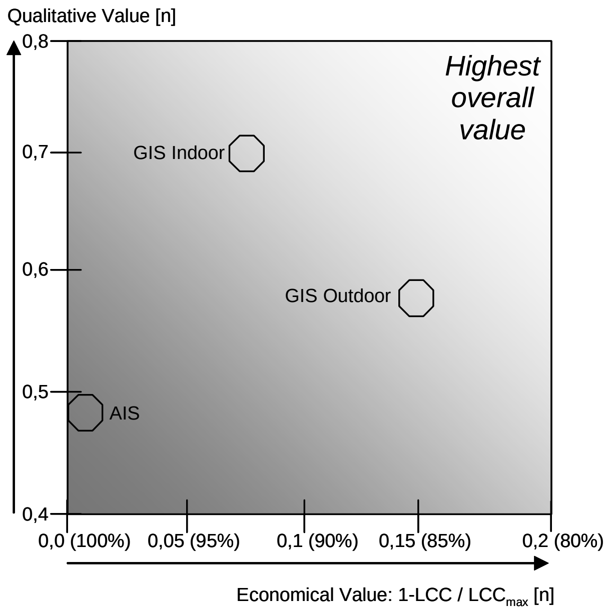


Figure 11. Example of portfolio for economical and qualitative evaluation