KEMA Limited

Ofgem

Technical Advisors for OFTO Tender Process:

Cost Efficiency Report

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Revision History

Rev.	Date	Description	Author	Checker	Approver
1.00	01 May 2009	First draft for discussion	IW/MF	DPop	DP
2.00	09 June 2009	Second draft for discussion on structure. Commentary will change when additional projects are added to the comparator metrics	MF/IW	DP	LP
3.00	09 June 2009	Final report	MF/IW	DP	LP
3.01	29 June 2009	Minor amendments to the final report	MF	IW	DP

Executive Summary

The Offshore Transmission Owner (OFTO) licensing process requires a Regulatory Asset Value (RAV) to be determined for each of the transitional projects. A key input to this RAV is an assessment of the capital cost information submitted by project developers to confirm economic efficiency.

The approach adopted by KEMA to assess developer capital cost submissions normalises the information[1], allocates it consistently to the main project components[2] of the offshore transmission system and also creates a set of comparator cost drivers that can be used as peer benchmarks. KEMA regards the peer comparators as the most useful indicators of reasonable costs as these relate to projects being developed over a similar timeframe, in the same regulatory and legal framework, with comparable economic drivers and a similar supplier base.

This report provides for each of the comparator metrics, a description, the derivation method and a commentary of the results. A subset of the comparator metrics, which drive 80-90% of the costs of the project, have been used to create Comparator Valuations for each of the following major cost elements:

- Offshore substation, consisting of the platform, electrical items (switchgear and transformers) and installation costs;
- Cable supply (the entire length of both submarine and land cable supply as these are often part of the same contract);
- Onshore reactive power compensation equipment, consisting of the plant and equipment that provides the reactive power control for the wind farm to meet technical requirements; and
- Capitalised development costs consisting of capitalised developer operating costs included in each project (e.g. land owner easements, consultancy, engineering, supervision, allocated overheads but excluding any enduring maintenance provision)

Further metrics have been derived to support the use of the cost drivers in this report. These consider alternative validation approaches for offshore substation costs and also seek to benchmark the costs of transformers (per MVA) as submitted by developers. These additional metrics reinforce the assessment of the main costs elements for each transitional project.

High-level indicators of the relative size, position and cost the transitional projects are shown in Figure 1 and Figure 2. These charts demonstrate how costs (as denoted by circle size) vary according to increasing transmission capacity and cable length. The first chart plots the Normalised Valuations and the second chart plots the Comparator Valuations which were derived using the cost comparator metrics described in

1 Based on submitted developer cost information excluding any elements relating to contingencies, project financing and project purchase costs.

2 The main components being the offshore substation, supply and installation of the submarine and land cables, onshore reactive power equipment and substation connection and development costs (capitalised operations costs, e.g. project management, overheads, leases and consents etc).

this report. For clarity, the definitions of Normalised and Comparator Valuations as used in the individual project reports are reiterated in Section 1.

Figure 1 – Overview of project developer estimated value, size and length of cables

Figure 2 – Overview of Comparator Valuation, size and length of cables

1. Background

The Offshore Transmission Owner (OFTO) licensing process requires a Regulatory Asset Value (RAV) to be determined for each of the transitional projects. One element of this valuation is to assess the efficient capital costs that are appropriate to include in the RAV. To these efficient capital costs, allowances for other costs, for example financing costs are added to form the complete RAV.

The cost assessment process undertaken by KEMA analyses cost information and reports submitted by developers regarding the extent to which the capital costs are reasonable and therefore could be judged as economic and efficient. The overall approach normalises information provided by developers, allocates costs consistently to the main components[3] of the offshore transmission system and also creates a set of disaggregated comparator cost drivers that can be used as peer benchmarks. Where necessary, developer cost information has been supplemented with comparator data from KEMA's repository of cost information[4].

KEMA has derived a normalised version of the developer's valuation, the "Normalised Valuation" and a benchmark valuation based on mean values derived from the transitional projects; this "Comparator Valuation" is described below:

- **Normalised Valuation**: uses the developer cost information and removes elements relating to contingencies, project financing and project purchases to provide a baseline figure relating to the actual (or forecast) costs associated with establishing the transmission assets. The Normalised Valuation is based upon submitted cost information incorporating contract cost data as provided by each project developer.

- **Comparator Valuation**: KEMA has derived the benchmark Comparator Valuation using a set of cost drivers, calculated from the information provided by the transitional projects. These cost drivers are mean unit cost values that are used to create cost benchmarks that can be compared with the Normalised Valuation. Where disaggregated cost data has not been provided, independent KEMA benchmark costs have been adopted.

KEMA regards the peer comparators as the most useful indicators of reasonable costs as these relate to projects being developed over a similar timeframe, in the same regulatory and legal framework, with comparable economic drivers and a similar supplier base.

This report provides an overview of the comparator metrics that have been used in the cost assessment process to derive KEMA's Comparator Valuations for individual projects. For completeness, an overview of KEMA's approach to independent benchmarking of electrical infrastructure costs is included in Appendix A.

3 The main components being the offshore substation, supply and installation of the submarine and land cables, onshore reactive power equipment and substation connection and development costs (capitalised operations costs, e.g. project management, overheads, leases and consents etc).

4 See Appendix A for more details

2. Overview of cost comparators

Individual cost comparators are used to create a Comparator Valuation for each project. These Comparator Valuations facilitate benchmarking to determine whether project costs can be regarded as reasonable. Seven (7) cost comparators have been derived for the purpose of assessing the reasonableness of developer offshore transmission asset costs. Not all of the comparator metrics described below have been used to derive the Comparator Valuation as some are insufficiently correlated between the projects for valuation purposes. The metrics are described below and those which have been used for deriving the Comparator Valuation are highlighted with an asterisk:

- Offshore substation cost per megawatt of secure capacity;
- Offshore substation electrical cost per megawatt of generation installed;
- Cable cost per kilometre supplied;
- Cost per Mega Volt Amp (MVA) for transformers;
- Capitalised development costs as a percentage of asset costs; and
- Cost of reactive power compensation per kilometre of cable.

2.1 Derivation of cost comparators

The cost comparators have been created by a process of normalising[5] and disaggregating (where possible) developer cost information in a consistent manner to the main components representing the majority[6] of the offshore transmission project costs as follows:

- Offshore substation, consisting of the platform, electrical items (switchgear and transformers) and installation costs;
- Cable supply (the entire length of both submarine and land cable supply as these are often part of the same contract);
- Onshore reactive power compensation equipment, consisting of the plant and equipment that provides the reactive power control for the wind farm to meet technical requirements; and
- Capitalised development costs consisting of capitalised developer operating costs included in each project (e.g. land owner easements, consultancy, engineering, supervision, allocated overheads but excluding any enduring maintenance provision)

5 The normalised project costs have been calculated by removing contingency, project purchase and financing costs where identified

6 Generally these cost account for 80% to 90% of the total costs

The comparator metrics have been derived by dividing allocated costs by relevant project parameters, e.g. kilometres in the case of cables.

Other cost elements that are more variable and therefore not suited to this high-level benchmarking approach have been added to the total according to the developer's estimation on the basis that no better information is available. These include the cable installation cost, platform costs and connection costs to the relevant distribution or transmission company.

The information received from developers in the Developer Information Request[7] has varied in the level of disaggregation and detail regarding capital costs. Where the cost information received has been at a more aggregated level further requests for information have been made in order to enable costs to be accurately allocated to the main components categories to derive peer benchmarks. It should be noted that the cost information relating [redacted] not been included in the comparator mean values because it was not regarded as sufficiently reliable. [redacted] provided did not align with the capital assets employed from the technical information provided and schedules did not summate correctly[redacted]

This report is based on information provided by developers up to and including 22 May 2009.

2.2 Overview of the main project characteristics

A summary of the key characteristics of each project is shown in Table 1, including those that are used in the derivation of the comparator metrics.

Table 1: Project characteristics[8]

Further insights regarding the relative size, position offshore and cost of the transitional projects is shown in Figure 3 and Figure 4. These charts plot each project according transmission capacity and cable length and demonstrate how costs vary according to increasing transmission capacity and cable length. The first chart plots the Normalised Valuations and the second chart plots the Comparator Valuations.

Figure 3 – Overview of project developer estimated value, size and length of cables

Figure 4 – Overview of Comparator Valuation, size and length of cables

7 The Developer Information Request was a set of questions and templates that each developer was required to complete to qualify for the transitional process for allocating Offshore Transmission Owner (OFTO) licences.

8 Discrepancies regarding total cable lengths are attributable to rounding approximations to the nearest km, [redacted]

3. Cost Comparators

A detailed description of each of the comparators and a commentary is provided below. A summary of the cost comparators is shown for reference in

Table 2: Summary of cost comparators[9]

3.1 Overview of project costs per megawatt of installed generator capacity multiplied by kilometres of cable

This high-level comparator metric provides an overview of the relative costs of the eight transitional projects as a function of the core characteristics. The comparator is formed by taking the total costs for each project and dividing by the product of the generation capacity installed (in MW) and the length (km) of cable connecting the offshore substation to the onshore substation (excluding turbine inter-array cables). Two cases are shown, the valuation as presented by the developer (the Normalised Valuation) and the valuation created from the individual cost drivers that are described within this report (the Comparator Valuation). [redacted] Figure 5 summarises variations in Cost/MW.km across each projects.

3.1.1 Commentary

Figure 5 shows that the Cost/MW.km for the [redacted] appears to be relatively high. [redacted] The relative costs of these projects suggest that there is not a linear function that relates the cost of the projects to the MW.km denominator. Either there are significant fixed cost elements in establishing the transmission assets or other influences impacting the costs of these projects.

Figure 5 does show a strong correlation between developer valuations and the overall Comparator Valuation based on the individual cost drivers described further in this report.

Figure 5 – Overview of total project cost per MW.km of generation installed

3.2 Offshore substation cost per megawatt of secure capacity

9 [redacted]

The cost of the offshore substation cost per megawatt of secure capacity has been used as a reference for the offshore substation element of the Comparator Valuation.

The offshore substation unit cost is created by dividing the costs identified by the megawatt of "secure capacity" that the substation delivers with an adjustment according to the number of platforms providing the capacity. The costs included are the platform structures, topsides and electrical equipment.

Secure capacity, has been defined as the power that can be exported with the loss of a single transformer. This denominator is used in preference to the total capacity or the MW of generation installed, because this minimises the effect of design choices (e.g. by providing more or less redundancy relative to the generation capacity etc) by simplifying the electrical infrastructure to the function of secure export capability. Figure 6 shows the variations in normalised offshore substation costs to per MW of secure capacity. The mean of all of the projects is indicated by the yellow line, labelled "Average".

Figure 6 – Offshore substation cost per MW secure

3.2.1 Commentary

[redacted]

[redacted] [redacted].

Compared to the Normalised Valuation, the measure consistently undervalues projects further than 15-20km offshore suggesting that other variable factors start to influence costs at such distances such as transportation costs which are heavily influenced by the distance offshore. Such projects are likely to incur more days operationally at sea which leads to increased costs per MW secure and also a greater likelihood of incurring weather delays that would further increase costs. In addition, the bespoke nature of platforms in this emergent field results in divergence of costs due to factors such as weight and overall dimensions.

Further analysis has been undertaken to segregate the electrical and structural cost components and seek additional refinements to provide greater consistency in the cost drivers.

3.3 Offshore substation electrical cost per megawatt of generation installed

The cost of the offshore substation electrical per megawatt of installed generation capacity has been used to provide further insights regarding the offshore substation electrical costs in the Comparator Valuation.

This Offshore substation unit cost is created by identifying the electrical costs of the offshore substation and dividing by the number of megawatts of installed generation capacity. The electrical costs, where not separately identified by the developer, have been subject to KEMA independent benchmarking to disaggregate the costs.

The cost of the offshore platform is included either as the developers estimate or from the derived cost based on KEMA's benchmark of the electrical assets that form the offshore substation. [redacted]

Figure 7 – Offshore substation electrical cost per MW generation installed

3.3.1 Commentary

Figure 7 shows strong correlation between the majority of projects, [redacted]. The costs submitted relating to [redacted] are considered unreliable and have been excluded from any of the mean peer comparators in this report. [redacted]

A lag in commodity prices would provide some explanation to the slight variation in prices, whereby the first group entered contracts for the electrical components between mid/late 2007 and early 2008 (likely with commodity prices at the mid 2007 level), whereas the second group entered contracts (or budgeted) at mid 2008 (with commodities priced at late 2007 early 2008) at the peak of the commodity prices. This could lead to lower outturn costs (assuming a commodity price adjustment clause is included in the contracts) for the latter group. [redacted]

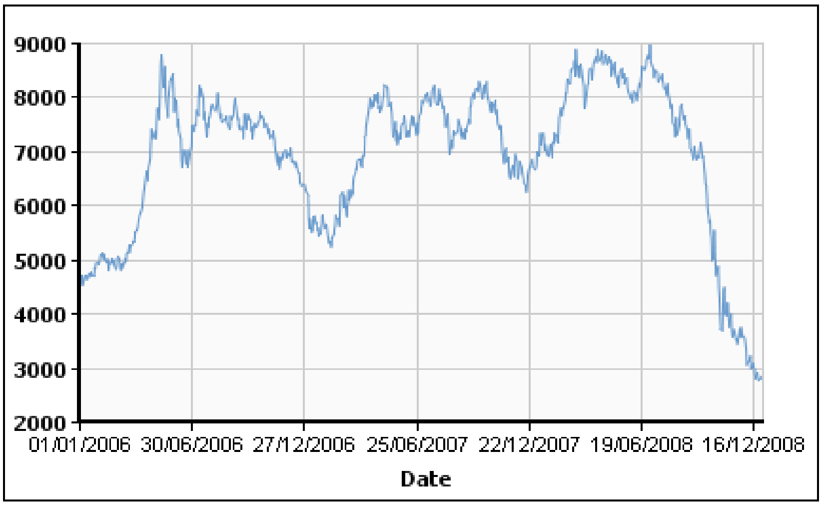

Figure 8 – Grade A Copper price $ per tonne 2006-2008 (source :London Metal Exchange)

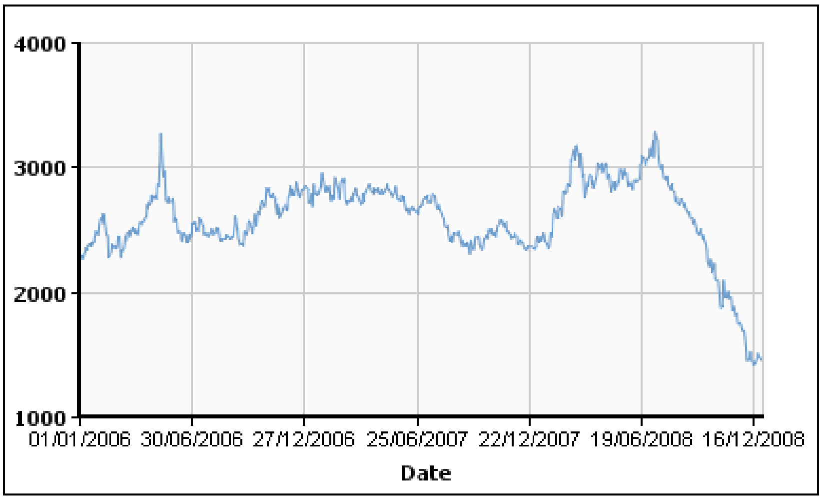

Figure 9 – Primary aluminium price $ per tonne 2006-2008 (source :London Metal Exchange)

3.4 Cable cost per kilometre supplied

The comparator for the cost per kilometre of cable supplied has been used to derive the main element for cable costs in Comparator Valuation. This comparator metric includes the costs to supply all cable, both on land and submarine, as these are frequently procured through a single supply contract. It also includes cable accessories (e.g. joints) but excludes any installation costs.

Unit costs for cables have been created by dividing the developers stated cost of the cable supply by the overall length (submarine and on land) in kilometres. Figure 10 shows the results, with the mean of all of the projects shown by the yellow line, labelled “Average”.

Figure 10 – Cable supply cost per kilometre

3.4.1 Commentary

The project developer costs for cables are reasonably consistent with little variation between the various supply costs. [redacted]

[redacted]

3.5 Cost per Mega Volt Amp (MVA) for transformers

Unit costs for transformers have been made comparable by dividing the total cost of the transformers procured or specified by the rated capacity of each transformer measured in megavolt amps. Figure 11 shows the results, with the mean average of all of the projects shown by the yellow line, labelled “Average”.

Figure 11 – Transformer costs per MVA installed

3.5.1 Commentary

Figure 11 demonstrates that the transformer unit costs per MVA are consistent between the projects, within a narrow +/-5% range and are considered reasonable when compared to benchmark costs. [redacted]. The costs for this project are generally considered unreliable and of an indicative budgetary nature. The extent of cost variations for the remaining projects [redacted] is not regarded as significant.

3.6 Capitalised development costs as a percentage of asset costs

The capitalised development costs include all costs that are not capital assets. Typically this will include the costs for project management, design, consultancy, environmental studies, acquiring consents and other non-capital asset costs that relate to the establishment of the transmission system. Any enduring maintenance related expenditure has not been included within development costs.

This measure forms a cost comparator that provides insights regarding the relative magnitude of capitalised development costs and an input to the Comparator Valuation. The adjusted development cost added to the Comparator Valuation is created using the mean net percentage figure i.e. excluding the development costs from the total cost.

$$\text{Capitalised development cost \%} = 100\% \times \frac{\text{Capitalised development cost}}{\text{Total Normalised Valuation} - \text{Capitalised development costs}}$$

For presentation purposes the results are presented as a percentage of the total Normalised Valuation or percentage of the Comparator Valuation.

Figure 12 – Development costs as a percentage of the normalised project cost

3.6.1 Commentary

Figure 12 shows that capitalised development costs as a percentage of the valuation are reasonable consistent between projects. The majority of the projects lie within a band of +/- 3% of the project cost. [redacted]

[redacted]

A high-level analysis of the information submitted by developers (where suitably disaggregated) has allowed a high-level estimation of the various costs that contribute to the capitalised development costs. This information excludes all single contract projects, which may be expected to incur slightly higher costs depending on risk allocation. The result of the analysis is shown below:

TASK	
Project management, supervision and general consultancy	5-6%
Design and engineering costs	1%
Allocated overhead costs	2-4%
Environmental assessment and consultancy	1-2%
Consents acquistion	1-2%
TOTAL	10-15%

3.7 Cost of reactive power compensation per kilometre of cable

The cost of reactive power compensation equipment per kilometre of cable (total of land and submarine) in the majority of cases assesses the costs incurred by developers to manage the reactive power characteristics of the cable. It generally ignores design choices regarding generator capabilities and system requirements in relation to provision of reactive power and voltage control at the onshore and offshore points of connection.

Figure 13 – Cost of reactive power substation per kilometre of cable (land and submarine)

3.7.1 Commentary

Figure 13 shows the cost of reactive power compensation equipment per kilometre of cable. The costs vary between projects due to differences in design philosophy of the reactive equipment. In the majority of the projects considered here, the requirement for reactive power compensation equipment for an offshore transmission system largely relates to the inherent capacitive nature of cables. The impact of this capacitance is to cause voltage rise at the offshore and onshore connection points and must be corrected by the application of reactors. In addition, some developers have specified greater reactive power control, provision and flexibility and have thus incorporated more sophisticated compensation equipment and harmonic filters within their designs to assist respective generators to meet industry code requirements, thereby creating a different cost profile.

4. Comparator Valuation

This section provides a summary of the disaggregated cost comparator valuations for each of the projects as utilised in the total Comparator Valuation. The figures show how closely the disaggregated (normalised) developer valuations align with the comparators and any significant variances are highlighted. In the case of offshore substation costs, alternative measures are provided to reinforce that the Comparator Valuations derived are robust and represent a reasonable benchmark against which the developer's estimates may be assessed. In this section, absolute values for the disaggregated cost components are provided rather than percentages and unit costs

4.1 Offshore substation valuations

The electrical equipment component of the offshore substation is regarded as a robust peer comparator as the costs of standardised electrical infrastructure is well understood and is therefore used as a cost input for the Comparator Valuation. The total offshore substation valuation is therefore created using a composite of the offshore substation electrical equipment and a cost for the offshore platform. The platform costs included in the Comparator Valuation are either those submitted by the developer or a KEMA derived cost, calculated by removing electrical costs (based on international benchmarks) from the developer's valuation of the entire offshore substation.

Additional validation of the derived substation valuations have been undertaken based upon two methods. The first method is based upon peer comparison to derive an average cost of the offshore substation per secure MW, i.e. transmission capacity with one transformer out of service. The second method as a dual parameter based assessment that seeks to capture both secure transmission capacity and the distance offshore. The distance offshore was incorporated due to unexplained variations becoming apparent in the results of the MW secure comparator alone. Together these reinforce confidence that the Comparator Valuation provides a reasonable benchmark from which the Normalised Valuations can be assessed.

Figure 14 – Valuations for the Offshore Substation

4.2 Submarine and land cable supply and installation

Supply and installation costs for submarine and land cables have been used to produce a composite comparator metric. The cable elements included in the Comparator Valuation have been derived from the cable supply cost per kilometre, added to the developer view on the installation costs.

Figure 15 – Submarine and land cable supply and installation valuations

Onshore and offshore cable installation costs were excluded from the cost driver due to the considerable variations apparent. Land based installation costs are highly variable depending on the techniques adopted, e.g. horizontal directional drilling can increase costs substantially. Similar variations apply offshore, with seabed conditions driving different cost profiles. This is illustrated in Figure 16 below.

Figure 16 – Submarine supply and installation cost variability

Cable supply costs typically represent more than half the total installed cable cost and therefore provide a satisfactory benchmark alongside which the developers' own estimates for installation are added. [redacted]

4.3 Reactive power compensation equipment valuation

The reactive power compensation equipment element of the Comparator Valuation is derived using the mean reactive power compensation per kilometre of installed cable (submarine and land) cost parameter. The reactive power compensation equipment element of the Comparator Valuations varies substantially from developer estimates of cost with the most significant divergences [redacted]

In absolute terms, the costs of reactive power compensation equipment [redacted]. However, the discrepancy between the Normalised and Comparator Valuations for [redacted] reactive power compensation equipment merits further investigation.

Figure 17 – Reactive power compensation equipment valuations

4.4 Capitalised Development costs

The capitalised development cost element of the Comparator Valuation is driven by the mean development cost percentage metric calculated net of the capitalised development cost as described in Section 3.6.1.

[redacted]

Figure 18 – Capitalised development valuations

Appendix A - KEMA's Approach to Unit Cost Benchmarking

Introduction

KEMA has significant experience and a proven track record concerning cost engineering and the valuation of assets for electrical utilities. Teams of senior staff have calculated project costs for new substations, high-voltage lines and cable systems around the world and assessed the value of the assets of many utility companies internationally.

The Unit Cost Database

Since it was founded in 1927, KEMA has carried out technical consultancy and business projects in Europe, North and South America, Australia and Asia. In 1998, KEMA started collating the information gathered from these projects into a cost database to allow comparisons to be made. The database entries derived are from:

- Calculations for major projects for low, medium and high voltage electricity infrastructure in various countries all over the world; and
- Equipment offers and proposals of manufacturers for all relevant civil, mechanical and electro technical components in high voltage transmission lines, substations (indoor / outdoor, air insulated / gas insulated) and cable connections.

Data validation and handling

Each time new information is added it is checked for consistency. This process takes the new information, tests it against the current best view of costs for the particular item. Where this deviates outside of the recognised bandwidth for that item, the cost will be reviewed in detail to understand whether there are reasons to justify a step change in the cost of this item, or whether there are particular circumstances that justify the differential in the cost. The volume of data that has been collated allows a prediction of a reasonable spread of costs that is derived over time for individual equipment and related engineering and civil works. This together with experience led analysis results in a mean value for the unit costs that is appropriately weighted to reflect market conditions and an understanding of the likely divergence bandwidth for unit costs.

Combined together KEMA's engineering expertise and the data collected enables estimation of costs in two dimensions:

- <u>Interpolation within the data</u> for variances in technical specifications, e.g. from the cost information for 100 MVA transformers and 50 MVA transformers, both of the same type and voltage, it is possible, with the necessary experience, knowledge and data to accurately calculate the cost of a 60, 75 and 80 MVA transformer.
- <u>Extrapolation over time</u>. Trends can be observed in the price development of equipment, e.g. if the price of certain type of reactor coil is known for multiple years, than this information can be combined with inflation figures, exchange rates and raw material prices to calculate the estimated cost in the (near) future. The database has sufficient source data that enables the observation of negative price trends, e.g. for SF6 installation.

Benchmarking

The use of the database in benchmarking therefore results in a very accurate calculation for the cost of each project, because regardless of the actual specification of equipment used, the database is likely to have a reference that is either directly comparable or easy interpolate to the item. These act as straightforward benchmarks, given the international nature of the market for electrical equipment that can then be adjusted for local factors (see below).

These calculations by KEMA have often been used during the decision-making process and the discussions of the utility management and the project developers.

Geographical coverage

The database is populated via international projects and manufacturers responses. The geographical origin of the data is also stored in the database and is considered as part of the consistency checks when the data is accepted.

Geographical differences most often centre on the costs for civil work and engineering, which are inflated or deflated depending on the country of the project. Furthermore, each country has different factors to be taken in consideration, e.g. tunnelling in rock, earth or clay will result in different costs. Also regional aspects such as rural versus urban (higher costs for cable laying, way leave, etc) are taken in consideration.