The application of benchmarking in the assessment of distribution businesses investment plans and the associated network information requirements

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INTRODUCTION

This paper attempts to bring together a number of issues relevant to the determination of efficient levels of capital investment in electrical distribution businesses. It draws upon modelling techniques employed in the United Kingdom, Australia and Argentina, and also upon information available to distribution network operators and to energy industry regulators in those locations. Whilst the techniques may be applied in other jurisdictions, one of the key determinants to the usefulness of such techniques is access to the necessary network information.

The paper firstly replays the benchmarking applied during the 1999 review of the GB distribution businesses and gives an indication of the higher level approach that could be adopted by an energy regulator when presented with comparable information from a number of differing distribution businesses.

The paper then goes on to give an indication of the investment decisions that may be taken internal to a distribution business, based upon the available network information.

BACKGROUND

As national governments strive to reduce demands on their expenditure, there is a world-wide trend to move electricity businesses, and other utilities, from state to private ownership. At the same time there is a drive to reduce costs to customers, to enhance quality of service, as well as to seek to fund investment in this essential service area.

Transmission and distribution businesses are generally considered to be natural monopolies, as it is not economic for several companies to compete in the same geographic area. Under such conditions there is a possibility of abuse of monopoly power and, without competition, there may be little incentive for companies to reduce costs or improve efficiency. As a consequence it is necessary for such companies to be subject to some control of the charges made to customers.

In the United Kingdom and in a number of other countries, 'price cap' regulation is applied allowing incentives for the companies to retain efficiency savings. The ‘Price Controls’ generally take the form of an assessment of required income with a continuing requirement for efficiency gains that act as a proxy for competition.

GB REGULATORY REVIEW PROCESS

In GB, regulatory reviews of distribution price controls are carried out at intervals of 5 years. The third distribution price control conducted by the GB energy regulator, Ofgem, covered changes to the charges for use-of-system and (to a limited extent) connections. The distribution price control was based upon an analysis of the historic and forecast business operating and capital expenditure requirements and assessed efficiency gains.

The distribution charges are permitted to vary each year according to the formula RPI - X, where RPI is the retail prices index (inflation index) and X is an efficiency factor. To date, this form of price control has led to significant price reductions as well as quality improvements for customers. It is this type of control which was subject to consultation in December 2003 by the National Electricity Regulator in South Africa and is the proposed basis for Incentive Based Regulation of both Transmission and Distribution.

Under the GB distribution price control review, Ofgem reviewed the forecast expenditures of the 14 distribution companies in Great Britain, covering the years 2000/01 to 2004/05[1]. In this paper we describe the techniques that were used in the review of the capital expenditure forecasts submitted by each of the companies. Similar periodic price control reviews are proposed for South Africa, with a proposed 3 year control period initially, to minimise the risk to all stakeholders, prior to settling on a longer, 5 year control period which allows greater scope for efficiency gains by operators with resultant benefits for all.

GB COMPANY ANALYSIS

Each company was required to submit its capital investment plans in response to an extensive questionnaire. The questionnaire responses indicated forecast investment programmes totalling more than US $10 billion over the 5-year period. As there are 14 distribution companies in Great Britain, there was a good opportunity for benchmarking costs and performance, even for networks as diverse as the high density largely underground cable network of London Electricity and the rural, weather affected, and largely overhead network of Scottish Hydro-Electric.

On distribution networks, capital expenditure is generally classified as follows:

- **Load-related expenditure**, which provides new connections and reinforcements to meet load growth
- **Non-load-related expenditure**, which includes asset replacement, environmental and safety requirements, and system control
- **Quality of supply expenditure**, which results in improvement of reliability, power quality and customer service.

In practice an element of asset replacement may be incorporated in network reinforcements driven by demand growth, and conversely replacement of older assets may well deliver improvements in quality of supply and also additional network capacity if assets are not replaced on like-for-like basis. However, when taken overall the classification of expenditure into the three categories identified above is generally relatively consistent between companies, partly due to the discipline and common practices imposed on such companies prior to privatisation.

In the case of South Africa where distribution network operators may be historically quite different, a certain degree of regulatory guidance may be necessary to ensure that such information is provided in a consistent way.

Initial review. An initial review was made of the underlying drivers such as increasing customer numbers, increased demand, load movements from one area to another and also the need to replace ageing and poor performing equipment. This indicated significant differences between normalised expenditure forecasts of the various companies.

These variances were attributed in part to specific company efficiency savings and also to factors outside the companies' control, especially differing levels of growth in customer numbers and demand. The deployment of new IT systems to record and analyse better the condition of network assets and hence replacement expenditure was identified as an important factor in the reduced expenditure forecasts of some of the companies.

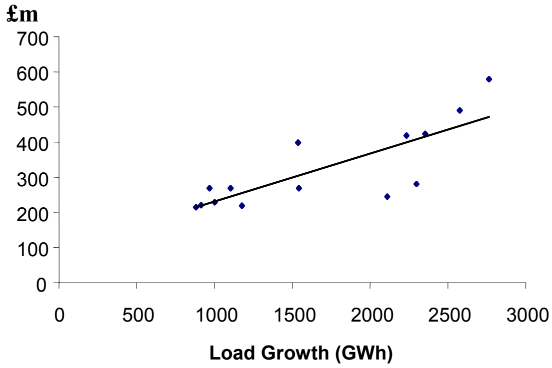
BENCHMARKING OF CAPITAL EXPENDITURE

Load-Related Expenditure

Influence of load movement. The growth in power demand in Great Britain is low with average annual long-term growth in peak power and energy demands being only 0.6 per cent and 1.2 per cent respectively. A model of marginal cost of distribution network development per additional kW of demand was therefore not considered to be appropriate to review load-related expenditure in this instance. Furthermore from the outset, the sheer size and scale of the networks concerned precluded detailed modelling.

Initial modelling of cumulative development cost per additional GWh of distributed energy showed that load movement (churn) rather than load growth was a relevant driver. The trend line on Figure 1 shows clearly that there is an appreciable element of expenditure that is independent of load growth.

Fig 1. Cumulative Load Related Expenditure v Load Growth (6 years)



New customers as investment driver. After further analysis of historic and forecast expenditure, the relationship between historic expenditure and numbers of new customers was found to be a more stable indicator than distributed energy. This relationship was shown to provide the closest correlation of the models analysed and was applied to set the allowed load related expenditure.

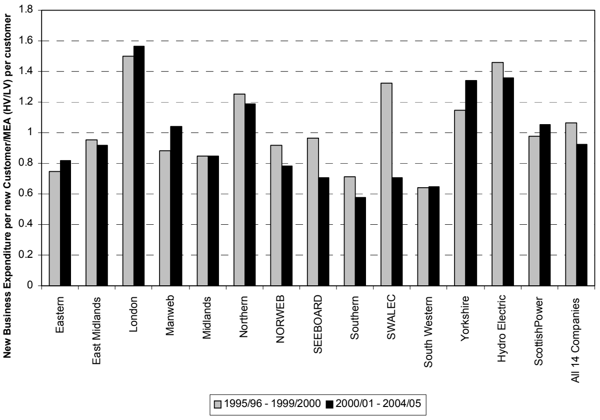
Due to the differing natures of the company electrical networks, the expenditure was normalised by comparing the ratios of:

- overall expenditure per new customer with modern equivalent asset (MEA) value per customer and
- new business expenditure per new customer with the MEA value of the medium and low voltage assets per customer.

In so doing it was possible to differentiate between new business (connection) expenditure and the (more deep-seated) reinforcement expenditure. The MEA values were obtained by multiplying the quantities of relevant assets, as declared by the companies, with the corresponding company specific unit costs. The use of MEA/customer is considered to be an appropriate way of characterising the specific nature of the network to which the customer is connected, whether it be a high density urban area or low density rural, providing of course that new customer connections are themselves consistent with the existing customer distribution.

Fig 2 shows expenditure per customer as a proportion of the per customer MEA value for the three price control periods from 1990/91 to 2004/05. An average value of between 0.8 and unity is indicated for all 14 companies, reflecting companies' overall efficiencies and expectations to drive costs down. Without such savings it would otherwise be expected that on a long-term basis this value would be unity.

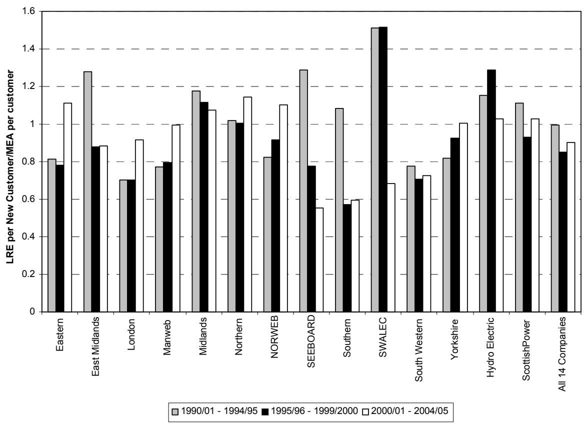
Fig 2. Normalised Load-related expenditure by Price Control Period



Viewing expenditure on a longer-term basis also allows for the uneven nature of more deep seated reinforcement expenditure with time. The use of MEA values also implicitly takes into account the historic level of under-utilised assets and hence "churned load" in a company's system.

Fig 3 shows the normalised new business expenditure by price control period and indicates a similar level of correlation to that in Fig 3. In practice a median rather than an average MEA value per customer was used, so that extremes would not affect the adopted benchmarking position.

Fig 3. Normalised new business expenditure by Price Control Period



A view was then taken on the companies' projections of numbers of new customers, comparing these with historic trends of both customer numbers and energy consumption. The revised forecasts of new customers and the MEA value per customer were then applied to derive a projected expenditure. It should be noted that this exercise highlighted some significant, but illusionary changes in customer numbers which had arisen due to Ofgem initiatives with respect to improving the accuracy of customer records and connectivity.

As a result of the load-related benchmarking process, Ofgem projected a total load-related expenditure of US $3.8 billion, significantly lower than the aggregate of the companies' forecast of US $4.3 billion (i.e. the allowed expenditure was about 88 per cent of that forecast by the companies).

Non-load Related Expenditure

Asset replacement modelling. Asset replacement is the principal component of non-load related expenditure, other components including expenditure in respect of safety, environment, diversions and network management.

The basic process of long-term modelling of asset replacement funding requirements is centred upon the cross multiplication for each asset category of the asset quantity of a given age with the assumed replacement rate for that age of asset. The output represents the volume of that asset to be replaced. This asset replacement volume is then multiplied by the appropriate unit replacement cost to give the estimated replacement expenditure for that asset category[2].

The dominant asset categories are transformers, switchgear (including substation civil works), overhead lines, underground cables and service connections to customers, including meters.

Benchmarking of expenditure. The expenditure forecast of each distribution company was reviewed using the following data provided by each company:

- asset age profile data for each asset category (about 40 individual asset categories were analysed)
- asset replacement profiles (percentage of a given asset population replaced in a given year) and
- unit replacement costs.

In addition an independent database of unit costs was also established based upon other known project related costs and estimated equipment installed costs based upon supplier budget cost information.

From the data provided by the companies, average weighted replacement profiles were established for each specific asset category. These showed average lives slightly longer, if anything, than those estimated and employed by Ofgem at the previous price control review in 1994. The review of each company's expenditure was however based on its own asset age profile data.

Firstly, an 'asset replacement benchmark' factor for replacement quantities of each asset category by comparing

- a projection of expenditure based on the weighted replacement profiles and the companies' unit costs for each asset category with the
- corresponding expenditure forecast by the company.

By comparing the ratios of the expenditures for each asset category by company, median asset replacement benchmarks for quantities were obtained.

A similar comparison of replacement costs was then made between the expenditures derived from modelling using the companies' unit costs and our own unit cost database respectively. From the resulting ratios a median 'cost-indexing factor' was obtained. In so doing expenditure projections were normalised onto a common company-wide cost base which was not heavily influenced by our own cost database.

The asset replacement benchmarks and cost-indexing factors for each asset category were then applied to the respective expenditures projected by the model in order to provide a corresponding projection of non-load related expenditure. A flow chart presentation of this "benchmarking" process is presented in Figure 4

After due consultation with the companies and allowances made for expenditure to replace certain cable and switchgear types with particularly poor performance or safety records, Ofgem projected non-load related expenditure of US$5.0 billion against US6.4 billion forecast by the companies.

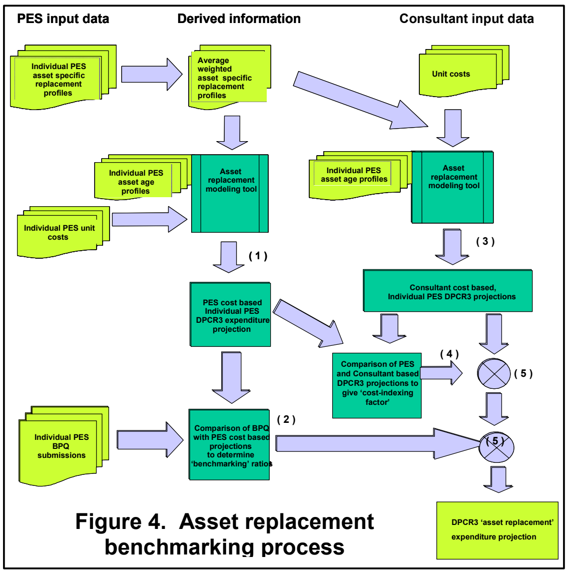
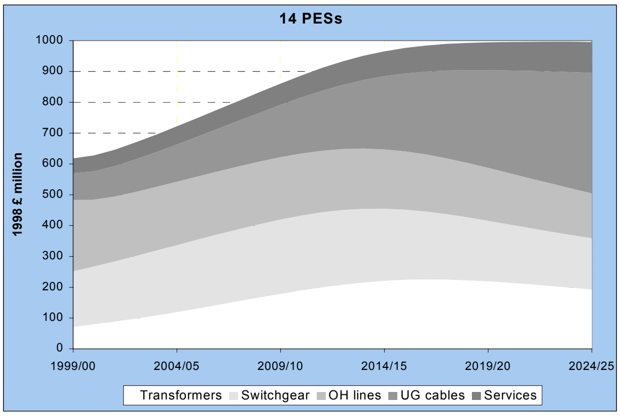


Figure 4. Asset replacement benchmarking process

Due to concerns that the significant reduction in allowed expenditure could result in a delayed "bow-wave" of expenditure, the benchmarking model was employed to produce a long-term projection of overall replacement expenditure which is shown in Fig 5. This indicates a slowly rising trend influenced particularly by increasing replacement of transformers and underground cables.

Fig 5. Long-term trend for Non-load related expenditure



QUALITY OF SUPPLY EXPENDITURE

This expenditure is focussed on retaining or improving existing levels of 'quality of supply' (QoS), essentially the numbers and durations of supply interruptions. For the purposes of the price control review, the companies were required to declare separate investment proposals for a:

- 'Base Case' being only those investments necessary to maintain the network in its current functional condition and

- 'Quality Measures Case' combining the Base Case and specified investments for improvements to quality of supply, together with the corresponding targets for the improved performance.

In the case of the DPCR3 review, rather than benchmarking company QoS proposals, a comparison of the costs and benefits of the companies' existing and future quality measure programmes to improve supply interruption performance was undertaken. The benefits were calculated in economic terms using the concept of System Customer Outage Costs (SCOC)[3], and hence provided an indication of the extent to which the programmes could be considered to be cost-justified on an absolute, rather than comparative basis.

REGULATORY BENCHMARKING OVERVIEW.

The work described above was essentially undertaken to assist the GB energy regulator in setting price controls for a total of 14 distribution companies. To a large extent the high level approach adopted was the result of an asymmetry of information between the regulator and the regulated businesses, with the regulator being generally considered to be the disadvantaged party.

Due to the competitive nature of independently owned distribution businesses there is often only a limited level of collaboration between individual distribution businesses. This level of secrecy arises from a degree of insecurity within such businesses when faced with potential hostile takeovers from companies which may consider themselves to be potentially better asset managers than the sitting tenants and hence able to obtain a better return on capital.

In such situations it is possible for the regulator to reduce the information asymmetry by requesting comparable information from all the businesses in his area of control, and undertaking benchmarking as discussed above. By this means, the regulator can establish an approach in which the individual businesses are essentially acting to regulate each other in areas of capital and also operational expenditure.

In such situations however, the regulator may be under-funding the industry and hence placing it at risk if he does not have access to adequate information about the industry that he is regulating. The risk of under-funding arises if one or more of the regulated businesses is itself seriously under-spending due to financial weaknesses and hence delaying necessary new investment. Such a business could be seen as being super efficient, and through the use of benchmarking depriving its peers of a correct level of funding. In order to minimise distortions of this type, benchmarking was undertaken on a percentile rather than average basis,

One of the ways of avoiding such a situation is by requiring companies to establish and maintain adequate network databases and to audit such databases on a regular basis. In the case of capital investment management such data bases need to include a register of all key assets, including details of their age and condition, fault rates and repair and maintenance expenditure. Other information that is needed relates to the actual life expiry information on such assets such that reliable forecasts of replacement capital expenditure can be developed, both in the shorter and also the longer term horizons.

With access to reliable information of this nature, the energy regulator will be in a position to accurately monitor the health of the network and hence avoid risks to customers supplies whilst at the same time avoiding unnecessary investment.

One of the output measures favoured by energy regulators is quality of supply, essentially continuity of supply to customers. However, as was the case with the GB rail network, measures such as network availability can be maintained and/or improved against historic levels by delaying maintenance and other essential works. However such an approach can result in significant disruption at later times.

In the case of electrical networks with a certain degree of component redundancy, continuity of supply may be only marginally affected by increasing fault rates. However such fault rates may be the signal for a level of asset replacement. Where increasing fault rates are an indication of approaching end of life it is important that such information is not lost through averaging such fault rates across the whole asset population. In a similar way, increasing operational and maintenance costs should also be related to asset age.

In the case of the development of the South African distribution networks, and the possible aggregation of historically separately managed businesses it is equally important that the information currently available on the separate parts is not diluted when a larger operating unit is established. Information of the type identified above is clearly important to both the network operators and also the regulator. Examples of where such information can be put to good use to minimise overall network costs and/or improve quality of supply are presented below with respect to distribution networks in Australia and also in Argentina.

CAPEX-OPEX TRADE OFF.

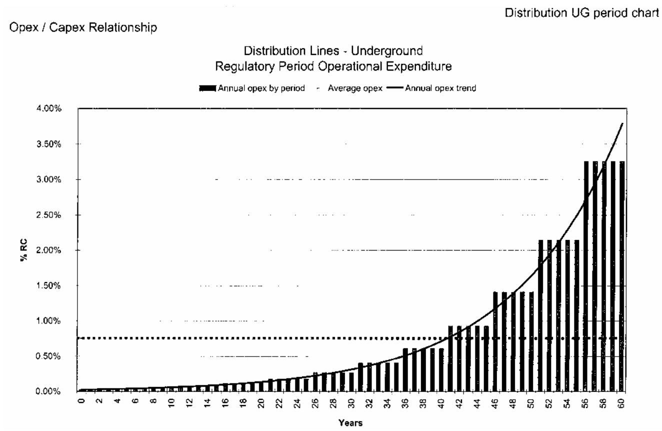
Distribution networks assets include substations, transformers, overhead lines, cables, and other equipment, from LV to Sub-Transmission voltages. All these assets require some level of maintenance throughout their life and the total O&M expenditure on assets can be considerable. For a network with average asset age of about 30 years, this is typically equivalent to about 3 percent per year of the MEA value. From a revenue point of view the O&M costs are equivalent to about 1/3rd of the allowance for depreciation and return on assets.

The level of maintenance of an asset varies with the age of the asset. The longer an asset is in service the greater will be the associated repair and maintenance costs, thus any capital expenditure which reduce the age of assets will also reduce the maintenance requirements. These savings are however offset by the addition of new assets to the asset base requiring additional maintenance expenditure, albeit less than that for the assets replaced.

There exists therefore a relationship between capital investment and maintenance expenditures. The extent to which the relationship can be determined is a function of the information available to the system operator. In the case of modelling that has been undertaken in Australia the relationship has been assumed to increase exponentially with age, which is generally consistent with equipment failure rates as they approach end of life, refer to Figure 6 below.

The key parameters of the model and very often the only information readily available is the average and the initial expected Operating and Maintenance expenditure expressed in terms of the replacement value of that asset category.

Figure 6 – Opex~age relationship.



In the case of the referenced study, the asset base was divided into 10 asset categories. For each of these categories an average O&M spend as a percentage of the Replacement Cost of the assets was calculated as well as an initial expected O&M cost. The expenditure in each category is due to planned, corrective, and emergency (storm) maintenance, the initial expected O&M expenditure was taken to be planned maintenance cost only and as emergency (storm) maintenance is not affected by refurbishment investments it was excluded from all calculations. Typical parameters are presented in Table 1 below

The major projects and programs capital expenditure for new assets and refurbishment were evaluated with regard to the expected Operating Expenditure/Savings. The findings of this analysis was a saving of about $10 million over the 5 year regulatory periods. This saving equates to 0.8% of the capital investment in the period and hence when expressed in terms of associated revenue allowances represents a saving of about 10 percent.

Table 1.

Asset Class Description	Regulatory Asset Life	MEA Replacement Cost ($M)	O & M Expenditure ($M)	Average O&M (ex. O/Heads) (% RC)	% Overheads allocation	Total Average O&M (incl. O/Heads) (% RC)	% Average Planned O&M Expenditure p.a.	Initial O&M Expenditure p.a. (% RC)
Distribution Substations	40	$1,060.43	$9.31	0.88%	35.00%	1.18%	30.00%	0.36%
Sub-transmission Substation Circuit Breakers	45	$183.64	$2.51	1.37%	35.00%	1.85%	50.50%	0.93%
Zone Substation Circuit Breakers	45	$428.48	$1.81	0.42%	35.00%	0.57%	45.40%	0.26%
Sub-transmission Substation Transformers & Tap Changers	50	$101.85	$1.13	1.11%	35.00%	1.50%	54.00%	0.81%
Zone Substation Transformers & Tap Changers	50	$233.01	$3.79	1.63%	35.00%	2.20%	47.00%	1.03%
Sub-transmission & Zone Substation Protection & Control	45	$1,024.67	$2.96	0.29%	35.00%	0.39%	62.30%	0.24%
Transmission Lines - Overhead	55	$379.48	$2.10	0.55%	35.00%	0.75%	36.40%	0.27%
Transmission Lines - Underground	45	$1,596.58	$4.83	0.30%	35.00%	0.41%	3.70%	0.02%
Distribution Lines - Overhead	55	$1,072.03	$35.71	3.33%	35.00%	4.50%	17.80%	0.80%
Distribution Lines - Underground	60	$1,635.30	$9.35	0.57%	35.00%	0.77%	3.30%	0.03%

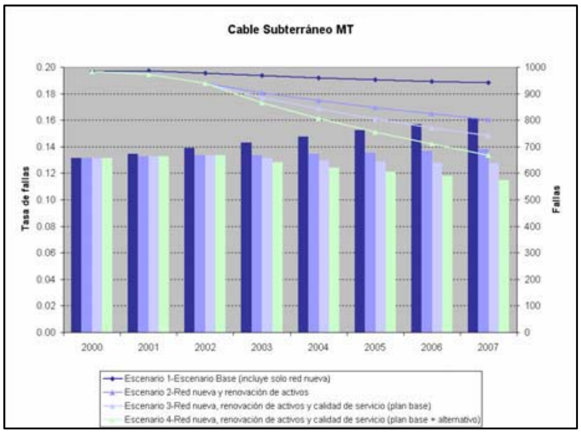
Clearly this sort of analysis is very dependent upon the quality of the data input however it is evident that such savings may be appreciable when expressed in terms of allowed revenue and may weigh significantly when comparing alternative network investment. It is therefore important that the relevant information is collected and collated whenever possible.

QoS - ASSET REPLACEMENT TRADEOFF

An example of the possible network quality of supply benefits which may be achieved by judicious asset replacement expenditure was investigated during the course of tariff review work undertaken in Argentina. In the case of the distribution company involved, excellent network information systems were available and hence it was possible to investigate the impact of targeted investment on QoS.

In Figure 7 below a total of four underground cable replacement scenarios were investigated against a background of continuing network development. As a consequence it can be seen from the Base Case (Escenario 1) that the addition of new underground cables associated with the demand growth and the connection of new customers results in a fall in the overall fault rate.

Figure 7 – Fault rate ~ asset replacement.



However, if the effects of the new network plus end of life replacement of the older cable assets takes place (Escenario 2) a 25 percent fall in fault rate occurs. Other scenarios are also presented with varying degrees of return. If it is recognised that in Argentina significant penalties are imposed on poorly performing distribution companies, then it is clearly important for the company to be in a position to undertake such analysis in a robust way such that it can influence the regulator with respect to the appropriateness or otherwise of such penalties, or conversely to determine for its own internal purposes the consequence of certain courses of action. The importance of retaining and enhancing network information with respect to issues such as age related equipment fault rates is clearly evident.

SUMMARY.

It is evident from the work presented above that knowledge of the distribution network is one of the most important issues associated with the management and development of the network. Similarly such knowledge is also important to the efficient regulation of the network and as a safeguard against serious degradation of supply quality with associated adverse impact on customer comfort and safety and also economic development.

The extent to which such network information is disaggregated is also important and, at times of rapidly changing network structure and organisation it is important that historic data is not lost or aggregated into a form that prevents its full usage.

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[1] Ofgem, December 1999, "Review of Public Electricity Suppliers 1998 to 2000, Distribution Price Control Review, Final Proposals".

[2] Douglas JAK and Morris CH, "retirements Modelling for the Long-Term Planning of the Replacement of Distribution Assets", CIRED'99 Report 6/10

[3] Kariuki K K, Allan R N, Palin A, Hartwright B, Caley J, "Assessment of Customer Outage Costs due to Electricity Service Interruptions", CIRED'95 Report 2.05.1

About the presenter: David Bailey has over 30 years of experience in the design and analysis of electrical power networks and has worked in most parts of the world.

His career began at A. Reyrolle and Co, the switchgear manufacture in Hebburn, Co Durham, England from where he moved in 1970 to join Merz and McLellan in Newcastle upon Tyne. From his first days at Merz and McLellan he has been involved in EHV and HV projects throughout the world, becoming both an Associate and also the firms Chief Power Systems Design Engineer, then a Vice President and Senior Professional Associate of PB Power.

Since 1989 he has been heavily involved in Electricity Industry restructuring and has provided advice to the UK and overseas governments, energy regulators and transmission and distribution businesses.

In January 2004 he joined Sinclair Knight Merz as a Senior Consultant, Strategic Consultancy in their newly established Newcastle upon Tyne office, and in doing so re-established his links with the Australian and South African descendent companies of Merz and McLellan.