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SHEPD

DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS

OCTOBER 2004

LIST OF REVISIONS

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Final	18/06/04	All	Adjustment following submission of final capital expenditure numbers.			
Final	22/10/04	All	Revision of model and allowance levels following DNO meetings with Ofgem and Ofgem September paper.			

CONTENTS

Page No.

LIST OF ABBREVIATIONS

ACS	Average Cold Spell
Capex	Capital expenditure
CHL	Customer hours lost
CI	Customer interruptions per 100 customers
CML	Customer minutes lost per connected customer
Consac	A type of concentric LV mains cable
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review
DTI	Department of Trade and Industry
EATS	Electricity Association Technical Specification
EHV	Extra High Voltage (i.e. > 22kV)
ESQCR	Electricity Safety, Quality and Continuity Regulations 2002
FBPQ	Forecast Business Plan Questionnaire
GDP	Gross Domestic Product
GVA	Gross Value Added
GWh	Gigawatthour (a unit of energy)
HBPQ	Historic Business Plan Questionnaire
HV	High Voltage (i.e. between 1kV and 22kV)
km	kilometre
kV	kilovolt
LV	Low voltage (i.e. less than 1kV and here 230/400V)
m	Million
MEAV	Modern Equivalent Asset Value
MPAN	Meter Point Administration Number
MPRS	Meter Point Registration System
MW	Megawatt (a unit of power)
NGC	National Grid Company
NUTS	Nomenclature 0f Units for Territorial Statistics
OHL	Overhead line
PB	Parsons Brinckerhoff
QoS	Quality of supply (reliability/interruption performance)
SEPD	Southern Electric Power Distribution plc
SHEPD	Scottish Hydro-Electric Power Distribution plc
SSAP	Standard accountancy practice
SSE	Scottish and Southern Energy plc

EXECUTIVE SUMMARY

This report sets out the views of PB Power on the capital expenditure in the DNO's FBPQ submission to Ofgem for DPCR4. It supersedes the earlier (June 2004) report and changes reflect the outcome of the meeting with the DNO in August 2004.

The comments in the report are based on the information provided by the DNO concerned as part of the FBPQ submission to Ofgem, subsequent meetings and information exchanges between Ofgem, ourselves and all the DNOs. The volume of information submitted in support of the business plans has been substantial in both narrative and numerical form and, together with subsequent meetings and clarifications, has provided an insight to the rational for expenditure variation compared to that in DPCR3.

We have however reviewed the expenditure and drivers of the DPCR4 Base Case Scenario only, with a limited overview of the Ofgem Scenario/Sensitivity and the DNO Alternative Case. In particular, we have taken note that Ofgem's requirement that capital expenditure included in the Base Case Scenario should be only that necessary to maintain the distribution system at its existing performance level in respect of quality of supply. It follows in our view that the level of network risk experienced during DPCR3 should also be held constant during the forthcoming review period. Where DNOs have included expenditure that may not fit with those objectives then such expenditure is not deemed to be appropriate to the Base Case Scenario and has therefore been excluded from our considerations, except as part of the process of identifying such expenditure. This approach does not imply that we do not believe that the non-Base Case expenditure identified is inappropriate or unjustified; in fact in some instances we have observed that non-Base Case expenditure may be prudent. This approach of limiting consideration to only the Base Case Scenario seeks to ensure that all DNOs are considered on an equitable basis with any further consideration as to treatment of special cases resting between Ofgem and the DNO concerned.

Our approach to the modelling of both load-related and non-load related expenditure has been developed on principles agreed by Ofgem and discussed with the DNOs. The models have been populated with data submitted to Ofgem by the DNOs. The output from the models therefore reflects the input data comprising individual DNO data, practices and from these aggregate DNO data which has been used to create 'industry-level' data. The principle that has been applied is that the output of the models should reflect a general industry view against which each DNO's submission can be compared. In respect of the modelling of non-load related expenditure, no material age dispersion across DNOs has been observed for the main asset classes. Consequently any major difference between DNO submission and model output is likely to reflect a difference with general industry practice in terms of replacement or refurbishment policy and unit costs. Information provided by a DNO has been assumed to be correct although concerns on unsupported changes to the asset age profiles of certain DNOs have been raised with Ofgem.

In forming a "PB Power" opinion of the proposed allowance, we have observed the approach set out above. Our modelling has been used as a guide and, where expenditure differing from that indicated by the model has been justified and is in keeping with Base Case Scenario, we have duly taken account of such differences.

We would also like to take the opportunity of expressing our appreciation of the time taken and courtesy extended by the staffs of Ofgem and the DNOs during meetings and in responding to our queries.

EXECUTIVE SUMMARY

The following table summarises SHEPD's adjusted DPCR3 projection, adjusted DPCR4 forecast (submission), PB Power's modelling results and view of proposed expenditure.

Expenditure Category	Adjusted DPCR3 Projection (£m)	Adjusted DPCR4 Forecast (£m)	Model Output (£m)	PB Power Opinion (£m)	PB Power Comments
Load Related Expenditure - Gross	109.5	113.0	104.2	113.0	The output of the model is some £8.8m lower than SHEPD's load-related expenditure forecast for DPCR4, reflecting that the proposed expenditure is high in relation to the forecast increase in units distributed. However as the difference between SHEPD's forecast and model output is small and as SHEPD's forecasting procedures appear to be thorough, we would consider SHEPD's forecast to be reasonable.
Customer Contributions	(57.5)	(58.0)		(58.0)	The customer contribution is an estimate (based on data provided by SHEPD) as SHEPD has not provided new connections or customer contributions in its submission.
LRE Net	**52.0**	**55.0**		**55.0**	
Asset Replacement	113.2	156.3	128.4	133.4	For overhead lines and cables the model predicts appreciably higher expenditure than SHEPD's submission and accordingly we would propose that SHEPD's submission be allowed. For substations the model predicts a lower expenditure and an additional allowance has been made for replacement due to substation corrosion.
Other	33.9	27.6		27.6	£27.6m comprises £1m SCADA, £10.7 metering and £15.9m fault capex, but excludes ESQCR.
NLRE Total	**147.1**	**183.9**		**161.0**	
Non Operational	1.8	2.0		2.0	
DNO Total	**200.9**	**240.9**		**218.0**	
DNO Total				*189.4*	*As Ofgem Sep 04 paper, excl. meters, faults, non operational and ESQCR.*

BASE CASE SUBMISSION

PB Power's review is of the Base Case capex forecasts excluding diversions, metering, fault capex and non-operational capex. Fault expenditure is considered separately. Where appropriate the forecasts and DPCR3 projections have been adjusted for the funding of the pension deficit, capitalised overheads, inter-company margins and lane rentals in line with figures provided by the DNOs in their submissions and summarised by Ofgem. Where companies have indicated a loss of new connections market share, PB Power has also made adjustments to gross load related expenditure to reflect the total connections market.

The SHEPD forecasts have had no adjustment for funding a pension deficit, capitalised overheads, inter-company margins and lane rentals.

Our principal findings are summarised below.

Load related expenditure

- The SHEPD load related capex forecast for DPCR4 (£113m gross, £55m net) which compares with the DPCR3 projection (£109m gross, £52m net).
- The figure of £113.0m gross for the adjusted DPCR4 forecast was calculated by PB Power from an estimate of gross capital costs in providing connections of £58m, based on an estimate provided by SEPD.

Non-load related expenditure

- For DPCR4 SHEPD proposes non-load related replacement expenditure of £156.3m, being some £43.1m higher than the DPCR3 projection. The increase in expenditure is driven substantially by the replacement rates for substations.
- The increase in expenditure on substations results from an increase in the replacement rate of transformers and switchgear. For example the annual replacement rate of 11 kV GMTs has increased from 2% in DPCR3 to 3% in DPCR4 (£2.7m over DPCR4) and the annual replacement rate of 11 kV PMTs has increased from 0.8% in DPCR3 to 1.0% in DPCR4 (£1.0m over DPCR4). The underlying reasons for the increase in replacement rates across all substation assets has been discussed with SHEPD and an additional allowance has been made for corrosion of substations.
- The SHEPD proposal to strengthen 6,500km of overhead line over a 20-year period at a cost in DPCR4 of £22.35m represents an improvement in the resilience of the network rather than asset replacement. This expenditure could arguably be therefore moved into the Quality of Supply case or the DNO case.
- SHEPD has extended asset lives and inspection intervals to levels more than other DNOs. As SHEPD appears to be extending the envelope of asset lives there may be an issue of stewardship in the long term, we suggest that consideration be given to reviewing the reporting and audit of the condition of assets following the ARM survey report.

We would also make the following general comments:

- PB Power's non-load related modelling is based on the asset lives provided by DNOs. Subsequent refinements have been made to this modelling to reflect PB Power's view of efficient DNO policies and practice.

- There is some concern about the comparability of data between DNOs due to different policies applied by DNOs, particularly the boundary between fault and non-fault replacement and capitalisation of overheads.

- The data presented in this appendix includes comparisons between DPCR3 allowances, DPCR3 projections and DPCR4 forecasts. Care needs to be taken in reviewing these figures in respect of the following:

  - The DPCR3 allowance included £2.30 per customer per year (1997/98 prices) capex for quality of supply[1], which is not separately identified in the DPCR3 projections and is not included in the Base Case DPCR4 forecast.

Ofgem scenario/sensitivity

- SHEPD has identified one main work stream, rural automation, to produce the 2010 quality of supply improvements. The SHEPD proposal would cost £4.1m and would produce improvements of 2.7 CML and 1.35 CI.
- The QoS and sensitivities and accelerated line upgrade analysis has been undertaken at a detailed level using the standard SHEPD risk analysis and decision making tools and therefore the results and expenditure have a high degree of reliability.
- The resilience and amenity undergrounding analysis has been undertaken at a high level it is therefore not possible to give a quantified estimate of how much these programme would benefit resilience.

DNO alternative case

- SHEPD considers that the proposals set out under their DNO Scenario offer represents a measured and sensible approach to network investment, builds on the submitted Base Case and reflects a worthwhile improvement to customer service. Given that the SHEPD analysis has been undertaken at a detailed level using the standard SHEPD risk analysis and decision making tools we consider that the results and expenditure have a high degree of reliability and the proposals are reasonable.

[1] Ofgem DPCR 3 Final Proposals Paper December 1999 para 3.14 page 28

PB POWER VIEW ON LOAD RELATED AND NON LOAD RELATED ALLOWANCES

Load-related expenditure

The output of the model is some £8.8m lower than SHEPD's load-related expenditure forecast for DPCR4, reflecting that the proposed expenditure is high in relation to the forecast increase in units distributed. However as the difference between SHEPD's forecast and model output is small and as SHEPD's forecasting procedures appear to be thorough, we would consider SHEPD's forecast to be reasonable.

Non-load related expenditure

For overhead lines and cables the model predicts appreciably higher expenditure than SHEPD's submission and accordingly we would propose that SHEPD's submission be allowed. For substations the model predicts a lower expenditure which accordingly is proposed as the allowance.

In PB Power's opinion the non-load related expenditure should be the model output of £128.4m plus £5m for corrosion of substations, a total of £133.4m. This amount excludes ESQCR related expenditure, SCADA, metering and fault capital expenditure. Furthermore ESQCR related expenditure has been excluded from the corresponding overall total as the matter of ESQCR related expenditure is being considered separately by Ofgem.

Conclusion

The above considerations would indicate that the SHEPD submission the allowance for the Base Case capex should be £218m.

1. INTRODUCTION

The Office of Gas and Electricity Markets (Ofgem) appointed PB Power to provide support for the 2005 Distribution Price Control Review (DPCR4) covering aspects of capital expenditure and repairs and maintenance forecasting, excluding distributed generation which is covered by a separate review. The project is in two parts.

- Part 1, covered the systems, processes, assumptions, asset risk management and data used by Distribution Network Operators (DNOs) to forecast capital expenditure, and an analysis of variances and efficiency gains in the HBPQ period.
- This Part 2 report provides an analysis of forecast expenditure for the five year period to 31 March 2010 and builds on information obtained in Part 1 of the project.

Ofgem published the Forecast Business Plan Questionnaire (FBPQ) in October 2003, prior to appointing PB Power. Each DNO was requested to provide forecasts of future capital expenditure requirements against 3 scenarios: the Base Case Scenario; the Ofgem Scenarios/Sensitivities; and the DNO Alternative scenario.

The Base Case is intended to reflect the forecast investment requirement that would maintain existing network quality of supply performance and network fault rates together with the same level of network resilience for the period to 2020.

The Ofgem Scenarios/Sensitivities set out network performance improvement targets for 2010 and 2020 with sensitivities of ± 2% on customer interruptions and ± 5% on customer minutes lost of the 2010 targets. The targets are based on Ofgem’s view depending on the nature of each of the DNO networks.

The DNO Alternative Scenario is intended to reflect the DNO view of the efficient level of capital expenditure required to meet the outputs they consider appropriate for their area of supply.

The PB Power review of the DNO forecasts was undertaken as follows:

a. Further questions and visits to companies to inform a review of each DNO capital expenditure forecast to give a bottom up view of the assumptions, risk assessments and justifications put forward by DNO’s for their Base Case forecast, and a high level review of the Ofgem and DNO scenarios.

b. For the Base Case non-load related expenditure, a comparison of the DNO forecast with the output a PB Power model forecast using industry average weighted asset replacement profiles and PB Power’s unit costs.

c. For the Base Case load-related expenditure a benchmarked comparison of the each DNO forecast with a PB Power forecast using a PB Power model based on the methodology set out in Appendix D.

d. From consideration of the above we have formed a “PB Power opinion” of the proposed allowance. Options for the Base Case capital expenditure allowance taking into a account the benchmarking in (b), (c) and (d) above, identifying areas where the DNO expenditure may be higher or lower than the benchmark based on local factors identified during the visits. A qualitative comment on merit of the Ofgem and DNO scenarios is also provided.

As indicated above Ofgem provided criteria for the Base Case forecasts. The DNOs forecasts are based on different assumptions included in the DNO FBPQ submissions. As instructed by Ofgem, adjustments have been made to the DNO forecasts to take account of differing treatments of pension funding deficits, capitalised overheads, intercompany margins and lane rentals. Where appropriate the load-related expenditure, as submitted has been grossed up to take the cost of all connections into account including where these may have been provided by third parties.

In our review of asset replacement expenditure, only non-fault expenditure has been considered. Other items in non-load related expenditure namely diversions, SCADA, metering and fault capital expenditure have been treated as a pass-through. No assessment has been made of non-operational capital expenditure.

2. DNO SUBMISSIONS

2.1 Base case

2.1.1 General

SHEPD's approach to forecasting the Capex projections in the Base Case has been to:

- include non load related expenditure to offset network deterioration and keep quality of supply broadly constant
- include load related expenditure to provide for:
  - Compliance with Licence Condition ER P2/5 – Security of Supply.
  - Overloaded circuits, plant and equipment.
  - Reinforcement due to fault level limitations.
  - New Business – 25% rule.
  - Voltage outside statutory limits.

The SHEPD philosophy with regard to forecasting load and non-load expenditure is covered in the following SHEPD policy documents.

- Underground cable replacement
- Rising mains refurbishment
- Load related reinforcement (Major Projects at Primary level and above)
- Non Load related reinforcement (Major Projects at Primary level and above)
- HV Ground mounted substation refurbishment
- EHV/HV Overhead Line refurbishment strategy
- Embedded Diesel Generating Plant

The following table presents the adjusted DPCR4 forecast expenditure together with the corresponding DPCR3 allowance and projection.

Base case

Table 2.1 - Base Case Capex Projections (£m at 2003/03 prices)

Item	DPCR3 Allowance	Adjusted DPCR 3 Projection	DPCR 4 Forecast	DPCR4 Corrections	Revised DPCR4 Forecast
Gross Load Related	**108.4**	**109.5**	**113.0**	**0.0**	**113.0**
Non Load Related	**197.8**	**147.1**	**183.9**	**0.0**	**183.9**
Gross Capex less Non Op Capex	***306.2***	***256.6***	***296.9***	***0.0***	***296.9***
Non Op Capex (Not Assessed)	16.8	1.8	2.0	0.0	2.0
Total Gross Capex	**323.0**	**258.4**	**298.9**	**0.0**	**298.9**
Contributions	-27.9	-57.5	-58.0	0.0	-58.0
Net Load Related	**80.5**	**52.0**	**55.0**	**0.0**	**55.0**
Total Net Capex	**295.0**	**200.9**	**240.9**	**0.0**	**240.9**
Non Load Related Summary					
Replacement	167.7	113.2	148.7	0.0	148.7
ESQCR			4.1	0.0	4.1
Heath & Safety			0.0	0.0	0.0
Environment			3.5	0.0	3.5
Sub Total - Model Comparison	**167.7**	**113.2**	**156.3**	**0.0**	**156.3**
Diversions	17.9	0.0	0.0	0.0	0.0
SCADA		0.0	1.0	0.0	1.0
Sub Total	***185.5***	***113.2***	***157.3***	***0.0***	***157.3***
Metering (Not Assessed)	12.3	24.8	10.7	0.0	10.7
Sub Total	***197.8***	***138.0***	***168.0***	***0.0***	***168.0***
Fault Capex (Not Assessed)		9.1	15.9	0.0	15.9
Non Load Related Total	**197.8**	**147.1**	**183.9**	**0.0**	**183.9**

The forecast has been adjusted for:

- gross market LRE adjustment, to take account of customer connection expenditure by third parties
- pension funding deficit
- capitalised overheads
- inter-company margin and
- lane rentals.

The adjusted DPCR4 forecast is presented in the table below.

Table 2.2 – Adjusted DPCR4 Base Case Capex Projection (£m at 2003/03 prices)

	Adjustment to DPCR4 Forecast					
Item	**Gross Market LRE Adjustment**	**Pension Funding Deficit**	**Capitalised Overhead**	**Inter-company Margin**	**Lane Rentals Adjustment**	**Adjusted DPCR4 Forecast**
Gross Load Related	0.0	0.0	0.0	0.0	0.0	**113.0**
Non Load Related		0.0	0.0	0.0	0.0	**183.9**
Gross Capex less Non Op Capex	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	**296.9**
Non Op Capex (Not Assessed)						**2.0**
Total Gross Capex	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**298.9**
Contributions	0.0	0.0	0.0	0.0	0.0	-58.0
Net Load Related	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**55.0**
Total Net Capex	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**240.9**
Non Load Related Summary						
Replacement		0.0	0.0	0.0	0.0	146.7
ESQCR		0.0	0.0	0.0	0.0	6.1
Heath & Safety		0.0	0.0	0.0	0.0	0.0
Environment		0.0	0.0	0.0	0.0	3.5
Sub Total - Model Comparison		**0.0**	**0.0**	**0.0**	**0.0**	**156.3**
Diversions		0.0	0.0	0.0	0.0	-
SCADA		0.0	0.0	0.0	0.0	1.0
Sub Total		***0.0***	***0.0***	***0.0***	***0.0***	***157.3***
Metering (Not Assessed)		0.0	0.0	0.0	0.0	10.7
Sub Total		***0.0***	***0.0***	***0.0***	***0.0***	***168.0***
Fault Capex (Not Assessed)		0.0	0.0	0.0	0.0	15.9
Non Load Related Total		**0.0**	**0.0**	**0.0**	**0.0**	**183.9**
Total Adjustments	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Load related capex

Network reinforcement

To produce future demand forecasts SHEPD use factors such as historic growth trend, local economic factors derived from district and county structure plans and known local developments that are added to actual average cold spell corrected maximum demand. The forecast obtained is compared with the forecast from the previous year to identify any step changes in demand. Any such step changes are rationalised to produce a credible future forecast.

To derive a forecast at the 132/33 kV substation level SHEPD aggregate the maximum demand of all primary substations associated with a bulk supply point (BSP). The aggregated maximum demand of the current year is also compared with the actual maximum demand obtained via SCADA at the BSP. The ratio of actual maximum demand to aggregated maximum demand provides a diversity factor that is used to convert aggregated maximum demand to simultaneous maximum demand (SMD). The SMD is used to determine compliance with ER P2/5.

In the SHEPD area there are over 400 primary substations and the 2002/03 demand forecast shows that during DPCR4 about 10 substations will exceed their firm capacity and will require reinforcement, details of these are provided in Section 0 of Appendix A.

As the demand on plant and equipment normally increases each year SHEPD undertake a high-level system analysis to identify overloaded plant, equipment and circuits. Based on the 2002/03 demand forecast and power system analysis under N-1 and N-2 (as appropriate) SHEPD estimate that nine 33 kV circuits and twelve 33/11 kV transformers will become overloaded during DPCR4; details of these are provided in Section 0 of Appendix A.

2.1.1.1 New connections forecast expenditure

At the start of DPCR3 SHEPD changed the set up of its new connection business to a 'ring fenced' business within SHEPD. The business is incentivised to increase profit through efficiency gains and hence minimise the amount of capital required from the 'wires' business. The connections business has been combined into one managed unit within the SSE Group (Scottish Hydro-Electric and Southern Electric). The result of this is that SHEPD have not included new connections or customer contributions in their submission.

2.1.1.2 Comments and issues associated with the load related expenditure forecast

i. The SHEPD load related capex submission (£55m) is similar to the forecast for DPCR3 (£52m). . SHEPD plan to apply full costs to new business connections during DPCR4 and have therefore not included any allowances in their forecasts other than that for final connections and a sum to cover allowances for schemes quoted pre 2005 but which continue into DPCR4.

ii. We consider the basis of the load related expenditure forecast to be sound as it relies on well established demand forecasting techniques and power system studies that identify detailed site-specific reinforcement requirements.

2.1.2 Non-load related capex

The main drivers for non-load related capital expenditure in SHEPD are:

- Asset Condition
- Network Security
- Fault Performance
- Spares and obsolescence

- Safety
- Age

SHEPD prepare a five-year non-load related capital expenditure plan that is primarily based on asset age and comparison with assigned useful asset life. Other information such as external and internal condition and known design problems is used to priorities the five-year plan. A yearly non-load related budget is created using the information in the five-year plan and actual asset condition information from the field. The SHEPD decision making process, which is based on a scoring method that takes in to account the five main drivers listed above, includes whether to replace, refurbish or carry out additional maintenance.

A comparison of asset lives shows that SHEPD's asset lives for plant and equipment are among the longest in the UK. Examination of asset ages shows that SHEPD's assets are generally around the average age across the industry. The increase in expenditure proposed by SHEPD for DPCR4 over DPCR3 is driven substantially by the age profiles of plant and equipment.

The three major areas of non-fault replacement in SHEPD are substations, overhead lines and underground cables; these areas are further discussed below.

2.1.2.1 Substation non-fault replacement

The classification of substations includes mainly switchgear and transformers. Details of the proposed replacement levels for transformers and switchgear are provided in Section 0 of Appendix A. The replacement rates proposed by SHEPD of 7.3% for transformers and 7.6% for switchgear are consistent with the SHEPD risk assessment replacement process and are indicative of very long asset lives. The total capex proposed for substations is £48.6m.

2.1.2.2 Overhead lines non-fault replacement

The SHEPD proposals for overhead line investment are based on the refurbishment cycle of 12 years for all overhead lines plus short-term actions to ensure that the risk of incident or loss of supply is managed to within acceptable levels during DPCR4. The capex proposals are based on a consideration of the following areas:

- Under design of the existing overhead lines
- New requirements driven by changes to the ESQC Regulations
- High Risk Sites
- LV Lines

SHEPD consider that 6,500km of their overhead lines are under-designed (not fit for purpose) and are likely to fail in severe weather. SHEPD propose to address this risk over a period of 20 years, which means that during DPCR4 they propose to line strengthen 360km each year at an annual cost of £4.47m (£22.35m in total for DPCR4).

In addition SHEPD estimate that the following expenditures would be required annually for refurbishment of overhead lines:

- LV light refurbishment, 378km, £1.96m

- HV light refurbishment, 1440km, £3.2m
- EHV light refurbishment, 423km, £1.93m and
- LV major refurbishment, 62km, £1.86m.

The corresponding annual expenditure on overhead line refurbishment, including strengthening of HV lines and meeting the requirements of ESQCR would be about £15m.

SHEPD consider that the introduction of the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR) have introduced a number of new duties for DNOs. In particular, the new regulations have driven the need for additional investment to address two new requirements:

- Existing bare LV conductors within 3m of habitation will require to be replaced with insulated conductor or ABC. SHEPD estimate £520k per annum (£2.6m in total for DPCR4)
- All overhead lines and substations require risk assessment and the results catalogued on a new database. SHEPD estimate that over DPC4 the risk assessment and database establishment will cost £1.5m. In addition an annual expenditure of £500k per annum will be required to address the risks identified by the risk assessment, particularly at leisure sites including playfields, camping areas and fishing areas.

SHEPD have budgeted £4.1m of non-load related capex to meet the requirements of ESQCR, comprising £2.6m for replacing 100km of LV bare conductor line and £1.5m for high risk site assessments. (SHEPD Company Case item 6) refers).

SHEPD also propose to carry out major refurbishment of around 62km per annum of LV overhead lines in the more highly populated village networks at an overall cost of £1.86m over the DPC4 period. The refurbishment will constitute a mixture of ABC, undergrounding and open wire refurbishment.

2.1.2.3 Underground cables non-fault replacement

SHEPD indicate that expenditure on underground cables is forecast to increase slightly from DPCR3 to DPCR4. This reflects deteriorating fault rates that will be addressed by SHEPD on an ad hoc basis. The SHEPD proposals for underground cable replacement are as follows:

- replace 25km of LV plastic waveform cable at a cost of £4m
- replace 30km of HV cable at a cost of £3.5m
- replace 19.5km of 33 kV EHV cable at a cost of £3.3m

In addition to the cable replacement expenditure identified above SHEPD have included a total of £3.6m over DPCR4 to address environmental concerns regarding fluid filled cables. SHEPD propose that cables within 100m of watercourses will be overlaid with solid cable and high-risk joints will be encased in concrete ‘coffins’ to contain possible leaks at a cost of £1.6m. Also, to contain the risks associated with oil leaks from transformers and switchgear, SHEPD have developed a system to categorise and prioritise sites and propose to spend £2.0m on bunding improvements to substations over DPCR4.

The replacement rates proposed by SHEPD are less than 1% of the cable populations and are consistent with the SHEPD risk assessment and condition based replacement policies. We therefore consider the proposals to be reasonable.

2.1.3 Comments on and issues associated with the non-load related capex forecast

i. SHEPD have extended asset lives and inspection intervals to levels beyond any of the other DNOs. As SHEPD appear to be extending the envelope of asset lives there may be an issue of stewardship in the long term, we suggest that consideration be given to review the reporting and audit of condition of assets following the ARM survey report.

ii. The SHEPD proposal to strengthen 6,500km of overhead line over a 20-year period at a cost in DPCR4 of £22.35m represents an improvement in the resilience of the network rather than asset replacement. Nevertheless, taking into consideration the severe weather conditions prevalent in SHEPD's area and the long-term nature of the proposed solution, we consider the proposals to be reasonable.

iii. The SHEPD proposals to meet the ESQCR requirements costing a total of £4.1m over DPCR4 have been included in the Base Case. £1.5m of this total is associated with the establishment of the risk assessment database and undertaking the risk assessments and represents 50% of the total for SSE. Subject to ongoing discussions between Ofgem and DTI in respect of compliance with ESQCR, we would consider the basis of the forecast of capex associated with ESQCR to be reasonable.

iv. We consider the basis of the non-load related expenditure forecast to be sound as it relies on well-documented policies and structured risk, RCM and condition processes that identify asset specific replacement requirements.

Quality of supply/sensitivity scenarios

Network performance improvements

Table 2.3 sets out the proposed network performance targets for 2010 and 2020.

Table 2.3 - Proposed Network Performance Targets

02/03 actual		01/02 & 02/03 ave		2010 Scenario		2020 Scenario		(ave/2010)%	
CI	CML	CI	CML	CI	CML	CI	CML	CI	CML
83	71.5	94.2	99.4	98.8	96.3	98.8	91.7	95%	103%

SHEPD's quality of supply submission is described more fully in Appendix B.

2.1.3.1 Quality of supply – improvement scenario

SHEPD have identified one main work stream, rural automation, to produce the 2010 quality of supply improvements. SHEPD would address 216 circuits at a cost of £4.1m that would produce improvements of 2.7 CML and 1.35 CI.

2.1.3.2 Quality of supply – sensitivities

SHEPD consider that the ±2% scenarios and the +5% scenario would be met by their Base Case as submitted.

To meet the CML performance reduced by 5% relative to QoS Improvement Scenario SHEPD propose to undertake further rural automation on both the HV and EHV networks. The total estimated cost of the automation measures is £10m and the performance improvements of 2.92CML and 1.46 CI for the HV automation and 1.9 CML and negligible CI's for the EHV automation.

2.1.3.3 Accelerated line upgrade

To meet the accelerated overhead line up rating target SHEPD estimate that they would need to refurbish an additional 132km per year above the Base Case. This represents an additional 660km over the Base Case Scenario that would cost £8.65m and would provide an estimated 0.05 CML and 0.02 CI benefit.

2.1.3.4 Undergrounding existing overhead lines (network resilience)

In order to underground 2% of their HV overhead network SHEPD estimate that they would need to address around 400km of lines at a cost of approximately £27m. As well as giving resilience benefits this scenario would improve network performance by about 0.84 CML and 0.29 CI.

2.1.3.5 Undergrounding existing overhead lines (amenity value)

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty SHEPD estimate a cost £214m.

2.1.3.6 Comments and issues associated with the quality of supply scenarios

i. SHEPD consider that the proposals set out under their DNO Scenario offer represents a measured and sensible approach to network investment, builds on the submitted Base Case and reflects a worthwhile improvement to customer service.

ii. The QoS and sensitivities and accelerated line upgrade analysis has been undertaken at a detailed level using the standard SHEPD risk analysis and decision making tools and therefore the results and expenditure have a high degree of reliability.

iii. The resilience and amenity undergrounding analysis has been undertaken at a high level and SHEPD state it is not possible to give a quantified estimate of how much these programme would benefit resilience as the factors that make up such an equation are subject to error margins that exceed any possible benefit.

2.2 DNO alternative scenario

The SHEPD alternative case covers the following areas:

- Network resilience and performance
  - an additional 900km of Line Strengthening (£11.7m) over the Base Case to further improve resilience
  - bare wire HV circuits will have pole-mounted reclosers and automatic sectioning links fitted (£5m).
  - undergrounding 100km of overhead lines (£6.5m)
  - Environmental factors, oil containment (£3.6m)
- ESQC Regulations (£4.1m)
- Lane rentals (£10m)
- Token pre-payment meters (£7.0m)

The total additional cost of the SHEPD alternative over the Base Case is £23.2m and is related to the Network resilience and performance areas only. The costs associated with environmental factors, ESQC regulations, lane rentals and token pre-payment meters are included in the Base Case.

3. PB POWER MODELLING AND COMPARISONS

3.1 Introduction

PB Power has carried out modelling of forecast expenditure using both DNO data and PB Power data with a view to understanding better how DNOs have arrived at forecast expenditure and with a view to informing Ofgem of issues that may be considered in arriving at allowances for DPCR4.

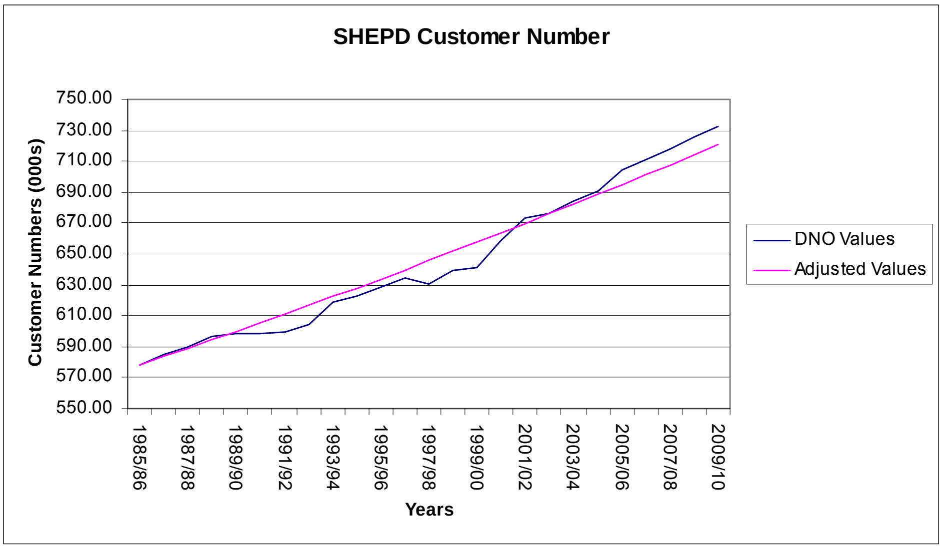
Detailed descriptions of the models are provided in Appendices D and E and the following sections discuss the validation and adjustment of the input variables and the model outputs.

3.2 Load related expenditure

3.2.1 Model inputs

SHEPD historic customer numbers exhibit step changes and noise. PB Power has removed the step changes and noise by applying an average growth rate of 0.91% backwards from 2002/03. Also the forecast growth rate from 2003/04 is higher than that of the historical data, therefore the average growth rate has been applied to the forecast years.

Table 3.1 - Adjustment of Customer Numbers



3.2.2 Model outputs

The following table sets out the model output compared to DPCR 2 & 3 expenditure and DPCR4 submission. The DPCR4 submission for LRE has been increased to reinstate an estimate of the connections expenditure.

Table 3.2 - Load Related Capex Model Outputs

LRE DCPR2 (excluding generation)	LRE DCPR3 (excluding generation)	Submitted LRE Gross DCPR04 (excluding generation)	Model Output LRE for DCPR4 using Combined Median projection
(£m)	(£m)	(£m)	(£m)
125	106	113	104.2

3.2.3 Load-related expenditure modelling comments

The output of the model is some £8.8m lower than SHEPD's load-related expenditure forecast for DPCR4, reflecting that the proposed expenditure is high in relation to the forecast increase in units distributed. However as the difference is small and as SHEPD's forecasting procedures appear to be thorough, we would consider SHEPD's forecast to be reasonable.

3.3 Non-load related expenditure

3.3.1 Model inputs

No specific model input adjustments were made for SHEPD.

With minor exceptions assets were modelled on an age based replacement profile basis.

3.3.2 Model outputs

Table 3.3 below provides a comparison between the DNO submissions and the model outputs for the main asset classes using the PB Power asset replacement curves and unit costs.

Table 3.3 - Comparison of NLRE Model Outputs with DNO Submission

Submission	FBPQ Table 26	Adjusted submission	Combined	Adjusted submission	Model output	Bench-marked output	PB Power Opinion
Lines	77.9	77.9	Lines & services	79.1	160.2	79.1	
Cables	11.1	11.1	Cables & services	11.5	19.1	11.5	
Transformers	22.4	22.4	Substations	52.1	30.4	26.4	
Switchgear	28.2	28.2	Part Submission Total	142.7	209.6	116.9	
Services and Lines	1.5	1.5					
SMC	1.4	1.4		1.4			
Other Substations	1.5	1.5					
Other Not Modeled	12.3	12.3	Other Not Modeled	12.3		11.4	
Total	156.3	156.3	Total	156.3		128.4	133.4

Note: £2m underground cable non-fault replacement expenditure transferred to fault replacement as per SSE e-mail 20/03/04.

3.3.3 Non-load related expenditure modelling comments

For overhead lines, particularly HV lines, the model predicts appreciably higher expenditure than SHEPD’s submission. Overall while the model predicts lower quantities than SHEPD which has adopted a 12-year cyclic (mainly) light refurbishment policy, SHEPD’s unit costs for replacement and refurbishment of HV lines are appreciably lower than PB Power’s. We have, therefore, a concern over the long-term sustainability of a light refurbishment policy as reflected in the level of activity indicated by SHEPD’s unit costs. Over the life of an HV line, (45 years, say), we would expect the line to effectively be replaced and a cost of about £33,000 per km (the new build cost) to be incurred. However the weighted unit cost of SHEPD’s light refurbishment and line strengthening is only about £4,400 per km and over a lifetime of four (12 yearly) refurbishment cycles would imply a replacement expenditure of only half the new build cost, indicating that at the end of four refurbishment cycles, the refurbishment work undertaken would be insufficient to return the line to an “as new” condition. The model output after benchmarking is as SHEPD’s submission. We propose therefore that the submission for line expenditure be allowed but that the performance (resilience) of the lines should be monitored under the Asset Risk Management and IIP initiatives going forward.

For cables and services the model is predicting higher expenditure than in SHEPD’s submission, particularly in respect of services. The model output after benchmarking is as SHEPD’s submission.

However for substations the model is predicting lower expenditure than in SHEPD’s submission, both in respect of transformers and switchgear. Some £6.7m of the difference may be accounted for by pole mounted transformer expenditure included in SHEPD’s submission as non-fault expenditure whereas we have excluded pole mounted transformer expenditure from the model as such units have been deemed to be replaced only on fault.

Furthermore the replacement quantities of ground mounted transformers, at both 11kV and 33kV, predicted by the model are appreciably lower than those in SHEPD's submission, despite the average asset lives being similar. It would therefore appear that SHEPD's expenditure on transformers (excluding pole mounted transformers) is about £7m high.

There are discrepancies between quantities of switchgear to be replaced and refurbished between SHEPD's paper on non-load related expenditure and the quantities declared in the FBPQ, preventing a detailed comparison of expenditure on HV ring main units. Nevertheless the replacement of some 61 off 33kV and 243 off 11kV circuit breakers would appear to be high in comparison with the model output, despite the average lives being very similar. The model output after benchmarking for substation expenditure is about half the SHEPD submission.

In PB Power's opinion the non-load related expenditure should be the model output of £128.4m and an additional allowance of £5m for corrosion of substations, totalling £133.4m. This amount excludes ESQCR related expenditure, SCADA, metering and fault capital expenditure. Furthermore ESQCR related expenditure has been excluded from the corresponding overall total as the matter of ESQCR related expenditure is being considered separately by Ofgem.

3.4 PB Power's opinion of allowances

Our findings are summarised in the table below.

Table 3.4 – PB Power's Opinion of Allowances (£m)

Item	Adjusted DPCR 3 Projection	Adjusted DPCR4 Forecast	Model Output, benchmarked	PB Power Opinion
Gross Load Related	**109.5**	**113.0**	**104.2**	**113.0**
Non Load Related	**147.1**	**183.9**		**161.0**
Gross Capex less Non Op Capex	***256.6***	**296.9**		***274.0***
Non Op Capex (Not Assessed)	1.8	**2.0**		2.0
Total Gross Capex	**258.4**	**298.9**		**276.0**
Contributions	-57.5	-58.0		-58.0
Net Load Related	**52.0**	**55.0**		**55.0**
Total Net Capex	**200.9**	**240.9**		**218.0**
Non Load Related Summary				
Replacement	113.2	148.7		
ESQCR		4.1		
Heath & Safety		0.0		
Environment		3.5		
Sub Total - Model Comparison	**113.2**	**156.3**	**128.4**	***133.4***
Diversions	0.0	-		0.0
SCADA	0.0	1.0		1.0
Sub Total	***113.2***	***157.3***		***134.4***
Metering (Not Assessed)	24.8	10.7		10.7
Sub Total	***138.0***	***168.0***		**145.1**
Fault Capex (Not Assessed)	9.1	15.9		15.9
Non Load Related Total	**147.1**	**183.9**		**161.0**

Notes:

- Non operational capital expenditure has not been assessed
- Non-load related expenditure modelling covers all non-load related headings except diversions, metering, fault capex and SCADA
- Metering and fault capex are passed through
- Diversions are passed through, where compliant, with the Base Case the same as for DPCR3
- SCADA is separately assessed but not included in the modelling
- PB Power's model output and Opinion are based on retirement profile modelling and exclude any additional expenditure that may arise under ESQCR legislation.

APPENDIX A
BASE CASE SUBMISSION

APPENDIX A – BASE CASE SUBMISSION

A.1.1 Actual and forecast capital expenditure projection for DPCR3

In Table A.1 below we present the actual and forecast capital expenditure projection for DPCR3. The net load-related expenditure for the period is £66.8m and overall gross capital expenditure £198.1m.

Table A.1 - DPCR3 Actual & Forecast Expenditure

	Actual (£m)					Total
	2000/01	**2001/02**	**2002/03**	**2003/04**	**2004/05**	
Capital Expenditure						
Load Related	15.8	18.5	14.5	10.5	7.5	66.8
Capital Contributions	-	-	-	-	-	-
Non Load Related	24.8	28.0	21.0	24.9	30.8	129.5
Non-operational capex	0.5	0.8	0.5	-	-	1.8
Total Capital Expenditure	41.1	47.3	36.0	35.4	38.3	198.1

The SHEPD philosophy with regard to forecasting load and non-load expenditure is covered in the following policy documents provided by SHEPD.

- Underground cable replacement
- Rising mains refurbishment
- Load related reinforcement (Major Projects at Primary level and above)
- Non Load related refurbishment (Major Projects at Primary level and above)
- HV Ground mounted substation refurbishment
- EHV/HV Overhead Line refurbishment strategy
- Embedded Diesel Generating Plant

The Base Case Projected Capital Expenditure follows the Ofgem FBPQ guidelines and is summarised in **Table A.2 - DPCR4 Base Case Capex Forecasts** below.

Table A.2 - DPCR4 Base Case Capex Forecasts

	Forecast					Total
	2005/06	2006/07	2007/08	2008/09	2009/10	
Capital Expenditure						
Load Related	10.5	11.6	10.0	11.1	11.1	**54.3**
Capital Contributions	-	-	-	-	-	**0.0**
Non Load Related	39.6	34.8	38.5	36.3	34.7	**183.9**
Non-operational capex	0.4	0.4	0.4	0.4	0.4	**2.0**
Total Capital Expenditure	50.5	46.8	48.9	47.8	46.2	**240.2**

Note that the above figures are presented without normalisation.

A.1.2 Projections of future load related capex

SHEPD's load related capital expenditure projections for the Base Case Scenario are as set out in Table A.3 below:

Table A.3 - Base Case Forecast

Load Related Capital Expenditure £m	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Reinforcement	10.5	11.6	10.0	11.1	11.1
New Connections	0	0	0	0	0
LRE Total Gross	10.5	11.6	10.0	11.1	11.1
Customer Contributions	0	0	0	0	0
LRE Total Net	10.5	11.6	10.0	11.1	11.1

A.1.2.1 Network reinforcement

In SHEPD the SCADA system provides actual maximum demand, time and date of maximum demand for each circuit i.e. 11, 33 and 132 kV, for each primary (33/11 kV) substation and bulk supply point (132/33 kV). This information is available for each month of the year and is used to ascertain actual maximum demand. The demand is corrected to Average Cold Spell (ACS) condition.

To produce future forecasts SHEPD use factors such as historic growth trend, local economic factors derived from district and county structure plans and known local developments that are added to actual ACS maximum demand. The forecast thus obtained is compared with the forecast from the previous year to identify any step changes in demand. Any such step changes are rationalised to produce a credible future forecast.

To derive a forecast at the 132/33 kV substation level SHEPD aggregate the maximum demand of all primary substations associated with a bulk supply point (BSP). The aggregated maximum demand of the current year is also compared with the actual maximum demand obtained via SCADA at the BSP. The ratio of actual maximum demand to aggregated maximum demand provides a diversity factor that is used to convert aggregated maximum demand to simultaneous maximum demand (SMD). The SMD is used to determine compliance with ER P2/5.

Table A.4 - SHEPD Simultaneous Maximum Demand Forecast

	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
SMD (MVA)	1642	1669	1684	1700	1710	1722	1729	1735

In the SHEPD area there are over 400 primary substations and the 2002/03 demand forecast shows that during DPCR4 about 10 substations will exceed their firm capacity and will require reinforcement, these are listed in Table A.5 below.

Table A.5 - SHEPD Substation Reinforcement Forecast

Name	Voltage	Incidence of expenditure
Tarbert	33/11 kV	2005/06
Marnoch	33/11 kV	2005/06
Calvine	33/11 kV	2005/06
Thimblerow	33/11 kV	2005/06
Arnish	33/11 kV	2006/07
Aberfeldy	33/11 kV	2006/07
Dalneigh	33/11 kV	2006/07
Ellon	33/11 kV	2006/07
Constable Street	33/11 kV	2006/07
Kintore S'Gear	33 kV	2006/07

The thermal capability of individual plant and circuits is defined at the time of its commissioning. This assigned capability is based on a number of factors such as seasonal capability, cyclic nature of demand, construction details and capability of associated ancillary equipment. As the demand on this plant and equipment normally increases each year SHEPD undertake a high-level system analysis to identify overloaded plant, equipment and circuits, these are recorded in the SHEPD ComPlan system. Based on the 2002/03 demand forecast and a review of the information in the ComPlan system, power system analysis under N-1 and N-2 (as appropriate) undertaken by SHEPD shows that nine 33 kV circuits and twelve 33/11 kV transformers will become overloaded during DPCR4, these are listed in Table A.6, Table A.7 and Table A.8 below.

Table A.6 - SHEPD Circuit Reinforcement Forecast

Circuit	Voltage	Incidence of expenditure
Torr Achilty/Garve	33 kV	2005/06
Shetland	33 kV	2005/06
Keith/Dufftown	33 kV	2006/07
Kintore/Torryburn/Inverurie	33 kV	2007/08
Bowmore/Port Ellen	33 kV	2007/08
Inverness/Hilton/Raigmore	33 kV	2007/08
Inverlochy/Annat	33 kV	2007/08
Inverurie/Insch	33 kV	2008/09
Insch/Fyvie	33 kV	2009/10

Table A.7 - SHEPD Primary Transformer Reinforcement Forecast

Primary Transformer	Voltage	Incidence of expenditure
Kingussie	33/11 kV	2007/08
Mount Pleasant	33/11 kV	2007/08
Ullapool	33/11 kV	2007/08
Coupar Angus	33/11 kV	2007/08
Pollacher	33/11 kV	2008/09
Tyndrum	33/11 kV	2008/09
Longman	33/11 kV	2008/09
Sandbank	33/11 kV	2008/09
Limhillocks	33/11 kV	2009/10
Burghmuir	33/11 kV	2009/10
Craiginches	33/11 kV	2009/10
Inverurie	33/11 kV	2009/10

Table A.8 - SHEPD Diesel Power Station Reinforcement Forecast

Diesel Power Stations	Incidence of expenditure
Bowmor	2007/08
Arnish	2007/08

The plant and equipment installed on the distribution system that is required to make or break fault current are assigned fault ratings, typically manufacturers design ratings. Fault levels can change on distribution systems for the following reasons:

- Modification or change to the transmission system
- Change and/or installation of new equipment that results in reduction in the system impedance
- Reconfiguration of the distribution system.
- Connection of embedded generation

SHEPD have examined their network and have identified the following sites where switchgear will require replacement due to fault levels:

Table A.9 - SHEPD Overstressed Switchgear Forecast

Name	Voltage	Incidence of expenditure
Burghmuir	33 kV	2005/06
Lunanhead	33 kV	2007/08
Keith	33 kV	2008/09
Dunoon	33 kV	2009/10

A.1.2.2 New connections forecast expenditure

A new business request can result in reinforcement of the primary distribution system. The cost of such reinforcement is either charged to the customer or is picked up as system reinforcement cost. The customer is normally not charged the cost of reinforcement under the following cases:

- If the customers demand is less than 25% of the effective capacity at the point of connection.
- If the reinforcement is more than one voltage above the voltage at the point of connection.
- If the reinforcement is already identified before the new business request. In such cases the customer may be charged the brought forward cost to meet customers specific needs.

SHEPD comment that it is difficult to forecast where a single new connection will result in reinforcement of a substation. However, as the forecast demand at each substation captures known schemes the capital expenditure needed during DPCR4 is largely reflected in the SHEPD submission.

SHEPD indicate that on their network there are no known areas where voltage is likely to be outside statutory limits during DPCR4.

At the start of DPCR3 SHEPD changed the set up of its new connection business to a ‘ring fenced’ business within SHEPD. The business is incentivised to increase profit through efficiency gains and hence minimise the amount of capital required from the 'wires' business. The connections business has been combined into one managed unit within the SSE Group (Scottish Hydro-Electric and Southern Electric). The result of this is that SHEPD have not included new connections or customer contributions in their submission.

We consider the basis of the load related expenditure forecast to be sound as it relies on well established demand forecasting techniques and power system studies that identify site-specific reinforcement requirements.

A.1.2.3 Non-load related expenditure

The breakdown of non-load related expenditure projected by SHEPD for the Base Case Scenario is shown in Table A.11 below:

Table A.10 - SHEPD Non-load Replacement Forecast - Base Case

Expenditure Classes	Non-Load Related (£m)					
	2006	2007	2008	2009	2010	Total
Non Fault Replacement	33.0	27.9	31.2	29.8	28.0	**149.8**
Metering	2.7	2.3	2.2	1.9	1.5	**10.7**
Faults	2.4	3.1	3.6	3.1	3.7	**15.9**
Diversions	0.0	0.0	0.0	0.0	0.0	**-**
Health and Safety	0.8	0.8	0.8	0.8	0.8	**4.0**
Environmental	0.7	0.7	0.7	0.7	0.7	**3.5**
Total	**39.6**	**34.8**	**38.5**	**36.3**	**34.7**	**183.9**

A.1.2.3.1 Non fault replacement

The main drivers for non-load related capital expenditure in SHEPD are:

- Asset Condition
- Network Security
- Fault Performance
- Spares and Obsolescence
- Safety
- Age

SHEPD prepare a five-year non-load related capital expenditure plan that is primarily based on asset age and comparison with assigned useful asset life. Other information such as external and internal condition and known design problems is used to prioritise the five-year plan. A yearly non-load related budget is created using the information in the five-year plan and actual asset condition information from the field. The SHEPD decision making process, which is based on a scoring method that takes in to account the five main drivers listed above, includes whether to replace, refurbish or carry out additional maintenance.

A comparison of asset lives shows that SHEPD's asset lives for plant and equipment are among the longest in the UK. Examination of asset ages shows that SHEPD's assets are generally around the average age across the industry. The increase in expenditure proposed by SHEPD for DPCR4 over DPCR3 is driven substantially by the age profiles of plant and equipment.

Following a comprehensive assessment of system risks, and using a Reliability Centred Maintenance (RCM) approach, SHEPD have developed procedures for inspection, maintenance and refurbishment of overhead lines. From the analysis SHEPD have chosen a 12-year cycle refurbishment that also has the financial and efficiency benefit of aligning with a 4-year cycle for inspection.

The SHEPD non-fault replacement capex is broken down as follows:

Table A.11 - Non Fault Replacement Forecast

Expenditure Classes	Non-Load Related (£m)					
	2006	2007	2008	2009	2010	Total
substations	11.4	9.1	9.7	9.7	8.7	**48.6**
overhead lines	14.8	14.8	14.8	14.8	14.7	**73.9**
underground cables	2.3	2.1	3.4	3.4	1.9	**13.1**
submarine cables	1.4	-	-	-	-	**1.4**
service lines and cables	0.3	0.3	0.3	0.3	0.3	**1.5**
meters	2.7	2.3	2.2	1.9	1.5	**10.7**
Tele-control / SCADA	0.2	0.2	0.2	0.2	0.2	**1.0**
Total	**36.1**	**30.6**	**33.8**	**32.1**	**29.9**	**162.5**

Table A.12 includes £10.7m for meters, which when subtracted from the total capex of £160.5m, gives £149.8m non-fault replacement as shown in Table A 11.

Reconciliation with Table 3.3. Table A.11 total of £162.5m less (£10.7m (meters) and £1.0m (SCADA) and £2m cable fault expenditure adjustment)) plus (£4m (health and safety) and £3.5m (environmental) gives £156.3m (Table 3.3).

The three major areas of non-fault replacement in SHEPD are substations, overhead lines and underground cables; these areas are further discussed below.

A.1.2.3.2 Substation non-fault replacement

The classification of substations includes mainly switchgear and transformers. The forecast replacement volumes of switchgear and transformers is shown in Table A.12 below:

Table A.12 - SHEPD Forecast Replacement Volumes of Transformers & Switchgear

Asset Type	Voltage	Total Volume	Replacement Volume	% of Total Volume Replaced
Transformers	33/11 kV	523	38	7.3
Switchgear				
Circuit breakers	33 kV	695	61	8.8
Switchboards[1]	11 kV	403	22	5.4
Total Switchgear		1098	83	7.6

[1] SHEPD proposes replacing 243 off 11kV circuit breakers out of a population of 2911 (i.e. 8.3%).

The replacement rates of 7.3% for transformers and 7.6% for switchgear are consistent with the SHEPD risk assessment replacement process and are indicative of very long asset lives. We would consider these replacement proposals to be reasonable.

A.1.2.3.3 Overhead lines non-fault replacement

The SHEPD proposals for overhead line investment are based on the refurbishment cycle of 12 years for all overhead lines as indicated above plus short-term actions to ensure that the risk of incident or loss of supply is managed to within acceptable levels during DPCR4. The capex proposals are based on a consideration of the following areas:

- Under design of the existing overhead lines
- New requirements driven by changes to the ESQC Regulations
- High Risk Sites
- LV Lines

SHEPD consider that 6,500km of their overhead lines are known to be under-designed (not fit for purpose) and are likely to fail in severe weather. SHEPD propose to address this risk over a period of 20 years, which means that during DPC4 they propose to line strengthen 360km each year at an annual cost of £4.47m (£22.35m in total for DPCR4).

SHEPD consider that the introduction of the Electricity Safety, Quality and Continuity Regulations 2002 have introduced a number of new duties for DNOs. In particular, the new regulations have driven the need for additional investment to address two new requirements:

- Existing bare LV conductors within 3m of habitation will require to be replaced with insulated conductor or ABC. SHEPD estimate £520k per annum (£2.6m in total for DPCR4)
- All overhead lines and substations require risk assessment and the results catalogued on a new database. SHEPD estimate that over DPC4 the risk assessment and database establishment will cost £1.5m. In addition an annual expenditure of £500k per annum will be required to address the risks identified by the risk assessment, particularly at leisure sites including playfields, camping areas and fishing areas.

SHEPD propose to carry out major refurbishment of around 62km per annum of LV overhead lines in the more highly populated village networks at an overall cost of £1.86m during the DPC4 period. The refurbishment will constitute a mixture of ABC, undergrounding and open wire refurbishment.

A.1.2.3.4 Underground cables non-fault replacement

SHEPD indicate that expenditure on underground cables is forecast to increase slightly from DPCR3 to DPCR4. This reflects deteriorating fault rates that will be addressed on an ad hoc basis. The SHEPD proposals for underground cable replacement are as follows:

- Replace 19.5km of 33 kV mainly fluid filled cables at a cost of £3.3m. The expenditure is targeted at the following cables:

- Clayhills - Balnagask (Fluid Filled) 2.5km
- Glenagnes - Overgate No 2 (Fluid Filled) 1km
- Inverness Grid - Waterloo (fluid filled) 8km
- Other Schemes (not yet identified) 8km

- Replace 30km of 11kV cable at a cost of £3.5m
- Replace 25km of LV plastic waveform cable at a cost of £4.0m

In addition to the cable replacement expenditure identified above SHEPD have environmental concerns regarding fluid filled cables. SHEPD have 118km of fluid filled cables on their network and have planned a two-stage programme to keep environmental risks within tolerable levels. Cables within 100m of watercourses will be overlaid with solid cable and high-risk joints will be encased in concrete ‘coffins’ to contain possible leaks. SHEPD plan to spend £1.6m over DPCR4. To contain the risks associated with oil leaks from transformers and switchgear to an acceptable level SHEPD have developed a system to categorise and prioritise sites and propose to spend £2m on bunding improvements to substations over DPCR4.

We consider the basis of the non-load related expenditure forecast to be sound as it relies on well-documented policies and structured risk, RCM and condition processes that identify asset specific replacement requirements.

APPENDIX B

QUALITY OF SUPPLY SCENARIOS

APPENDIX B – QUALITY OF SUPPLY SCENARIOS

B.1.1 Network performance improvements

Table B.1 sets out the proposed network performance targets for 2010 and 2020.

Table B.1 - Proposed Network Performance Targets

02/03 actual		01/02 & 02/03 ave		2010 Scenario		2020 Scenario		(ave/2010)%	
CI	CML	CI	CML	CI	CML	CI	CML	CI	CML
83	71.5	94.2	99.4	98.8	96.3	98.8	91.7	95%	103%

B.1.1.1 Quality of supply – improvement scenario

SHEPD have identified one main work stream, rural automation, to produce the 2010 quality of supply improvements. SHEPD would address 216 circuits at a cost of £4.1m that would produce improvements of 2.7 CML and 1.35 CI.

B.1.1.2 Quality of supply – sensitivities

SHEPD consider that the ±2% scenarios and the +5% scenario would be met by the Base Case as submitted.

For the CML performance reduced by 5% relative to QoS Improvement Scenario SHEPD propose the following additions to the QoS Improvement Scenario:

- Rural HV Automation:- automate 350 additional circuits at a cost of £6.6m that would produce improvements of 2.92 CML and 1.46 CI. This programme would begin to see diminishing returns as the volumes reach these levels.
- Rural EHV Automation:- install Automatic Sectioning Links on EHV network to provide QoS benefits. SHEPD propose to install 1370 units at a cost of £1.37m that would produce improvements of around1.9 CML and negligible CIs.

B.1.1.3 Accelerated line upgrade

SHEPD will be addressing 360km per year of overhead lines under their Base Case as these lines are in poor condition and require refurbishment to maintain performance. To meet the accelerated overhead line up rating target SHEPD would need to refurbish an additional 132km. This represents an additional 660km over and above the Base Case Scenario costing £8.65m and providing an estimated 0.05 CML and 0.02 CI benefit.

B.1.1.4 Undergrounding existing overhead lines (network resilience)

In order to underground 2% of their HV overhead network SHEPD would need to address around 400km of lines at a cost of approximately £27m. As well as giving resilience benefits this scenario would improve network performance by about 0.84 CML and 0.29 CI.

B.1.1.5 Undergrounding existing overhead lines (amenity value)

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty SHEPD estimate a cost £214m.

APPENDIX C

DNO ALTERNATIVE SCENARIO

APPENDIX C – DNO ALTERNATIVE SCENARIO

The SHEPD alternative case covers the following areas:

- Network resilience and performance
    - an additional 900km of Line Strengthening (£11.7m) over the Base Case to further improve resilience
    - bare wire HV circuits will have pole-mounted reclosers and automatic sectioning links fitted (£5m).
    - undergrounding 100km of overhead lines (£6.5m)
- Environmental factors, oil containment (£3.6m)
- ESQC Regulations (£6.1m)
- Lane rentals (£10m)
- Token pre-payment meters (£7.0m)

The total additional cost of the SHEPD alternative over the Base Case is £23.2m and is related to the Network resilience and performance areas only. The costs associated with environmental factors, ESQC regulations, lane rentals and token pre-payment meters are included in the Base Case.

APPENDIX D

LOAD RELATED EXPENDITURE MODELLING

APPENDIX D – LOAD RELATED EXPENDITURE MODELLING

The methodology used in the modelling of the companies forecast for load related expenditure is based on 3 discreet steps:

- a review of the main investment drivers, growth in customer numbers and units distributed (GWh) over the period to be reviewed;
- a comparison of LRE outturns and projections using Modern Equivalent Asset (MEA) values of the companies total network assets and, finally,
- a benchmarking of the relative evolution of each company's LRE against the those of the rest of the companies which included a representation of relative efficiencies and provides an implicit 'Industry view' on the evolution of LRE.

These issues are further discussed below and consideration is given to the period over which the analysis was carried out. Flow charts for the process showing the derivation and combination of the MEAV/Customer and MEAV/GWh factors are included in the Appendix.

D.1.1 Stage 1: Review of growth in customer numbers and units distributed (GWh)

Load related expenditure is affected by two main drivers, customer connections and demand growth, which underpin the majority of the companies' expenditure forecast associated with the New Business and Reinforcement categories respectively. The importance of these variables on the LRE has been reflected by the companies, many of which receive regular specialist advice for forecasting main economic trends in their distribution area. These forecasts have been presented as supporting evidence for the companies' own projections. The companies have assessed the impact of the overall trends and other external factors beyond their control upon customer connections and demand growth in their elaboration of the projected LRE for DPCR4.

The first stage of the review process was therefore to examine the historical evolution of customer and demand growth and its comparison with the company expenditure projections for the next control period and to make adjustments for modelling purposes as necessary.

D.1.1.1 Analysis of demand growth

The companies were asked to submit outturns and forecasts for regulated distributed units at different voltage levels and peak demand including weather corrected (Average Cold Spell, ACS) peak system demand.

Demand growth can be used as a proxy for the overall level of economic activity, which drives new business spend, and is also an indicator of the need to reinforce the system. The data regarding energy growth is comprehensive since it is associated with the Ofgem formula set for the calculation of the regulated revenue of the companies at the start of the present control. Units distributed are generally considered to be a more robust indicator of growth than Maximum Demand.

EHV units are associated with a small number of large customers and are therefore subject to the volatility associated with the activity of a small number of users that, in turn, may have a distorting effect on the observed variability of the company total distributed units. In order to enable a more consistent comparison, the demand growth of HV/LV units only was adopted as an indicator of demand growth.

In order to form an independent view of future demand growth, a review of the comparability between units distributed and a macro-economic indicator (gross value added, GVA) was carried out for each DNO. This analysis is described fully in Appendix E.

Where trend analysis and the independent GVA based view of forecast growth both showed that DNO forecast GWh growth was either higher or lower than anticipated, then the forecast was adjusted by the minimum necessary to match either the trend analysis or the GVA based forecast.

D.1.1.2 Analysis of new customers

There are large fluctuations in reported customer numbers due largely to changes in reporting following the opening of the retail market (and introduction of Meter Point Administration Numbers in about 1998) and the improvements in customer connectivity reporting under the Information and Incentives Project (IIP) in about 2002. The net effect of these fluctuations is to cause a step increase or decrease in the total number of customers connected to the network. For modelling purposes, we consider it necessary to remove such step changes to reflect the true growth in customer numbers. Profiling the customer numbers before and after the fluctuations and shifting the pre-fluctuation profile to align with the post fluctuation profile achieved this.

Where trend analysis showed that the forecast growth in customer numbers was out of step with historic growth, customer numbers were adjusted accordingly. This was considered particularly appropriate for load related modelling since investment normally lags growth by two to three years and any change in growth in the later years of the review period should not influence the investment required in the period.

D.1.2 Stage 2: Benchmarking of LRE using MEA network values

The companies' networks are a reflection of the particular circumstances affecting their areas of supply. These circumstances include not only physical factors, such as geographical location, customer density etc., but also other effects such as company historical design policies, operating practices etc. All these have been historically been built into the existing network and amount to an average network cost per customer which is then specific to each company. As new customers are connected, it can be expected that the additional cost per new customer, over a reasonable period, should approximate to the Modern Equivalent Asset Value (MEA) of the entire network per existing customer. In so doing, the effects of load density or high location-related costs such as underground networks in congested areas are taken into account.

The proposed MEA method is also robust regarding network design policy since all companies work against a common security standard with variations in LPN and SHEPD for network reinforcement. The companies' submissions indicate that the network design does not vary significantly from the requirements embodied in the Licence Security Standard and hence network MEA provides a consistent basis for comparison of the companies.

The procedure followed in the calculation of MEA builds on the information used in the analysis of Non-Load Related expenditure. As part of the Non-Load Related submission the companies were asked to provide age profiles of all the main network assets and a cost database for all the main categories of equipment. The cost data submitted by all the companies was used to inform our own "PBP Cost Database' in order to arrive at an aggregate DNO view of cost levels. Modern Equivalent Asset (MEA) value of the companies' networks was then obtained by cross-multiplying the cost database and the assets database. The results so obtained for the analyses of the LRE are therefore consistent with the figures used in the analysis of NLRE. In order to eliminate distorting variables from the analysis, Generation expenditure is removed from the analysis.

Future expenditure is therefore assessed on a cost per new customer and GWh added compared to MEAV per existing customer and GWh distributed (referred to as the 'Combined Model'); this not only assesses future expenditure compared to past expenditure on a DNO basis but it allows comparisons between companies to be made.

D.1.3 Stage 3: Inter-companies benchmarking of LRE projections

The companies forecast of LRE weighted by their relative MEA per customer as indicated above can be benchmarked among the companies using the "prevalent" industry trend. In the analysis undertaken, the prevalent industry trend has been represented by using the median figure in order to arrive at appropriate factors for all the companies. This benchmarking approach is also consistent with the method adopted in the analysis of NLRE.

The overall trend resulted in MEA value per customer below unity. This indicates than on the whole the companies expect to spend on average during the next control period below what they would have spent historically and is justified on the efficiencies already achieved and forecast into the next period. The lower than unity MEA value per customer also tends to indicate the marginal costs of extending an already mature network. These efficiencies are expected to come from procurement, design and better asset utilisation via greater use of network knowledge relating to demand distribution variations over time, plant loading and system risks. Some companies have planned on reductions in their New Business spend through the loss of a significant proportion of new connections business over the next period which has been duly accounted for in the models in respect of forecast expenditure.

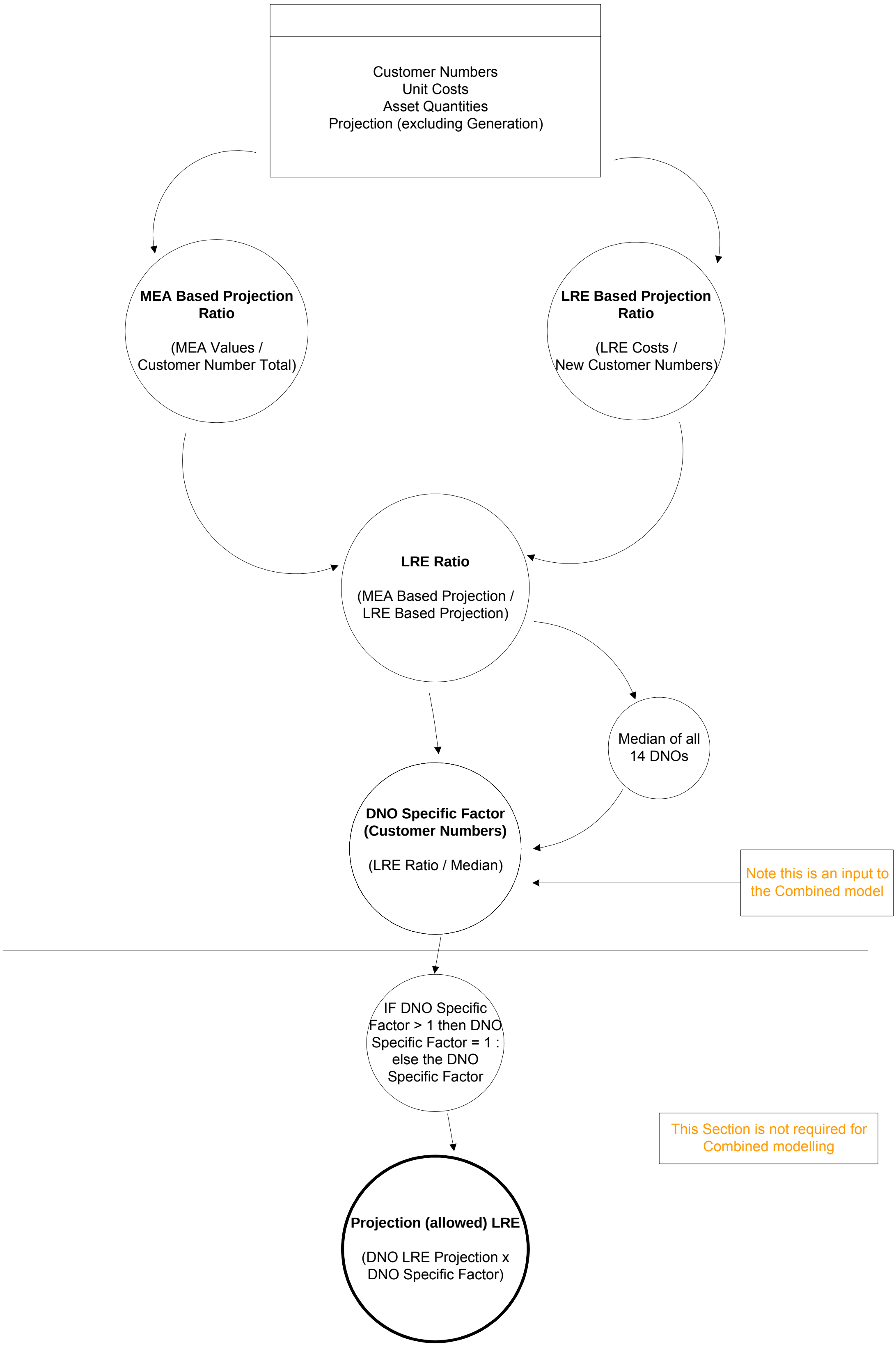
Being benchmarked on a median rather than on an average implies that extremes do not affect the adopted benchmarking position. It also means that the LRE of each company is compared relative to its cost base against the Industry Trend and not in absolute cost terms. This approach recognises therefore the historic cost of distribution within the area of influence of each company and, at the same time, requires the company to drive their costs down in accordance with the prevalent industry trend. In this respect and similarly to the case of Non-Load related expenditure PB Power's view is impartial in that it is the Industry that ultimately sets the trend by which all the companies are measured.

D.1.4 Period of analysis

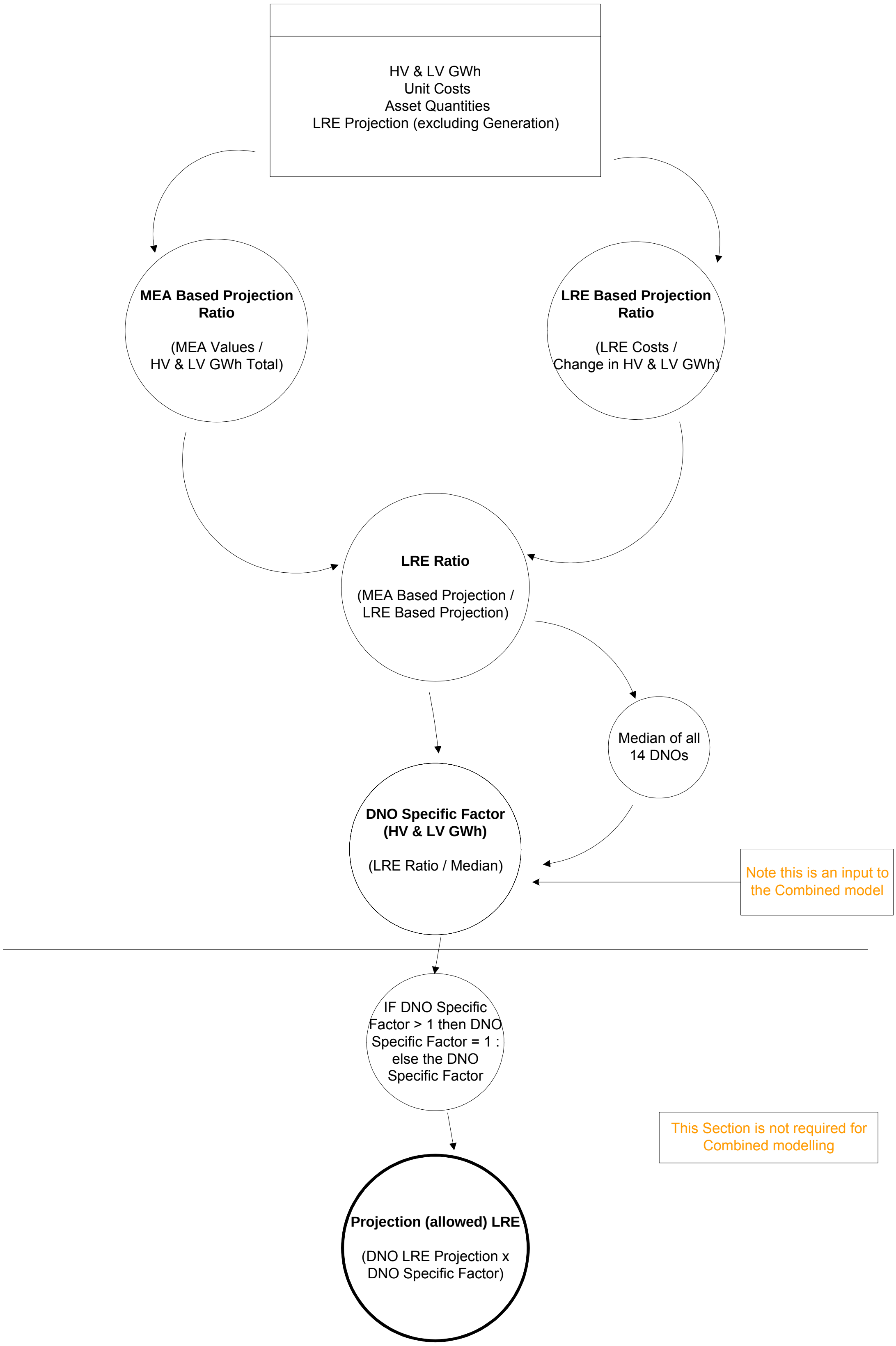
Although each DNO's network is comprised of a large number of smaller networks and that it would be expected that these would have a range of spare capacities depending on local load growth and when individual networks were last reinforced, it is possible that a larger number of the smaller networks would require reinforcement within one regulatory period and fewer in a subsequent period and hence cause a peak in expenditure in one period rather than another.

This issue can be addressed by modelling the expenditure required over a number of review periods and assessing future expenditure requirements by taking into consideration the expenditure already incurred in previous review periods. The modelling carried out in the current review therefore looked at growth and expenditure over DPCR2 and DPCR3 in addition to the forecast growth and expenditure for DPCR4.

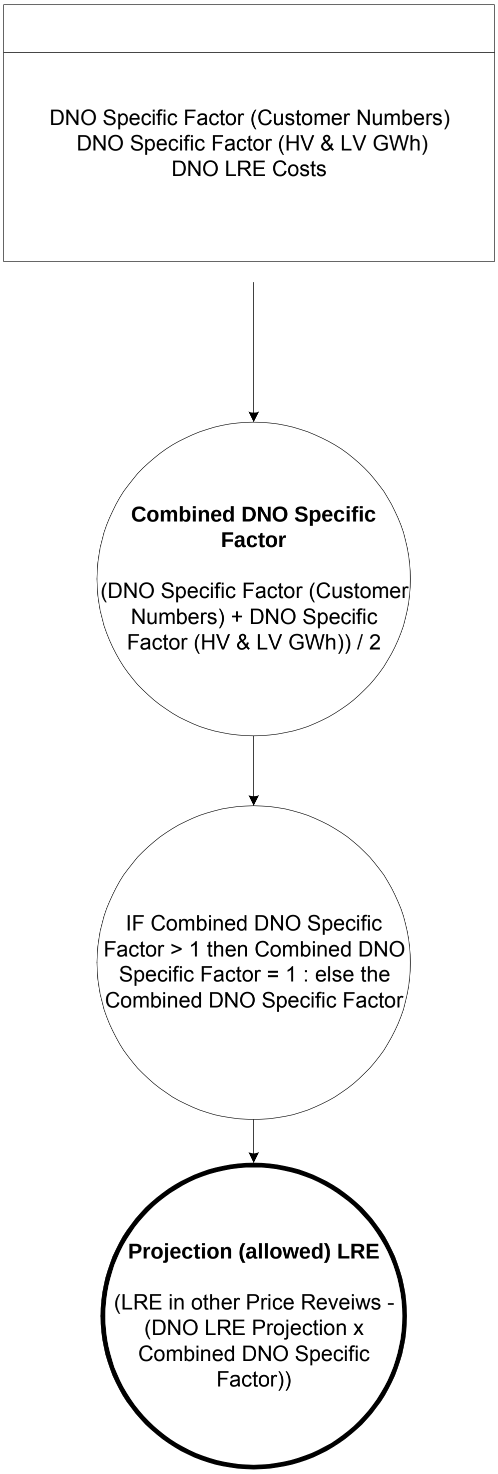
Combined Load Related Expenditure Modelling (Phase 1A Customer Numbers)



Combined Load Related Expenditure Modelling
(Phase 1B Load Forecast HV & LV GWh)



Combined Load Related Expenditure Modeling (Phase 2 Customer Numbers & Load Forecast)



APPENDIX E

DEMAND GROWTH ANALYSIS

APPENDIX E - DEMAND GROWTH ANALYSIS

E.1.1 Introduction

The purpose of the review of the load forecasts provided by the DNOs in their HBPQ and FBPQ submissions is to review the consistency of the load forecasts as a comparator for load-related modelling. Three candidate data sets for comparison purposes were provided as part of the key performance indicators (KPIs), namely customer numbers (by voltage), energy or units distributed (GWh, by voltage) and system power demand (MW). A review was subsequently made of the comparability between units distributed and a macro-economic indicator (gross value added, GVA). Only HV and LV units distributed were considered as the trend in EHV units exhibited volatility, often due to changes (reductions) in manufacturing output.

Although strictly power demand should be the direct capacity driver, energy trends are generally considered to provide a more consistent long-term indicator of load growth. System maximum power demand occurs at a single instant and may vary year on year, although maximum demand data is corrected for weather (average cold spell – ACS correction). Energy is however integrated over time and less prone to instantaneous influences. In this case a simple check was also carried out to show that the change in load factor was not a significant issue.

Customer numbers were declared by voltage level, but not by sector (domestic, commercial and industrial) and some of the DNOs stated that since the separation of distribution and supply businesses such (traditional) disaggregation of load data is no longer available to them. (A similar comment has been made by NGC in the 2002 and 2003 editions of its Seven Year Statement.) Consequently a comparison between, say, new housing starts and net increase in LV customer numbers was not possible without disproportionate effort in this instance.

Furthermore discontinuities were found in DNOs' declarations of customer numbers due to changes in reporting following the opening of the retail market (and introduction of MPAN numbers in about 1998) and the improvements in customer connectivity reporting under the Information and Incentives Project (IIP) in about 2002. These discontinuities particularly affected the calculation of net increases in customer numbers. (For analysis purposes a method of deriving a smoothed projection was subsequently derived and is described in the main text of this report.)

As GVA data was more readily available in a form that could be analysed and as units distributed were viewed as a more consistent comparator than customer numbers, the review of load forecasts was confined to a comparison of increases in units distributed with GVA.

E.1.2 Gross value added (GVA)

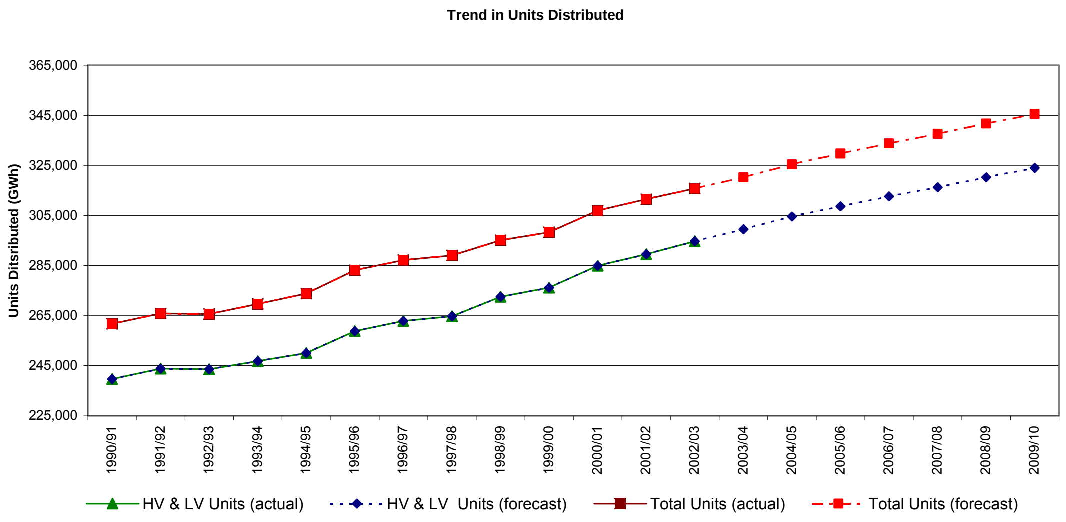
For the purposes of this review, GVA is treated as being synonymous with gross domestic product (GDP). Furthermore Regional Accounts are currently published in terms of GVA1 only. Statistics are published by geographical region in accordance with the Nomenclature of Units for Territorial Statistics (NUTS) classification. NUTS1 covers regions, NUTS2 covers sub-regions and NUTS3 covers unitary authorities or districts. At present NUTS2 data is available for the years 1995 to 2001 and NUTS3 data for 1993 to 1998 only.

In the review NUTS2 headline GVA data on a sub-regional basis was reconfigured to reflect the corresponding GVA per DNO service area. For example the NEDL area GVA was derived as comprising the North East Region and North Yorkshire (part of the Yorkshire and the Humber Region). In other instances where a more detailed disaggregation was required, NUTS3 data was used to indicate the proportioning of GVA by district (for example the disaggregation of Welsh GVA into SP Manweb and WPD South Wales distribution service areas).

As GVAs are published at current basic prices, the GVAs were brought onto a common 2002/03 price basis using the indices in the RP02 "All Items" index.

The trend of energy distributed against time is presented in the chart below

Trend of energy distributed against time



The total regulated units are HV and LV units and the total regulated units include EHV units. Up to and including 2003/03, the units distributed are actual units whereas from 2003/04 onwards these are forecast.

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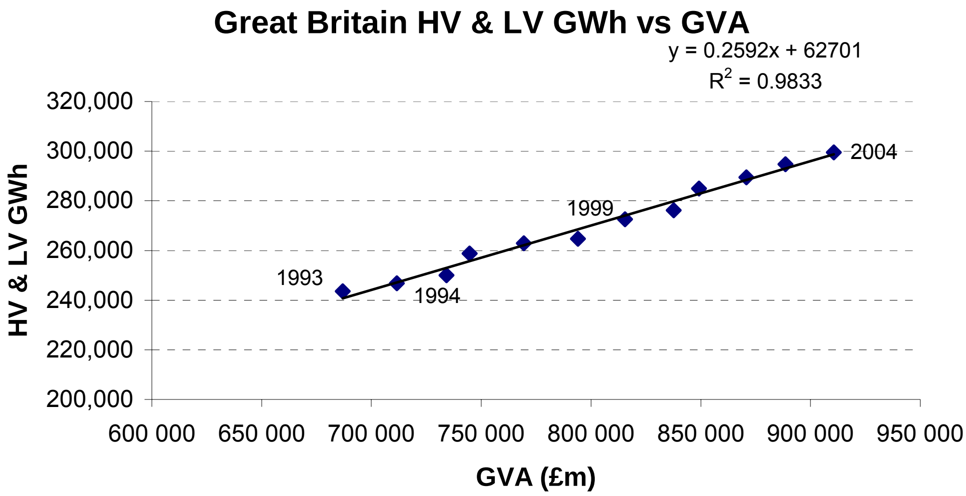
[1] Office of National Statistics: Local area and sub-regional gross domestic product, 26 April 2001, www.statistics.gov.uk

The average annual load growth of both total and combined HV and LV units from 2004/5 to 2009/10 is about 1.2 per cent nationally.

E.1.3 Historic trend of units distributed against GVA

The trend of HV and LV units distributed against GVA in Great Britain is presented in the chart below and shows a good correlation[2].



A comparison was also made between the percentage increases in units distributed (%ΔGWh) and (%ΔGVA). The national (Great Britain) average of %ΔGWh/%ΔGVA covering the years 1995/96 to 2001/02 (years of NUTS2 data availability) is about 0.7. Typical corresponding values for DNOs were calculated to be in the range of about 0.5 to 0.9.

E.1.4 GVA growth rates

Growth rates for GVA nationally for the years 2002/03 to and 2003/04 were obtained from ONS GDP statistics. By region a variety of published sources was used, including regional assemblies, regional development agencies and prominent econometric consultants.

For the years 2004/05 onwards, the HM Treasury "Forecasts for the UK Economy" dated February 20043 was used as the forecast for national growth. In a number of cases and, depending on the availability of published data, regional growth trends were estimated from the national trend but with a difference applied depending on the relative positions in 2003/2004.

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[2] To align GVA and GWh data, ONS data for 2001 was treated as corresponding to the review year 2001/02 and so on.

[3] www.hm-treasury.gov.uk/media//E7910/ACF11CB.pdf, "Forecasts for the UK Economy", February 2004.

FORECAST UK ANNUAL CHANGE IN GDP (GVA)
(%)

2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
1.7	2.1	2.8	2.6	2.5	2.5	2.3	2.3

As might be expected the highest forecast growth rates are in London and the South East. The lowest are in the North East of England and in Scotland. The underlying driver in the forecast growth is the service industry.

E.1.5 Derivation of GVA-based load forecasts

Forecasts of GVAs up to 2009/10 for each DNO service area were obtained by applying the forecast growth rates to the 2001/02 GVA data derived from the NUTS2 sub-regional GVA data referred to earlier.

For each of the years 1995 to 2001 and for each DNO, a plot was made of HV and LV units distributed against corresponding GVA and a linear “least squares fit” regression line applied. For 12 of the DNOs a good correlation (R-squared value > 0.8) was obtained. The remaining two DNOs showed R-squared values of about 0.6 and 0.7 respectively, reflecting year-on-year variations in units distributed.

The regression formulae for GWh versus GVA were applied to the forecast GVAs in order to obtain GVA-based forecasts of units distributed for each DNO. The individual forecasts for DPCR4 were adjusted pro rata so that the overall increase nationally was equal to that forecast by the DNOs.

APPENDIX F

NON-LOAD RELATED CAPEX MODELLING

APPENDIX F – NON-LOAD RELATED CAPEX MODELLING

F.1.1 NLRE asset replacement modelling for DPCR4

The NLRE that is modelled is that concerned with asset replacement and refurbishment, as charged against capital expenditure. The asset replacement modelling procedure and associated assumptions adopted for DPCR4 are described in this Appendix and are consistent with those discussed with DNOs during the course of the review. The input data used is, in the main, based on that provided by DNOs as part of the DPCR4 FBPQ process. Where PB Power has had need to supplement the DNO input data, such as the process of deriving a industry weighted average replacement profiles or use of PB Power's own replacement unit costs, then such actions have been highlighted.

F.1.1.1 Age-based replacement

A modelling technique has been employed for all switchgear, transformer, underground cable, submarine cable and overhead line asset types, with detailed variations as appropriate. This technique is equivalent to the "survivor" type analysis that formed the main input into DPCR3 non-load replacement modelling.

Fundamentally the model requires three input data items for each defined asset category, viz:

i. age profile
ii. retirement profile and
iii. unit cost.

The age profile defines the number of assets still in service and the current age of those assets.

The retirement profile represents the ages at which assets are retired from the system. These profiles are generally expressed as the fraction of assets that would be expected to be retired in each year over a given number of years of operation. For DPCR4 the retirement profiles have been based on Gaussian distributions defined according to the standard deviation and mean life of the asset types represented. As part of the modelling process we have derived industry weighted average replacement profiles for each asset type. These are normal distributions with mean asset lives obtained by weighting each DNO's expected useful life for the asset by the corresponding DNO asset population.

The unit costs are the replacement costs for items new plant and equipment on a per unit basis namely per transformer, per switchgear bay and per kilometre of underground cable. The schedule of PB Power's unit costs is presented in Appendix G.

The asset replacement calculation involves the cross-multiplication of the estimated original population of the assets of a given age with the assumed retirement fraction for assets of the same age. This process is carried out for assets of all ages such that the output of the model represents the total volume of assets to be replaced.

The asset volume is then multiplied by the appropriate unit replacement cost to give an estimate of the replacement expenditure for that asset type.

Our modelling of asset replacement and refurbishment concerns non-fault replacement and refurbishment; DNOs have been required to segregate fault and non-fault expenditure and the former may be considered as operating expenditure. Discussion with DNOs has been held on the issue of overlap between assets replaced due to fault and those replaced as a consequence of other asset management drivers. Given that these areas are modelled separately it is important that the risk of double-counting is reduced. In terms of transformer replacement it has been decided that, in general, replacement of pole-mounted transformers occur mainly as a result of a fault. Therefore, no pole-mounted transformers have been included in the modelled output of (non-fault) expenditure. The majority of cable replacement tends to be undertaken due to fault. Nevertheless DNOs have classified a certain volume of cable replacement as non-fault replacement . It is this non-fault replacement activity that is considered and hence included in the modelled output

F.1.1.2 Cyclic refurbishment / replacement

We investigated the direct modelling of refurbishment and replacement of overhead lines on a cyclic basis and found that it was not sufficiently robust in volumetric terms to reflect the refurbishment activity over a five-year period (DPCR4). Instead we found that replacement profile approach using an adjusted replacement profile provided an effective modelling approach, particularly in the case of HV and 33kV overhead line assets.

For these lines, in contrast to the single replacement unit cost required for the age-based replacement expenditure projection, the 'adjusted' refurbishment / replacement based model requires a blended unit cost based on an weighted average industry view taking account of the proportions of activity associated with refurbishment and replacement.

F.1.1.3 Assumptions

In order to complete our modelling of asset replacement we have found it necessary to make a number of assumptions. These are outlined below:

F.1.1.3.1 Overhead lines

a. **LV mains and services.** We compared the volumes forecast by the model for the five years of DPCR4 with those in the DNO submission and found that there was little difference between the two forecasts. Accordingly our modelling has used the industry weighted replacement profiles and our unit costs.

b. **HV and 33kV overhead lines.** The replacement/refurbishment of these lines has been modelled using 'adjusted' weighted industry average replacement profiles, obtained by "back-fitting" the replacement profile in order to match the volumes forecast by the model for the five years of DPCR4 with those in the DNO submission. The back-fitting resulted in adjustments to the mean asset lives, some increasing and others decreasing. The volumes derived from these profiles have been applied to a blended unit cost based on industry refurbishment and replacement activity.

c. For all assets with a rated voltage of 66 kV and greater (i.e. age-based asset replacement expenditure calculation) the mean life has been assumed to be 70 years. In PB Power's view the industry weighted average calculated for these asset types was considered too low.

d. The 12-year mean expected asset life declared in the FBPQ submission of one DNO for a number of asset types was considered to be a misinterpretation of the FPBQ as the 12 year life reflects the cyclic refurbishment period and not the mean asset life. That particular DNO's data has therefore been excluded from the industry weighted average replacement profile calculation. The asset types affected include LV mains and services, 6.6 & 11 kV bare and covered conductor, and 33 kV single and double circuit conductor overhead lines.

F.1.1.3.2 Underground cables

In general, the approach taken by the industry with regard to cable replacement is based largely on a reactive policy of undertaking fault repairs and of replacing lengths of cable only when such cable exhibits poor condition. In order to avoid possible over-forecasting of cable replacement volumes and to reflect the non-fault replacement volumes forecast by the DNOs, we have therefore adjusted the industry weighted average replacement profile of each main cable type before proceeding with age-based modelling. In general the resulting average asset lives have been increased. At LV, Consac cable has been modelled separately from the other LV cable types (PILC and Waveform have been combined) with the Consac replacement profile based on a much shorter average asset life than other types. One particular DNO's data on expected useful asset lives of LV, HV and 33kV cables was found to be inconsistent with that of other DNOs and has been excluded from the calculation of the industry average weighted replacement profiles.

F.1.1.3.3 Submarine cable

A 50-year mean life has been assumed for all asset types. One DNO has declared a 15 year mean life. As the DNO concerned has a relatively high forecast of submarine cable replacement its data would have had a significant impact on the industry weighted average asset life. Furthermore, 15 years is not in PB Power's view considered representative of the mean expected life of this asset type.

F.1.1.3.4 Benchmarking of DNO forecasts

Benchmarking of individual DNO submissions against corresponding outputs of the asset replacement model has been undertaken. This process has enabled the forecasts of individual companies to be compared thereby providing greater transparency with regard to asset class activity and highlighting any activity that may be atypical compared with industry norm performance levels. In the benchmarking process assets have been grouped under overhead lines and services, underground cables and services and substations (transformers, switchgear and substation other) enabling the forecast expenditure for each group to be benchmarked against corresponding model output. The output for each DNO by the asset classes of lines and services, cables and services and substations has been benchmarked against a median industry performer.

The approach to benchmarking has considered the DNO submission for asset replacement to include all asset replacement irrespective of the primary classification of causation such as: health and safety, environment or non-fault replacement. Expenditure associated with ESQCR has not been considered in this assessment and instead is expected to be the subject of a separate consideration by Ofgem. Combining the various asset replacement drivers into a single element overcomes differences in allocations between individual DNOs and hence avoids unduly penalising a particular company for internal allocation issues.

Certain asset classes have been combined for each DNO prior to any benchmarking assessment. This has been undertaken where the opportunity for imprecise asset replacement definition, common elements within unit cost and or related work may exist. For instance, certain expenditure items submitted as part of the DNO submission are referenced to substations with no clear attribution to either switchgear or transformer replacement. In order to avoid the risk of unjustified scaling back of companies through lack of a clear definition a generic class of substations has been created. This particular example is defined as all expenditure allocated to switchgear, transformer and other, including protection and civil works. Similarly, overhead line replacement has been combined with overhead service replacement given the likelihood that both activities will be undertaken within the same programme of work.

Certain adjustments to individual DNO submissions to compensate for pension deficit funding, lane rentals, inter-company margin and capitalised overheads have been made by Ofgem and these adjustments are taken into account. In order to determine a disaggregated forecast of capital expenditure that reconciles back to an Ofgem ‘adjusted’ submission it has been necessary to calculate a ratio between the company’s initial submission and the ‘adjusted’ submission. That ratio has been applied equally to each main asset class. These adjusted and combined generic-asset-classes form the basis from which a comparison to an equivalent asset replacement model output is drawn.

The model output is based on DNO data with regard to asset age profiles and replacement profiles from which industry average weighted replacement profiles have been derived. In that regard, the output from the model is industry-driven in terms of its input parameters. The only information that has been derived directly by PB Power has been asset replacement unit costs. A comparison of MEAVs for all 14 DNOs calculated using (new build) DNO unit costs and PB Power unit costs showed that these MEAVs were within 2 per cent of each other. A disaggregation of corresponding MEAVs by DNO in percentage terms by main asset groups and voltage levels is presented in Appendix G.

In the benchmarking process a comparison is made between the adjusted DNO submission and the corresponding model output for each of the three main asset groups:

- Lines and services
- Cables and services and
- Substations

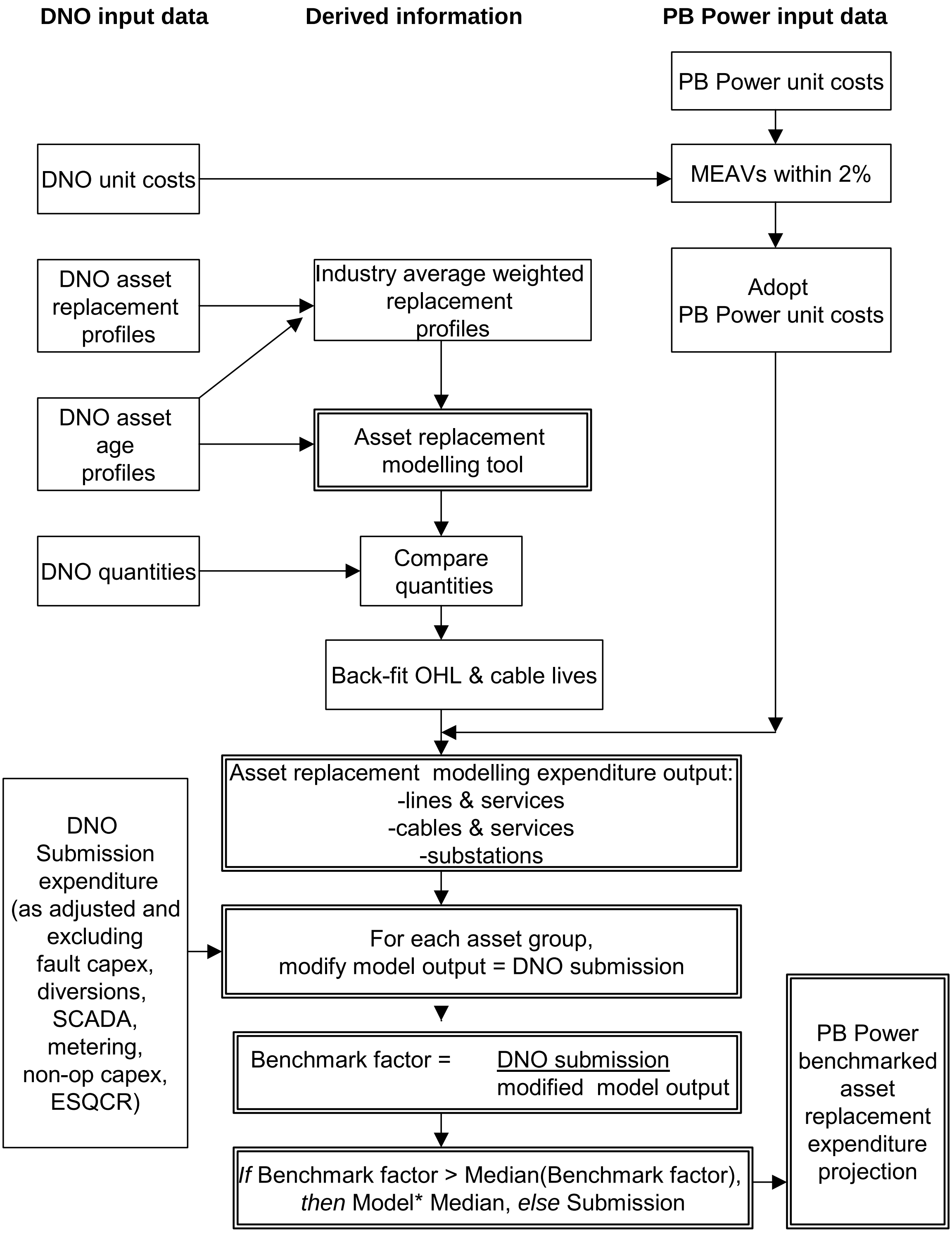
The model output is initially modified so that for each of the asset groups the overall industry (14 DNOs') expenditure predicted by the model is the same as that forecast by the DNOs. (The differences had in any case been small.) For each asset group, benchmark factors of DNO submission/model output are calculated and medians (about unity) obtained. Where the benchmark factor exceeds the median (submission exceeds model output), the resulting benchmarked output is the model output multiplied by the median. Otherwise the benchmarked output is the submission itself. Minor miscellaneous amounts not specifically included within asset groups in the FBPQ submission have been treated as pass-through with minor adjustments.

PB POWER INDUSTRY AVERAGE WEIGHTED REPLACEMENT PROFILES	MEAN LIFE (years)	STANDARD DEVIATION (years)
Overhead lines		
LV lines		
- LV mains Bare conductor	52	13
- LV mains Covered conductor	55	11
- LV services Bare conductor	51	12
- LV services Covered conductor	51	8
HV lines		
- 6.6 & 11 kV Bare conductor	45	11
- 6.6 & 11 kV Covered conductor	33	11
- 20kV Single circuit	51	11
EHV Lines		
- 33kV Single Circuit length	46	11
- 33kV Double Circuit length	69	8
- 66kV Single Circuit length - Towers	46	8
- 66kV Single Circuit length - Poles	55	8
- 66kV Double Circuit length	13	8
132kV		
- 132kV Single Circuit length	66	9
- 132kV Double Circuit length	67	12
Underground cables		
LV cables		
- LV mains (Consac)	54	14
- LV mains (PILC)	103	13
- LV mains (Plastic Waveform)	103	13
- LV services (PILC)	100	10
- LV services (Plastic Concentric)	100	10
HV cables		
- 6.6 & 11kV	85	12
- 20kV	103	16
EHV cables		
- 33kV	76	10
- 66kV	77	11
- 132kV	61	9

PB POWER INDUSTRY AVERAGE WEIGHTED REPLACEMENT PROFILES	MEAN LIFE (years)	STANDARD DEVIATION (years)
Submarine cables		
HV cables		
- 6.6 & 11kV	50	5
EHV cables		
- 33kV	50	5
- 132kV	50	6
Switchgear		
LV network		
- LV pillar	56	11
- LV Link box	90	12
HV network		
- 6.6 & 11kV switches (excluding RMU & CB)	47	8
- 6.6 & 11kV RMU	46	8
- 6.6 & 11kV CB	52	7
- 6.6 & 11kV A/RC & Sect, urban automation	42	8
EHV network		
- 33kV CB (I/D)	53	7
- 33kV CB (O/D)	52	10
- 33kV Isol (I/D)	59	8
- 33kV Isol (O/D)	53	10
- 66kV CB (GIS) (I/D)	53	10
- 66kV CB (GIS) (O/D)	50	6
- 66kV CB - other (I/D)	52	9
- 66kV CB - other (O/D)	49	7
- 66kV Isol (I/D)	55	12
- 66kV Isol (O/D)	58	10
- 132kV CB (GIS) (I/D)	56	6
- 132kV CB (GIS) (O/D)	50	8
- 132kV CB - other (I/D)	48	9
- 132kV CB - other (O/D)	49	10
- 132kV Isol (I/D)	50	7
- 132kV Isol (O/D)	48	9

PB POWER INDUSTRY AVERAGE WEIGHTED REPLACEMENT PROFILES	MEAN LIFE (years)	STANDARD DEVIATION (years)
Transformers		
HV network		
- 6.6kV PMT	55	15
- 6.6kV GMT	54	14
- 11kV PMT	56	10
- 11kV GMT	58	11
- 20kV PMT	60	9
- 20kV GMT	50	10
EHV network		
- 33kV PMT	55	12
- 33kV GMT	60	10
- 66kV	53	9
- 132kV	55	11

ASSET REPLACEMENT BENCHMARKING FLOWCHART



APPENDIX G

UNIT COSTS AND MODERN EQUIVALENT ASSET VALUE

APPENDIX G - UNIT COSTS AND MODERN EQUIVALENT ASSET VALUE

PB POWER – SCHEDULE OF UNIT COSTS

PB POWER – SCHEDULE OF UNIT COSTS		LRE	NLRE
NB. Unit costs of OHL circuit lengths include costs of supports (poles/towers), except for 66kV and 132kV replacement/refurbishment costs which exclude supports.	Unit	(new build)	(replacement/ refurbishment)
(2002/03 price levels)		(£ 000s)	(£ 000s)
Overhead lines			
LV lines			
- LV mains Bare conductor	km	25.5	25.5
- LV mains Covered conductor	km	27.5	27.5
- LV services Bare conductor	km	20.7	20.7
- LV services Covered conductor	km	23.6	23.6
HV lines			
- 6.6 & 11 kV Bare conductor	km	33.1	20.0
- 6.6 & 11 kV Covered conductor	km	43.2	26.0
- 20kV Single circuit	km	34.9	34.9
EHV Lines			
- 33kV Single Circuit length	km	38.2	38.2
- 33kV Double Circuit length	route km	60.0	60.0
- 66kV Single Circuit length - Towers	km	130.4	71.7
- 66kV Single Circuit length - Poles	km	85.1	46.8
- 66kV Double Circuit length	km	204.9	112.7
132kV			
- 132kV Single Circuit length	route km	168.4	92.6
- 132kV Double Circuit length	route km	332.8	183.1
Underground cables			
LV cables			
- LV mains (Consac)	km	58.8	58.8
- LV mains (PILC)	km	58.8	58.8
- LV mains (Plastic Waveform)	km	58.8	58.8
- LV services (PILC)	km	35.6	35.6
- LV services (Plastic Concentric)	km	35.6	35.6
HV cables			
- 6.6 & 11kV	km	88.7	88.7
- 20kV	km	127.6	127.6
EHV cables			
- 33kV	km	195.8	195.8
- 66kV	km	826.9	826.9
- 132kV	km	1,012.5	1012.5

PB POWER - DATABASE OF UNIT COSTS (continued)		LRE	NLRE
(2002/03 price levels)	**Unit**	(new build) (£ 000s)	(replacement/ refurbishment) (£ 000s)
Submarine cables (km)			
HV cables			
- 6.6 & 11kV	km	105.8	105.8
EHV cables			
- 33kV	km	496.1	496.1
- 132kV	km	1,277.6	1277.6
Switchgear (units)			
LV network			
- LV pillar	each	4.3	4.3
- LV Link box	each	1.1	1.1
HV network			
- 6.6 & 11kV switches (excluding RMU & CB)	each	7.3	7.3
- 6.6 & 11kV RMU	each	11.3	11.3
- 6.6 & 11kV CB	each	27.8	27.8
- 6.6 & 11kV A/RC & Sect, urban automation	each	11.0	11.0
EHV network			
- 33kV CB (I/D)	each	76.8	76.8
- 33kV CB (O/D)	each	54.0	54.0
- 33kV Isol (I/D)	each	7.6	7.6
- 33kV Isol (O/D)	each	7.6	7.6
- 66kV CB (GIS) (I/D)	each	311.7	311.7
- 66kV CB (GIS) (O/D)	each	311.7	311.7
- 66kV CB - other (I/D)	each	311.7	311.7
- 66kV CB - other (O/D)	each	311.7	311.7
- 66kV Isol (I/D)	each	8.0	8.0
- 66kV Isol (O/D)	each	8.0	8.0
- 132kV CB (GIS) (I/D)	each	1,012.5	1012.5
- 132kV CB (GIS) (O/D)	each	519.6	519.6
- 132kV CB - other (I/D)	each	519.6	519.6
- 132kV CB - other (O/D)	each	519.6	519.6
- 132kV Isol (I/D)	each	13.5	13.5
- 132kV Isol (O/D)	each	13.5	13.5

PB POWER - DATABASE OF UNIT COSTS (continued)		LRE	NLRE
(2002/03 price levels)	Unit	(new build) (£ 000s)	(replacement/ refurbishment) (£ 000s)
Transformers (units) - including tap changes and reactors			
HV network			
- 6.6kV PMT	each	3.0	3.0
- 6.6kV GMT	each	10.5	10.5
- 11kV PMT	each	3.0	3.0
- 11kV GMT	each	10.5	10.5
- 20kV PMT	each	3.7	3.7
- 20kV GMT	each	15.7	15.7
EHV network			
- 33kV PMT	each	4.3	4.3
- 33kV GMT	each	317.5	317.5
- 66kV	each	337.8	337.8
- 132kV	each	929.8	929.8

MODERN EQUIVALENT ASSET VALUE (MEAV)

On the following page a disaggregation of the MEAVs of the DNOs is presented, from asset quantities declared by the DNOs and from PB Power's unit costs. The total MEAV of all the 14 DNOs is calculated at some £86.6 billion.

MEA SUMMARY		Calculated using PB Power's Unit Costs					
		Trans-formers	**Switchgear**	**Overhead Line**	**Under-ground Cable**	**Services**	**Total**
1	**EHV**	52%	34%	32%	17%	0%	23%
	HV	48%	52%	53%	36%	0%	35%
	LV	0%	14%	14%	47%	100%	42%
	Total	11%	10%	23%	34%	22%	100%
2	**EHV**	63%	51%	39%	28%	0%	34%
	HV	37%	45%	45%	26%	0%	31%
	LV	0%	4%	16%	46%	100%	34%
	Total	11%	14%	19%	45%	10%	100%
3	**EHV**	60%	26%	53%	14%	0%	22%
	HV	40%	60%	36%	32%	0%	29%
	LV	0%	15%	11%	54%	100%	49%
	Total	8%	10%	15%	44%	22%	100%
4	**EHV**	54%	25%	60%	20%	0%	23%
	HV	46%	57%	25%	33%	0%	28%
	LV	0%	18%	15%	47%	100%	49%
	Total	8%	10%	12%	46%	23%	100%
5	**EHV**	54%	23%	51%	17%	0%	26%
	HV	46%	64%	35%	35%	0%	34%
	LV	0%	13%	13%	48%	100%	40%
	Total	10%	9%	20%	49%	12%	100%
6	**EHV**	56%	28%	47%	14%	0%	22%
	HV	44%	62%	40%	36%	0%	33%
	LV	0%	10%	13%	50%	100%	45%
	Total	8%	13%	18%	39%	22%	100%
7	**EHV**	51%	30%	100%	29%	0%	26%
	HV	49%	51%	0%	26%	0%	26%
	LV	0%	19%	0%	44%	100%	48%
	Total	6%	9%	0%	71%	15%	100%
8	**EHV**	55%	31%	50%	24%	0%	28%
	HV	45%	66%	41%	33%	0%	33%
	LV	0%	3%	9%	44%	100%	39%
	Total	7%	12%	18%	47%	17%	100%
9	**EHV**	62%	28%	58%	17%	0%	26%
	HV	38%	68%	33%	30%	0%	32%
	LV	0%	4%	10%	53%	100%	42%
	Total	9%	13%	13%	54%	11%	100%
10	**EHV**	62%	28%	63%	27%	0%	31%
	HV	38%	70%	32%	27%	0%	31%
	LV	0%	3%	5%	46%	100%	38%
	Total	8%	14%	14%	49%	14%	100%
11	**EHV**	54%	45%	36%	14%	0%	24%
	HV	46%	43%	55%	38%	0%	35%
	LV	0%	12%	8%	49%	100%	41%
	Total	11%	12%	21%	34%	21%	100%
12	**EHV**	51%	12%	15%	16%	0%	16%
	HV	49%	73%	68%	35%	0%	40%
	LV	0%	15%	17%	50%	100%	45%
	Total	9%	13%	12%	51%	15%	100%
13	**EHV**	47%	16%	25%	22%	0%	23%
	HV	53%	68%	65%	39%	0%	48%
	LV	0%	16%	10%	39%	100%	29%
	Total	11%	10%	33%	35%	11%	100%
14	**EHV**	56%	23%	57%	25%	0%	31%
	HV	44%	64%	29%	32%	0%	33%
	LV	0%	13%	14%	43%	100%	36%
	Total	10%	14%	19%	46%	11%	100%
All 14 DNOs	**EHV**	56%	28%	46%	21%	0%	26%
	HV	44%	61%	41%	32%	0%	33%
	LV	0%	11%	12%	47%	100%	58%
	Total	9%	12%	16%	48%	16%	100%